

Client **Moldova Energy Project Implementation Unit**
Termoelectrica S.A.

Project **Second District Heating Efficiency Improvement Project (DHEIP2)**

Assignment
Consultancy services for Feasibility Study for new high-efficiency heat and power generation facilities for Termoelectrica S.A.

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ДРУШТВО ЗА ИНЖЕНЕРИНГ И КОНСАЛТИНГ КОЛЕНКО ДООЕЛ СКОПЈЕ

Nikola Bitrak
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ABBREVIATIONS

ABBREVIATION	MEANING
ACSR	Aluminium Conductor Steel Reinforced
AFBC	Atmospheric Fluidised Bed Combustion
AISI	American Iron and Steel Institute
ANRE	National Energy Regulatory Agency
BAU	Business as Usual
BFB	Bubbling Fluidised Bed
BTI	Bureau of Technical Inventory
CAPEX	Capital Expenditure
CCPP	Combined Cycle Power Plant
CET	Combined Heat and Power Plant (CHP)
CF	Complementary Facilities
CFBC	Circulating Fluidised Bed Combustion
CHP	Combined Heat and Power
CHPP	Combined Heat and Power Plant
COP	Coefficient of Performance
CT	Hot Water Boiler (HOB)
CTS	Centralised Thermal System
DH	District Heating
DHEIP	District Heating Efficiency Improvement Project
DHEIP2	Second District Heating Efficiency Improvement Project
DHS	District Heating System
DHW	Domestic Hot Water
DKVR	Type of Boiler (Steam Boiler Model)
DLE	Dry Low Emissions
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest, Taxes, Depreciation, and Amortisation
EBRD	European Bank for Reconstruction and Development
EBT	Earnings Before Taxes
EC	European Commission
ECU	Engine Control Unit
EE	Electrical Energy
EHWB	Electric Hot Water Boiler
EIA	Environmental Impact Assessment
EIB	European Investment Bank
EN	European Norms
ENTSOE	European Network of Transmission System Operators for Electricity
EP	Energy Performance
EPBD	Energy Performance of Buildings Directive
EPC	Engineering, Procurement, and Construction
EPP	Electrical power potential
ESA	Environmental and Social Assessment
ESCO	Energy Service Company
ESIA	Environmental and Social Impact Assessment
ESMS	Environmental and Social Management System

ESS	Environmental and Social Standards
ETC	Evacuated Tube Collector
ETS	Emissions Trading System
EU	European Union
EUR	Euro
FPAKM	Fossil Primary Aggregate Key Metric
FPC	Flat Plate Collector
FS	Feasibility Study
GE	Gas Engine
GHG	Greenhouse Gas
GM	General Motors
GRES	State Regional Electric Station
GT	Gas Turbine
GWP	Global Warming Potential
HDD	Heating Degree Days
HFO	Heavy Fuel Oil
HOB	Heat Only Boiler
HP	Heat Pump
HPC	high-Pressure Compressor
HPP	Hydroelectric Power Plant
HPT	High Pressure Turbine
HRB	Heat Recovery Boiler
HRGS	Heat Recovery Generation System
HRHB	Heat Recovery Hot Water Boiler
HRHG	Heat Recovery High-Grade Boiler
HRSB	Heat Recovery Steam Boiler
HUPX	Hungarian Power Exchange
HVFPC	High-Vacuum Flat Plate Collector
ICE	Internal Combustion Engine
IFI	International Financial Institution
IFRS	International Financial Reporting Standards
IHS	Individual Heat Substation
IPPU	Industrial Processes and Product Use
IPS	Integrated Power System
IR	Infrared Radiation
IRR	Internal Rate of Return
ISO	International Organisation for Standardisation
JCM	Joint Crediting Mechanism
JSC	Joint Stock Company
JV	Joint Venture
KW	Kilowatt
LCOH	Levelised Cost of Heat
LHV	Lower Heating Value
LP	Low Pressure
LPC	Low Pressure Compressor
LPG	Liquefied Petroleum Gas

LPT	Low Pressure Turbine
LULUCF	Land Use, Land-Use Change and Forestry
MDL	Moldovan Leu
ME	Ministry of Energy
MECL	Minimum Allowable Generation Capacity
MEPIU	Moldova Energy Projects Implementation Unit
MFB	Multi-Family Building
MGRES	Moldovan State Regional Electric Station
MHPS	Mitsubishi Hitachi Power Systems
MIDR	Ministry of Infrastructure and Regional Development
MJ	Megajoule
MNQC	Multi-Nozzle Quiet Combustor
MRV	Monitoring, Reporting, and Verification
MSW	Municipal Solid Waste
MT	Medium Temperature
MVA	Megavolt Ampere
MW	Megawatt
NBS	National Bureau of Statistics
NCM	National Climate Mitigation
NDC	Nationally Determined Contribution
NECP	National Energy and Climate Plan
NEK	National Energy Corporation
NPV	Net Present Value
NVC	Net Value Cost
OHS	Occupational Health and Safety
OLTC	On-Load Tap Changer
OPCOM	Romanian Electricity Market Operator
OPEX	Operational Expenditure
PAH	Polycyclic Aromatic Hydrocarbons
PFBC	Pressurised Fluidised Bed Combustion
PJSC	Public Joint Stock Company
PLC	Programmable Logic Controller
PPP	Public-Private Partnership
PTVM	Hot Water Boiler Model
PU	Polyurethane
PV	Photovoltaic
RDF	Refuse-Derived Fuel
RES	Renewable Energy Sources
RFP	Request for Proposal
ROA	Return on Assets
ROE	Return on Equity
SAC	Strong Acid Cation
SAIDI	System Average Interruption Duration Index
SBA	Strong Base Anion
SEP	Stakeholder Engagement Plan
SGT	Siemens Gas Turbine

SME	Small and Medium-sized Enterprises
SRF	Solid Recovered Fuel
SRL	Limited Liability Company
SSP	Shared Socioeconomic Pathways
ST	Steam Turbine
TDS	Total Dissolved Solids
TJ	Terajoule
TOC	Total Organic Carbon
TRDN	Transmission and Distribution Network
TWG	Technical Working Group
UNDP	United Nations Development Programme
UPS	Uninterruptible Power Supply
VAT	Value Added Tax
VFPC	Vacuum Flat Plate Collector
VPFC	Variable Profile Flat Collector
WACC	Weighted Average Cost of Capital
WAM	With Additional Measures
WB	World Bank
WBG	World Bank Group
WEM	With Existing Measures
WGI	Waste Generation Indices
WTE	Waste-to-Energy
XLPE	Cross-Linked Polyethylene

1. Executive Summary

1.1 Key objectives of the feasibility study

The feasibility study aims to evaluate and recommend the most suitable solution for developing a new high-efficiency Combined Heat and Power (CHP) plant in Chisinau. This facility is intended to replace the existing units at CHP Source-1, which have reached or are nearing the end of their permitted operational lifetime. The project is crucial for ensuring the continued reliability and efficiency of the district heating and power generation systems, addressing both current and future energy demands in Chisinau and Moldova as a whole.

Through a detailed analysis of technical, economic, financial, and environmental factors, the study provides actionable insights into the design, capacity, and technologies needed for the new CHP plant. It ensures compliance with international best practices, local energy regulations, and sustainability principles, while also considering the integration of innovative solutions such as renewable energy and waste-to-energy options.

Key goals:

- ✔ Assess multiple alternatives for the development of the new CHP plant
- ✔ Optimise design and capacity to address Chisinau's heating needs and electricity production needs efficiently
- ✔ Evaluate the financial and economic viability of proposed solutions
- ✔ Analyse environmental and social impacts in compliance with relevant standards
- ✔ Deliver a clear recommendation for the most feasible alternative, supported by robust data and models

1.2 Scope of the feasibility study

The feasibility study involved a comprehensive evaluation of technical, economic, and environmental aspects to support the planning and implementation of the new CHP plant. It assessed the current state of energy demand, incorporated future projections, and proposed sustainable solutions to ensure the long-term efficiency and reliability of the district heating and power systems.

Key deliverables include:

Inception Report

A detailed methodology and timeline for the study.

Financial Analysis Report

An assessment of Termoelectrica S.A.'s financial capacity, historical performance, and ability to support the project, including key financial indicators and projections.

Energy Model

Comprehensive energy balance calculations, heat and electricity demand assessments, and cost estimations for proposed alternatives.



Economic and Technical Model

A comparative analysis of five technical alternatives, including capacity, technology, and cost estimates.



Financial Model

A detailed financial model to assess project costs, revenues, and key financial indicators such as IRR, NPV, and payback periods, along with sensitivity analyses.



Environmental and Social Assessment Report

An evaluation of environmental impacts, compliance requirements, and social considerations.



Draft Final Report

An integrated document summarising all findings, analyses, and recommendations.



Final Comprehensive Report

A refined version of the Draft Final Report, incorporating feedback from stakeholders, along with all deliverables in editable formats and a PowerPoint presentation.

All reports were prepared in accordance with the World Bank's and Moldova's requirements, ensuring clarity, accessibility, and alignment with the project's objectives.

1.3 Key findings

1.3.1 Legislation framework

Moldova's energy sector operates within a comprehensive legislative framework designed to secure energy independence, promote sustainable practices, and align the nation's energy policies with European Union standards. Over the last decade, the government has introduced key laws and regulations aimed at fostering energy efficiency, integrating renewable energy sources, and modernising critical infrastructure. These legal instruments provide a solid foundation for ongoing developments, including advancements in cogeneration and the adoption of innovative technologies.

A pivotal element of this framework is the focus on long-term planning and alignment with international commitments. The National Energy and Climate Plan (NECP) serves as a roadmap for achieving Moldova's energy and environmental goals by 2030. This plan outlines specific measures to improve energy efficiency, expand renewable energy integration, and reduce greenhouse gas emissions, reinforcing the critical role of legislation in shaping the country's energy future.

Key Legislative Frameworks

Moldova's energy sector is governed by several essential laws and policies that underpin its operational and strategic priorities:

ENERGY LAW NO. 174/2017	• Establishes the overarching principles for energy production, distribution, and supply. • Encourages the liberalisation of the energy market while ensuring consumer rights and affordability. • Promotes investments in cleaner, more efficient energy technologies.
LAW ON THERMAL ENERGY AND THE PROMOTION OF COGENERATION NO. 92/2014	• Provides a legal basis for the operation and development of CHP plants. • Incentivises high-efficiency cogeneration through subsidies, tax benefits, and priority grid access. • Aligns with EU directives on energy efficiency and emissions reduction.
RENEWABLE ENERGY LAW NO. 10/2016	• Creates a framework for the development and integration of renewable energy sources (RES). • Supports the use of biomass, biogas, and RDF in cogeneration systems. • Introduces green certificates and feed-in tariffs to attract investments in RES projects.
ENERGY EFFICIENCY LAW NO. 139/2018	• Defines national targets for reducing energy consumption across sectors. • Establishes mechanisms to finance modernisation projects, including DH systems. • Mandates the implementation of efficiency measures in public and private infrastructure.

The National Energy and Climate Plan (NECP)

The NECP represents Moldova's strategic commitment to sustainable energy and climate objectives, aligning with EU policies and the Paris Agreement. It identifies specific targets and measures to transform the energy sector, with an emphasis on energy security, decarbonisation, and economic competitiveness. Key components include:

DECARBONIZATION	ENERGY EFFICIENCY
▪ **GHG emissions and removals:** – Carbon emissions reduction; – Fulfilling obligations of the Paris Agreement and of the Energy Community; – Contributing to the EnC – 60.9% GHG emissions reduction target with national emissions reduction in 2030; – Attaining the national GHG emissions reduction target for the Right bank of the Dniester River by 68.6% in 2030 compared to the 1990 level. ▪ **Renewable energy:** – Attaining the national target for Renewable Energy share in final energy consumption is of 27% in 2030	▪ Contribution to attaining the national target for energy consumption is of 2.80 Mtoe in the Final Energy Consumption in 2030. ▪ In terms of maximum Share of Primary Energy Consumption, the target is of 3.00 Mtoe in 2030. ▪ Implementation of the Directive (EU) 2012/27, as amended by Directive (EU) 2018/2002, Law on Energy Performance of Buildings. ▪ Assessment of the implementation of Law No. 139/2018 on Energy Efficiency. ▪ Implementation of the Law No. 139/2018 on Energy Efficiency, transposition and implementation of Directive (EU) 2012/27/EU as amended by Directive (EU) 2018/2002.
Ensuring the institutional framework for coordination in the area of monitoring, reporting and verification, as well as facilitating the integration of climate change aspects into national and sectoral programs and plans	
Specific objective 5: "Increasing the resilience of priority sectors by financing activities in the field of adaptation to climate change and reducing the risks and negative impacts of climate hazards";	

Priority action 5.2: "Increasing the energy efficiency and resilience of the energy sector infrastructure by adjusting to forecasted hydro-meteorological parameters"	▪ Reduce greenhouse gas emissions and enhance climate resilience in the buildings sector, increase share of RES in electricity, increase share of RES in heating and cooling. ▪ Consumer protection and improvement of competition, enable EE at the supply side (i.e. through the reduction of losses).
Reduction of Pollution and GHG emissions	
F-gases emissions reduction	
To manage usage, identify energy saving opportunities, conserve consumption and reduce carbon emissions	
Increase of carbon removals	

The NECP underscores the critical role of cogeneration and renewable energy projects in achieving these goals, highlighting the importance of legislative support and financial mechanisms.

Focus on Cogeneration

Cogeneration remains a cornerstone of Moldova's energy strategy, supported by favourable legislation and government incentives. This technology enables the simultaneous production of electricity and heat, maximising fuel utilisation and minimising waste. The legislative framework not only facilitates the development of large-scale CHP plants but also encourages decentralised mini-CHP systems to address regional energy needs.

Legislative support for cogeneration:

- Incentives for Efficiency: CHP operators may benefit from tax exemptions and subsidies for infrastructure upgrades.
- Streamlined Permitting: simplified approval processes encourage private sector investment in cogeneration facilities.
- Mandatory Efficiency Targets: legislation enforces strict efficiency benchmarks to ensure compliance with EU directives.

Challenges and Opportunities

While Moldova's legislative framework is comprehensive, implementation and enforcement present notable challenges. Addressing these gaps will unlock significant opportunities for sectoral growth and sustainability.

CHALLENGES	OPPORTUNITIES
● Limited financial resources for fully implementing legislative provisions.	● Expanding international cooperation for funding and expertise, particularly with EU institutions.
● Infrastructure constraints, particularly for large-scale RES integration alongside cogeneration systems.	● Enhancing public-private partnerships to drive investment in cogeneration and renewable energy projects.
● Regulatory gaps in monitoring and enforcement of efficiency and emissions standards.	● Modernising legislation to accommodate emerging technologies such as energy storage and hydrogen integration.

Moldova's legislative framework reflects a forward-looking approach that balances energy security, sustainability, and market liberalisation. The National Energy and Climate Plan and associated laws provide a solid foundation for modernising the energy sector, with cogeneration and renewable energy integration at the core. By addressing implementation challenges and fostering innovation, Moldova is well-positioned to achieve its energy and climate goals, ensuring a greener and more resilient future for its citizens.

1.3.2 Financial Analysis of Termoelectrica S.A.

Termoelectrica S.A. is the leading producer of electrical and thermal energy and supplier of district heating services in Chisinau and its surrounding suburbs, catering to over 500,000 consumers, including residential, educational, medical, administrative and commercial facilities. As Moldova's foremost producer of cogeneration electricity, the company supplies approximately 650 million kWh annually, covering circa 15% of the country's electricity consumption. Additionally, it distributes around 1.3 million Gcal of thermal energy each year through its urban and suburban networks.

Created in 2015 (as a result of the merger of Termocom S.A., CET-1 S.A. and CET-2 S.A.), Termoelectrica S.A. functions under licenses issued by the National Energy Regulatory Agency and employs over 1,700 skilled professionals. Its strategic focus lies in the centralised production and distribution of energy, supported by continuous investments in modernising its infrastructure to meet growing consumer demand efficiently.

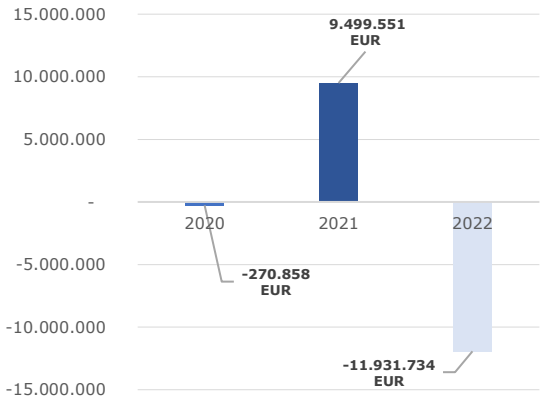
A thorough analysis of the company's financial performance over recent years provides insight into its operational strengths, challenges, and future prospects. Below are key findings from the financial review for 2020–2022.

Financial Performance Highlights (2020–2022)

The financial performance of Termoelectrica S.A. reflects a period of significant growth in revenue but also showcases challenges due to rising operational costs and market volatility. Understanding these trends is critical for assessing the company's current position and future resilience.

Revenue and profitability trends	Evolution of net profit (net loss) for the period 2020-2022 (EUR)

- **Revenue growth:** the company demonstrated significant growth in total revenue:
  - 2020: €119.2 million
  - 2021: €160.5 million (+40% YoY)
  - 2022: €252.6 million (+57% YoY)
- **Net profit/loss:**
  - 2020: Loss of €270,858
  - 2021: Profit of €9,499,551
  - 2022: Loss of €11,931,734



Key insights:

- Primary revenue (94.9% in 2022) stems from electricity and thermal energy sales.
- Other revenue sources include asset leases, exchange rate gains, and exceptional income.
- The 2022 loss was primarily driven by rising operational costs, particularly energy tariffs linked to global market volatility and energy crisis.

Capital, Liquidity, and Debt Structure

To maintain operational stability and finance ongoing projects, Termoelectrica S.A. has increasingly relied on external financing. While this strategy has supported short-term objectives, it has also led to higher financial risks that must be managed carefully.

Debt trends (2020-2022):

- **Debt-to-equity ratio:** increased from 1.73 (2020) to 3.38 (2022), reflecting higher reliance on external financing.
- **Equity ratio:** declined from 0.37 (2020) to 0.23 (2022), highlighting reduced self-financing capacity.
- **Long-term debt-to-equity:** grew from 1.64 (2020) to 2.38 (2022).

Liquidity indicators:

- **Immediate liquidity ratio:** 0.22 in 2022 (within the optimal range of 0.2–0.3).
- **Current liquidity ratio:** 1.57 in 2022 (below 2020 levels, indicating growing short-term obligations).

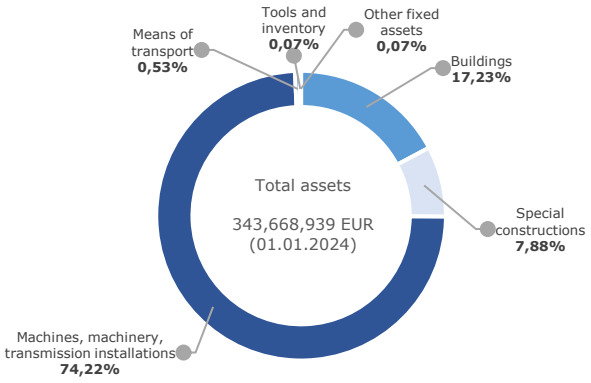
Recommendation: The company should focus on balancing debt levels with equity and maintaining robust liquidity to mitigate potential financial risks from market fluctuations.

Asset Structure and Investments

Termoelectrica S.A.'s asset portfolio reflects its commitment to maintaining high operational standards and investing in sustainable growth. Strategic investments in infrastructure and equipment have significantly enhanced its capacity to deliver reliable energy services.

The composition of total assets as of January 1, 2024 (%)

- **Key asset categories:**
  - Machinery, equipment, and transmission installations: 74.22%
  - Buildings: 17.23%
  - Special constructions: 7.88%
  - Other fixed assets: <1%
- **Total asset value:** €343.7 million



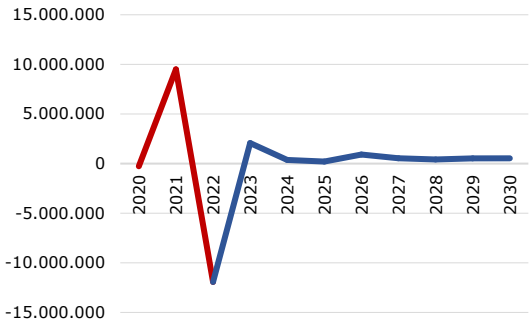
These investments have been directed toward modernising critical infrastructure, ensuring improved efficiency and reliability in energy delivery. Such initiatives underscore the company's strategic focus on long-term value creation and operational excellence.

Strategic Projections (2024–2030)

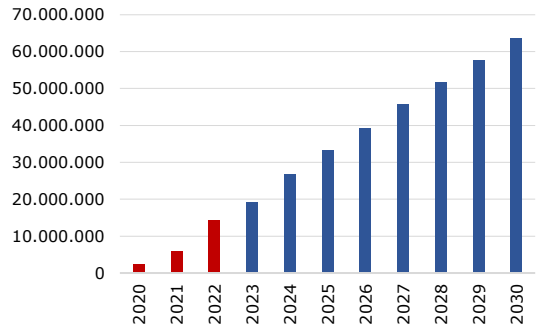
Future projections for Termoelectrica S.A. are built on key assumptions about energy pricing, production volumes, and tariff adjustments. The company anticipates steady growth supported by its strategic initiatives.

- **Revenue forecast:** €236.0 million in 2030.
- **Net cash flow from operations:** expected to reach €7.45 million in 2030.
- **Cash balance:** projected to grow from €57.6 million (start of 2030) to €63.5 million (end of 2030).

Profit and loss forecast, 2024-2030 (EUR)



Cash flow forecast, 2024-2030 (EUR)



While the projections are optimistic, the company must navigate challenges such as fluctuating natural gas prices and rising production costs. Effective cost management and strategic decision-making will be essential to achieving sustainable growth.

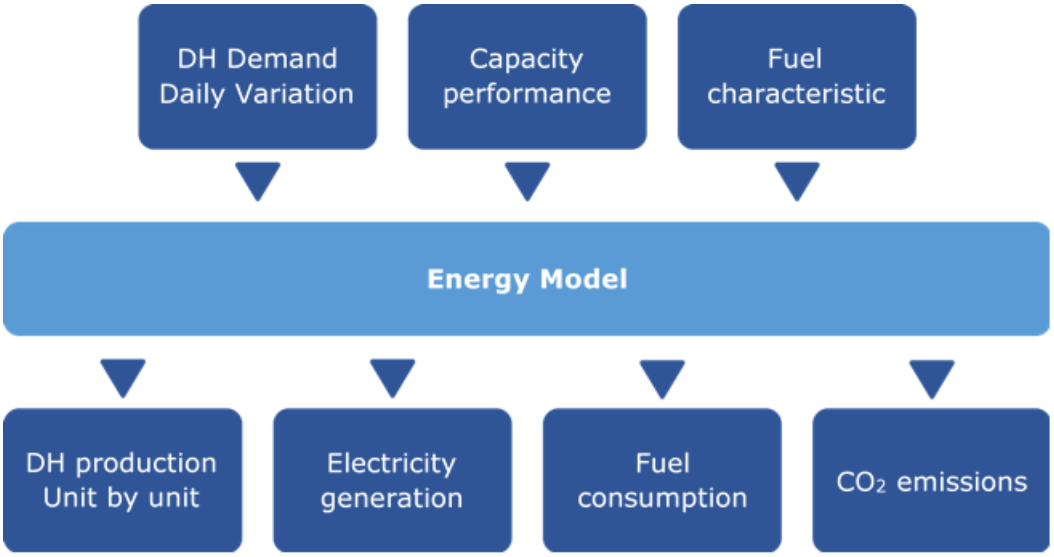
General Conclusions

Termoelectrica S.A. demonstrates resilience and adaptability amidst financial and operational challenges. Strategic investments in modernisation and infrastructure have bolstered the company's capacity to meet current and future energy demands. However, heightened debt reliance and increasing operational costs necessitate proactive financial and operational strategies. Continued focus on cost optimisation, debt management, and revenue diversification will be essential for long-term stability and growth.

1.3.3 Energy model

Structure of the Energy Model

A central component of the feasibility study for the new CHP plant in Chisinau (including complementary WtE and renewable energy facilities) is the Energy Model, which serves as the analytical framework for evaluating different configurations and operational scenarios. This model was designed to simulate the interaction between electricity and heat production, taking into account demand variations, plant efficiency, fuel consumption, and environmental impact.



The structure, as illustrated in figure above, combines critical input data and outputs to deliver actionable insights:

Inputs:

- District heating demand curves: incorporating current and projected heat consumption.
- Capacity metrics: performance benchmarks for existing and future production units.
- Fuel characteristics: properties of natural gas and RDF.

Outputs:

- Heat production forecasts (unit-by-unit).
- Electricity generation metrics.
- Detailed projections of CO2 emissions and fuel consumption.

The Energy Model integrates district heating demand projections, electricity market conditions, and fuel pricing scenarios, allowing for a comprehensive evaluation of system performance. It operates based on a time-step simulation, ensuring that seasonal variations in heat and power demand are accurately represented. The model includes functional modules for:

- **CHP unit operation**, simulating the performance of gas turbines, heat recovery steam boiler (HRSB), and steam turbines under different load conditions, as well as gas engines.
- **Electricity market participation**, assessing revenue potential under market-based pricing mechanisms.
- **Fuel consumption and emissions analysis**, estimating natural gas usage and CO_2 emissions under various efficiency scenarios.
- **Thermal Energy Storage (TES) integration**, modelling heat accumulation and discharge to optimize district heating supply.

Each unit within the model is defined by its technical specifications, including electrical efficiency, heat-to-power ratio, and load flexibility. The simulation is structured to evaluate two primary operational modes:

1. **Maximum electricity production mode**, where the plant prioritizes power generation to maximize revenues from electricity sales while ensuring sufficient heat production for district heating.

2. **Maximum efficiency mode**, where the plant optimizes its fuel utilization by maintaining the highest possible combined efficiency for heat and power generation.

This approach allows the Energy Model to identify the most cost-effective and reliable operational strategy for the new CHP plant while ensuring compliance with regulatory and environmental requirements.

Heat Energy Demand of Chisinau

Understanding the current and future heat energy demand of Chisinau is crucial for tailoring infrastructure to meet both immediate needs and long-term objectives. The analysis focuses on both heating and domestic hot water (DHW) demands, offering a detailed methodology, historical context, and forward-looking projections.

In Chisinau, consumers of centralised heat energy for heating are distributed across five districts. The majority are connected to CHP Source-1 and CHP Source-2, which supply heat to all five districts, while the heat-only boiler plants cater to individual districts/areas during the cold season: HOB-West serves the Buiucani district, and HOB-South provides heat to an area in the south-west part of Chisinau ("Telecentru" area). In 2021[1], the total number of consumers connected to the centralised heating system reached 9,302*.

Source	Ciocana	Centru	Riscani	Botanica	Buiucani	Total
CHP Source-1 / Source-2	1,571	1,667	2,344	1,490	263	**7,335**
HOB-West	-	-	-	-	1,335	**1,335**
HOB-South	-	632	-	-	-	**632**
Total	**1,571**	**2,299**	**2,344**	**1,490**	**1,598**	**9,302**

The number of consumers connected to the centralised heat supply for domestic hot water in the city in 2021 was approximately half the number of those using centralised heating, totalling 5,125*. While during the summer season, heat for DHW preparation is distributed through a unified circuit to all city consumers, the breakdown of connections by each respective source/area is provided below:

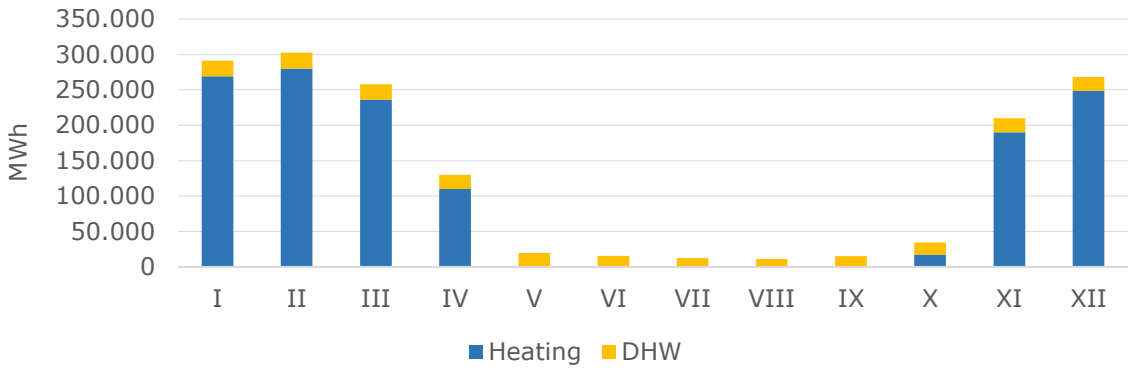
Source	Ciocana	Centru	Riscani	Botanica	Buiucani	Total
CHP Source-1 / Source-2	968	1,183	1,270	680	78	**4,179**
HOB-West	-	-	-	-	651	**651**
HOB-South	-	295	-	-	-	**295**
Total	**968**	**1,478**	**1,270**	**680**	**729**	**5,125**

In 2021, the total heat consumption in Chisinau reached 1,350,931 MWh for heating and 217,324 MWh for domestic hot water (DHW), highlighting the considerably higher energy demand for heating compared to hot water services. Combined, the total heat consumption for both heating and DHW amounted to 1,568,255 MWh.

[1] The year 2021 was analysed as a reference year for the operation of the DH system prior to the energy crisis

*Note: *This figure represents the number of "places of consumption", including building-level connections of residential buildings, educational, medical and other public buildings, economic entities; also, apartment-level connections in residential buildings with new horizontal distribution systems (with apartment-level metering), and economic entities (without separate connections) located in residential buildings.*

Heat consumption for heating and hot water supply of Chisinau consumers in 2021



The demand forecasting methodology relies on a robust analysis of historical data, which serves as a foundational reference for understanding long-term trends and seasonal fluctuations. This data is further refined by incorporating adjustments for efficiency improvements, such as the installation of individual heat substations (IHS) or pipeline upgrades. Additionally, demographic changes, including population growth and urban expansion, are factored into the projections, ensuring the forecasts remain aligned with evolving energy needs and infrastructure capabilities. This comprehensive approach ensures accurate, actionable insights for future planning, and the following Historical Adjustments and Assumptions have been utilised for forecasting future demand.

HISTORICAL ADJUSTMENTS

- **Impact of implemented IHSs during 2021-2024**

  Reduction in heat demand for heating due to the installation of IHS during the period 2021-2024 up to forecasting and, accordingly, an increase in DHW demand

- **Annual disconnection and connection of consumers during 2021-2024**

  Change in heat demand for heating and DHW due to the natural change in consumers during the period 2021-2024 up to forecasting

ASSUMPTIONS

- **Energy-efficiency measures: installation of IHS and horizontal heating systems, other EE measures in buildings**

  Reduction in heat demand for heating and increase in DHW consumers

- **Potential connection of new consumers**

  Increase in heat demand for heating and DHW due to the connection of new consumers (residential complexes and other consumers)

- **Population growth**

  Historical trend of changes in the number of residents, which potentially affects the growth in heat demand

- **Climate changes**

  Historical trend of rising external temperatures, leading to a decrease in heat demand

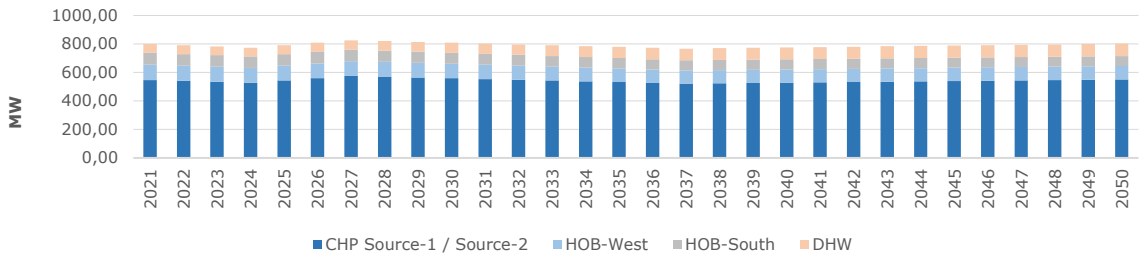
- **Laying pipelines**

  Reduction in heat loss during transportation due to the annual replacement of pipelines with a long service life

Heat Demand Projection

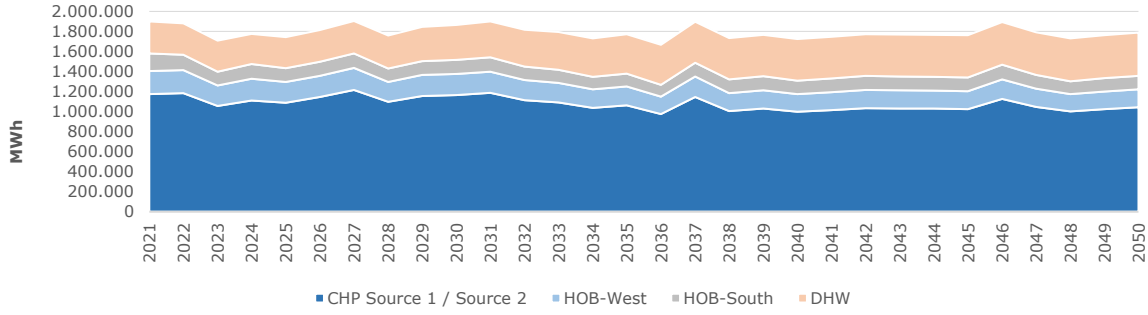
Projecting heat demand is essential for maintaining the long-term sustainability and efficiency of Chisinau's district heating system. The analysis refines baseline heat loads by incorporating consumer distribution data, seasonal variations, and urban growth trends. Adjustments for climate changes and network improvements ensure that demand projections align with infrastructure capacity. This focused approach addresses the balance between urbanisation and the need for efficient, sustainable energy solutions.

Baseline load forecast considers the influence of historical adjustments and assumptions



The transition from baseline load analysis to heat demand projections involves evaluating how evolving demographic trends, urban growth, and infrastructure improvements influence energy requirements. By establishing a strong foundation with baseline data, the model extrapolates future scenarios, accounting for factors such as climate impacts, efficiency gains, and population dynamics.

Forecast of heat energy consumption for heating and DHW in Chisinau, 2021–2050



The forecast for heat demand extends through 2050, leveraging data-driven insights to project annual and peak loads:

- **Drivers of heating demand:**
  - Climate trends: rising external temperatures and reduced heating degree days (HDDs) are expected to lower demand.
  - Population growth: increases in residential developments will offset some reductions in heating loads.
- **Peak load projections:**
  - CHP Source-1 / Source-2: experiences a slight increase in baseline load, rising by 1%, indicating stability in demand with minor adjustments over time.
  - HOB-West: registers a 12% decline in baseline load, likely driven by shifts in demand patterns and efficiency measures.

- HOB-South: shows a reduction of 14% in baseline load, following similar influences as HOB-West.
- DHW demand: significant growth of 35% by 2050 due to expanded access and improved service quality.

- **Projected outcomes:**
  - A steady decrease in network losses from 18% to 13% through pipeline replacements.
  - Balanced dynamics between declining heating demand and rising DHW needs to ensure sustainable system operations.

Heat Energy Consumers in Chisinau

Details regarding heat energy consumers in Chisinau at the beginning of 2025:

Categories of buildings	Addresses of consumption	DH connections (space heating)	DHW connections	Apartments connected to DH (space heating)	Apartments connected to DHW
Kindergartens	145	149	110		
Schools	164	189	30		
Medical institutions	76	103	28		
Higher educational institutions	99	103	22		
Residential buildings	2,835	3,893	2,128	196,587	109,815
Individual houses	261	261	10		
Economic entities	757	767	336		
Constructions	2	2	1		
TOTAL	**4,339**	**5,467**	**2,665**	**201,751**	**114,105**
Apartments with individual connections (connected to horizontal distribution systems in buildings)	5,164	5,164	4,290	5,164	4,290
Economic entities located in residential buildings		2,342	296		

1.3.4 Financial and Techno-Economic Analysis

The feasibility study examined several Combined Heat and Power (CHP) configurations to determine the most suitable solution for the modernization of Chisinau's district heating system. The objective was to replace the existing low-efficiency and with an expired operational lifespan CHP units at Source 1 and Source 2 with a new, cost-effective, and high-performance plant that ensures long-term sustainability.

Variant		Basic configuration	Maximum electrical output	Maximum thermal output	Maximum Efficiency (CHP)	Maximum Electrical efficiency (cond)	Technical minimum - MECL (electrical)
			MW	MW	%	%	MW
A	CHP type 1	2 x SGT800 + 2 x HRSB + ST	164	120	87,6	54,3	44,0

B	CHP type 2	3 x SGT800 + 3 x HRSB + ST	246	180	87,6	54,3	44,0
C	CHP type 3	1 x 9F04 + 1 x HRSB + ST	440	260	89,1	57,3	202
D	CHP type 4	3 x GT LM6000 + 3 x HRB	162	174	85,0	40,8	~0 (House Load)
E	CHP type 5	18 x Gas engines Jenbacher J920	191	185	91,0	46,5	~0 (House Load)

Each configuration was assessed based on its efficiency, investment costs, operational flexibility, and financial viability, with the aim of selecting the optimal balance between heat and electricity production.

CHP-based Cogeneration

CHP type 1 - 2 x SGT800 + 2 x HRSB + ST

- The first configuration considered was CHP Type 1, which proposed a system of two gas turbines (SGT-800), two heat recovery steam boilers (HRSB), and a steam turbine. This setup provided an electrical capacity of 164 MW and a thermal output of 120 MW, achieving an overall efficiency of 87.6%. While technically sound, its capacity was found to be insufficient to fully meet district heating demand, limiting its long-term suitability.

CHP type 2 - 3 x SGT800 + 3 x HRSB + ST

- A more advanced alternative, CHP Type 2, expanded upon this concept by adding a third gas turbine, increasing the electrical output to 246 MW and the thermal output to 180 MW, while maintaining the same efficiency level. This additional capacity made it a more suitable candidate for meeting both district heating and electricity market requirements. It also demonstrated strong financial performance, with an NPV of €250.91 million and an IRR of 11.7 %, making it the most attractive investment option in the long run.

CHP type 3 - 1 x GT 9G.04 + 1 x HRSB + ST

- In contrast, CHP Type 3 considered a single large gas turbine (GT 9G.04) combined with a heat recovery steam boiler and a steam turbine. This setup offered the highest electrical output among all configurations, reaching 440 MW, but its single-unit design posed a major operational risk. Any maintenance or unexpected outage would result in a total shutdown of power and heat production, making this option less reliable for district heating operations and for energy security. Due to its larger capacity, it delivered an NPV of 410.74 million, and IRR of 11.5 %, lower than Type 2.

CHP type 4 - 3 x GT LM6000 + 3 x HRB

- A fourth option, CHP Type 4, focused on aeroderivative gas turbines (LM 6000), offering a distributed generation approach with several gas turbines and heat recovery boilers (HRB). While this configuration provided high operational flexibility and redundancy, its overall

efficiency was lower than the other options. The financial analysis also showed higher sensitivity to fuel price fluctuations, making it less attractive from an investment perspective.

CHP type 5 - 18 Gas engines Jenbacher J920 FleXtra

- The final configuration, CHP Type 5 (Gas Engines) represents a distributed generation approach using multiple gas engine units (e.g., Jenbacher J920 Flextra) designed for flexibility and redundancy in operation. It offers highest overall efficiency, over 90 %, while electrical efficiency is lower than in case of combined cycle solutions, approximately 47 %. While its modularity allows for partial-load operation and reduces downtime during maintenance, the electrical efficiency and financial viability lower compared to CHP type 2.

Note: Specific models of gas turbines and gas engines were used for purpose of detailed analysis within the Study, however during tendering phase for new CHP unit different manufactures can compete, in accordance with specified electrical and thermal output requirements.

Complementary Technologies

The study recognizes that in addition to CHP-based cogeneration, integrating complementary technologies such as heat pumps, TES, solar thermal energy, and electrical boilers can improve operational flexibility, efficiency, and energy resilience. These systems play a crucial role in decarbonizing the district heating sector and enhancing fuel diversification.

Heat Pumps	Large-scale industrial heat pumps can utilize ambient air, ground, or waste heat from industrial processes to generate thermal energy. Although their efficiency depends on the temperature lift required, heat pumps can significantly reduce natural gas consumption in district heating. In Moldova, heat pumps would be most beneficial during shoulder seasons, when demand is lower and CHP units operate at reduced loads. Their integration with TES can further optimize their operation by allowing surplus electricity from renewable sources to be converted into stored thermal energy.
Thermal Energy Storage (TES)	The introduction of a weekly heat accumulator enables load shifting and peak shaving, improving the efficiency of CHP operations. By storing excess heat during low-demand periods and discharging it when demand increases, TES enhances system flexibility and stability. The feasibility study suggests a hot water-based TES system, which is the most cost-effective and scalable solution for integration with district heating.
Waste-to-Energy (WtE)	WtE plants can convert municipal solid waste into heat and electricity, reducing landfill use while contributing to the circular economy. With development of waste management sector in Moldova, WtE becomes essential part of waste management system while also providing a viable long-term solution for diversifying Moldova's energy mix. The main challenges include high CAPEX requirements, environmental permitting, and public acceptance, making it more suitable for future consideration as part of Moldova's waste management strategy.
Solar Thermal Systems	The potential for solar thermal collectors to supplement heat production in Chișinău is limited due to seasonal variations in solar radiation. However, integrating solar-assisted district heating could provide renewable heat during summer and transitional periods, reducing CHP fuel consumption when thermal demand is lower. The feasibility study suggests that solar thermal energy should be considered for small-scale applications, particularly for domestic hot water supply in residential and public buildings rather than for large-scale district heating.
Electrical Boilers	Electric boilers can serve as a backup or peak-load solution, utilizing excess electricity from the grid when market prices are low (particularly during periods with surplus electricity from renewable sources). While they have high operational costs compared to CHP and heat pumps, they provide instantaneous heat production and can be beneficial for stabilizing district heating operations during extreme weather events or CHP outages. Their role in Moldova's heating sector would primarily be as a supplementary or emergency heat source rather than a primary solution.

Financial and Techno-economic analysis

The feasibility study employs a detailed techno-economic model to assess the performance, costs, and financial feasibility of five different CHP configurations. The modelling framework considers technical efficiencies, capital investment, financial returns, and heat production costs, ensuring a comprehensive evaluation of each variant's viability for integration into the district heating system of Chisinau.

Each CHP configuration is evaluated based on installed electrical and thermal capacity, overall CHP efficiency, financial viability, and cost competitiveness. The results from the techno-economic model provide a clear ranking of the most feasible configurations for implementation.

CAPEX

	CHP TYPE 1	CHP TYPE 2	CHP TYPE 3	CHP TYPE 4	CHP TYPE 5
CAPEX, € million	241.18	341.82	583.42	258.86	259.05

The **capital expenditure (CAPEX)** for each variant reflects the scale and complexity of the installation:

- CHP Type 1 requires an investment of €241.18 million, making it the lowest-cost option among turbine-based solutions.
- CHP Type 2, with its larger capacity, requires €341.82 million, offering better financial returns despite a higher upfront investment.
- CHP Type 3, with its significantly larger size, requires the highest CAPEX at €583.4 million, reflecting the cost of a single high-performance gas turbine.
- CHP Type 4, requires highest specific CAPEX, in total €258.86 million, while offering poorest financial results.
- CHP Type 5, with its modular design of 18 gas-engines, requires an investment of €259.05 million, while providing good financial returns in certain scenarios.

The CAPEX specified above for each CHP type includes Thermal energy storage.

CHP Type 2 consists of three SGT800 gas turbines, three heat recovery steam boilers (HRSB), and a steam turbine, while CHP Type 5 is based on 18 gas engines (Jenbacher J920 FleXtra). **While CHP Type 5 achieves the highest overall efficiency** (91.0%), its electrical efficiency remains lower than that of CHP Type 2, which is a key factor in electricity market revenue potential. **CHP Type 2's combined cycle configuration ensures higher electrical efficiency, making it better suited for balancing heat and electricity production.**

NPV & IRR

Max electricity mode	CHP TYPE 1	CHP TYPE 2	CHP TYPE 3	CHP TYPE 4	CHP TYPE 5
NPV, € million	166.97	250.91	410.74	-144.90	79.47
IRR, %	11.3	11.7	11.5	-1.9	8.0

The financial feasibility of each option is evaluated through **Net Present Value (NPV) and Internal Rate of Return (IRR)**, which measure the project's profitability. Basic scenario for calculation of financial feasibility is maximum electricity production mode.

- CHP Type 1 achieves an NPV of €166.97 million with an IRR of 11.3%, making it a viable investment.
- CHP Type 2 significantly outperforms this, with an NPV of €250.91 million and an IRR of 11.7%, offering the best return relative to its investment.
- CHP Type 3, despite its highest efficiency, has an NPV of €410.74 million and an IRR of 11.5%, but its high investment cost reduces its relative attractiveness.
- CHP Type 4 show diminishing financial returns, with negative NPV of -€144.90 million and IRR of -1.9%, making it less favourable for large-scale district heating integration
- CHP Type 5 show positive financial returns with NPV of €79.47 million and an IRR of 8.0% in maximum electricity mode. For minimum electricity mode CHP Type 5 shows the best IRR of 11.7%, making it an attractive option for comparison with CHP Type 2.

The results confirm that **CHP Type 2 provides the best balance of financial return and investment cost**, followed by **CHP Type 5, which achieves highest efficiency and IRR in minimum electricity mode.**

Levelized Cost of Heat (LCOH)

Fuel price 50 EUR/MWh	CHP TYPE 1	CHP TYPE 2	CHP TYPE 3	CHP TYPE 4	CHP TYPE 5
LCOH, €/MWh	42.0	40.0	31.0	69.5	52.0

The **Levelized Cost of Heat (LCOH)** provides a comparison of **heat production costs under different configurations.** Basis for calculation was fuel price (natural gas + emission) of 50 EUR/MWh.

- CHP Type 1 has an LCOH of €42.0/MWh, making it relatively cost-efficient.
- CHP Type 2 has the lower LCOH at €40.0/MWh, demonstrating its strong cost-effectiveness in heat production.
- CHP Type 3 benefits from high efficiency, reducing its LCOH to €31.0/MWh, the lowest in the analysis.
- CHP Type 4 and Type 5 show significantly higher LCOH values at €69.5/MWh and €52.0/MWh, respectively, making them less economical for district heating.

The results indicate that while **CHP Type 3 achieves the lowest cost per unit of heat**, its **high capital investment cost makes it less attractive** compared to **CHP Type 2, which offers a lower LCOH while maintaining reasonable investment levels**.

Choosing the most optimal solution

The techno-economic analysis confirms that **CHP Type 2 emerges as the most optimal solution**, offering:

- A high balance of heat and electricity production (180 MW and 246 MW and, respectively).
- Competitive financial performance with an NPV of €250.91 million and an IRR of 11.7%.
- The lowest LCOH among feasible options (€40.0/MWh), ensuring long-term affordability.
- Scalability and modularity advantages, allowing for better integration with future heat storage and renewable energy sources.

CHP Type 2 strikes a balance between performance, reliability, and risk mitigation. Its ability to operate efficiently across a wide range of EL/NG price ratios makes it resilient to market uncertainties, while its modularity and alignment with thermal demand reduce operational risks. Additionally, its robust design ensures that it can continue supplying heat and electricity even during turbine outages or maintenance.

While CHP Type 5 offers high overall efficiency and operational flexibility, its lower electrical efficiency and higher reliance on heat revenues make it more sensitive to variations in electricity prices. In scenarios where heat prices remain favorable, CHP Type 5 delivers competitive returns due to its high thermal efficiency and lower electricity-to-heat ratio. However, in situations where electricity prices increase, CHP Type 2 outperforms due to its superior electrical efficiency, enabling higher electricity revenues for the same thermal output.

This dynamic makes CHP Type 2 the more balanced option, providing a stable economic return across a broader range of market conditions. Its ability to generate a larger share of electricity revenue mitigates risk in volatile energy markets, ensuring long-term financial viability and a sustainable energy supply.

With this structured investment plan, the Chisinau district heating system will undergo **a fundamental transformation**, ensuring **higher efficiency, lower operational costs, and improved reliability**. The selection of **CHP Type 2, combined with planned TES implementation**, creates a **robust foundation for future energy needs**, ensuring that the system remains **economically sustainable while supporting Moldova's long-term decarbonization goals**.

Beyond its technical and economic advantages, the new CHP is critical for strengthening Moldova's energy security. With the aging CHP Source-1 and the low-efficiency MGRES condensing power plant located in the Transnistrian region as the only significant existing sources of domestic power generation, the new CHP facility fills a vital gap in national generation capacity. It enhances grid stability and provides much-needed dispatchable power, reducing dependence on imported electricity and politically uncertain sources. Furthermore, in combination with thermal energy storage, the CHP can support the integration of variable renewable energy sources by offering balancing capacity to the power system. Its design also allows for efficient summer operation when necessary, ensuring year-round flexibility and contributing to the resilience of Moldova's energy infrastructure.

Reserve fuel storage for CHP Type 2

Recommended reserve fuel for CHP Type 2 is Diesel No.2 fuel.

A reserve fuel storage for two weeks full-load operation of CHP Type 2 requires tanks with a capacity of circa 17,000 m³ (estimated CAPEX – circa 5,0-6,0 million Euro).

The estimated CAPEX for CHP Type 2 with reserve fuel storage is circa 346,82 million Euro.

Including reserve fuel storage in the investment project for CHP Type 2 has a minor impact on the financial performance of the project, with an NPV of €247.385 million and an IRR of 11.47%.

1.3.5 Environmental and Social Assessment

The Environmental and Social Assessment (ESA) evaluates the potential environmental and social impacts associated with the construction of the new heat and power generation facilities in Chisinau, Moldova. The project integrates high-efficiency cogeneration, waste-to-energy (WtE) processes, and solar and other renewable energy sources to enhance energy efficiency and reduce greenhouse gas emissions.

Environmental Considerations

The ESA identifies key environmental concerns, primarily related to emissions control, land use, and waste management:

Air Quality and Emissions:

- The WtE plant and cogeneration facilities will generate emissions, necessitating strict compliance with national and international air quality standards.
- Advanced filtration systems and pollution control mechanisms must be deployed to mitigate negative impacts.

Water and Soil Management:

- The project will include wastewater management strategies to prevent contamination of nearby water bodies.
- Construction activities may temporarily impact soil integrity, but mitigation measures will minimize disruption. The designated land plots for the proposed constructions are intended for industrial use.
- Storage and transportation of municipal waste for WtE operations should include mitigation measures to prevent impacts on soils and groundwater

Biodiversity and Protected Areas:

- No significant impact is expected on biodiversity during operational phase, as the project is located in urban and industrial zones. Impact is limited to emergencies during construction.

Waste Management:

- The project will adopt sustainable waste handling practices, particularly for the WtE facility, to minimize landfill dependence

Social Considerations

The ESA also highlights several social aspects that must be addressed to ensure successful project implementation:

Land Acquisition and Community Impact:

- The new high-efficiency cogeneration plant (including heat storage and other associated facilities/systems) is planned on the available territory of the existing CHP Source-1, which is owned by Termoelectrica.
- In case of Waste-to-Energy plant (and eventually in case of some other complementary technologies), some land will need to be acquired/repurposed for the new energy infrastructure, requiring transparent and equitable land transactions.

- Social impact mitigation strategies will be applied to minimize disruption to local communities during construction works and operational period of the new facilities.

Stakeholder Engagement:

- An updated Stakeholder Engagement Plan (SEP) will ensure that affected communities, local authorities, and businesses are involved in decision-making processes.
- Public consultations will be conducted to address community concerns.

Occupational Health and Safety (OHS):

- Workers' safety measures will be enforced during both construction and operational phases.
- Compliance with the World Bank's Environmental and Social Standards (ESS) ensures adherence to global best practices.
- The revised ESM System and OHS policies of Termoelectrica must deliver comprehensive information to satisfy the operational requirements of the new facilities.

Mitigation Strategies

To address identified risks, the project has outlined main streams of mitigation measures for the construction and operational phases:

- **Air pollution control** through advanced filtration systems and real-time emissions monitoring.
- **Noise and dust mitigation** during construction by restricting working hours and implementing dust suppression techniques.
- **Water conservation** through proper wastewater treatment and monitoring systems.
- **Waste reduction** by promoting recycling and proper disposal of hazardous materials.

2. Introduction

2.1 Background of the project

District Heating (DH) is the primary residential heating method for around 500,000 people in Chisinau, Moldova, providing heat and hot water to various residential, public, social, and commercial entities. JSC Termoelectrica is the main company producing, transporting and supplying heat at regulated prices to consumers in Chisinau and its suburbs, and producing electricity at regulated prices.

Since 2008, the Moldovan Government has restructured the Chisinau DH sector with World Bank support. The District Heating Efficiency Improvement Project (DHEIP/P132443), approved in 2014, aimed to enhance operational efficiency and financial viability of Termoelectrica, ensuring better heating services for Chisinau residents.

With World Bank support, the DH sector in Chisinau underwent successful restructuring from 2009 to 2014, reversing a decline in services. The completed DHEIP, concluding in June 2020, paved the way for the Second District Heating Efficiency Improvement Project (DHEIP2). DHEIP2 focuses on enhancing the DH system's efficiency, supporting further improvements in service quality.

DHEIP2 is currently underway, financing key investments such as optimizing heat and electricity generation through installation of new cogeneration units, energy-efficient upgrades in public and residential buildings, including installation of modern individual heat substations. The Moldova Energy Projects Implementation Unit (MEPIU) manages the project under the Republic of Moldova's Government.

Currently, one of the main objectives of DHEIP2 is preparation of the Feasibility Study for new high-efficiency heat and power generation facilities for Termoelectrica S.A., for which assignment the Consultant has been already selected through the international competitive tendering procedure.

2.2 Purpose and scope of the feasibility study

The feasibility study aims to comprehensively evaluate the technical, economic, environmental, and social viability of constructing and operating new high-efficiency cogeneration power plants in Chisinau, aligning with national energy policies and strategic objectives to improve energy efficiency, reduce environmental impacts, and enhance energy security in Moldova. Key components of the study's scope include:

Current Energy Assessment: Detailed review of Chisinau's existing energy supply and demand, identification of gaps, and determination of the additional capacity required to meet current and future energy needs.

Technology and Configuration Evaluation: Examination of various cogeneration technologies and configurations to identify the most appropriate and efficient options for the local context. This includes analyzing the potential for incorporating renewable energy sources and innovative technologies to maximize efficiency and sustainability.

Energy Model Development: A crucial aspect of the feasibility study is the creation of an energy model. This model will simulate the operation of the proposed cogeneration plant within the broader heat and electricity generation system of Chisinau. It will account for all technical and economic characteristics of generation units, such as nominal power, fuel costs, and variable operating costs, with a time resolution of one hour. The optimization criterion will focus on maximizing the total profit from the cogeneration plant, considering all variable costs and revenues. This model will facilitate the evaluation of the plant's integration into the existing energy infrastructure, its efficiency in meeting heat and electricity demands, and its flexibility in response to fluctuating energy prices and demand patterns.

Financial Analysis of Termoelectrica S.A.: A detailed financial analysis of Termoelectrica S.A. is paramount. This encompasses an in-depth review of the company's current financial health, including profitability, cash flow, and balance sheet analysis, to establish a baseline for assessing the financial implications of integrating the new high-efficiency cogeneration power plant. The analysis will also project the plant's potential financial impact on Termoelectrica's future revenue streams, cost structures, and overall financial sustainability. By evaluating the economic viability of the project in the context of Termoelectrica's financial ecosystem, the study aims to ensure that the proposed investment not only aligns with the company's strategic objectives but also enhances its financial stability and growth prospects in the competitive energy market.

Financial and Economic Analysis: Projection of the project's financial feasibility, encompassing capital investment, operational expenses, potential revenues, and economic benefits. This analysis will assess the cost-effectiveness of the proposed cogeneration plant and its impact on the local economy.

Environmental and Social Impact Assessment: Evaluation of the project's potential environmental and social impacts, ensuring compliance with national and international, as well as Word Bank standards. This assessment will address the project's sustainability and propose measures to mitigate negative impacts while enhancing positive outcomes.

Implementation Plan Development: Formulation of a detailed project implementation strategy, including timelines, resource allocation, and risk management strategies. This plan will outline the steps required to bring the cogeneration plant from concept to operation, ensuring a smooth and timely project execution.

2.3 Electricity System of the Republic of Moldova[2]

In 2023, the total electricity consumption in the Republic of Moldova on the right bank of the river Dniester was approximately 4,333 million kWh. This figure reflects the ongoing energy demands in the country, which experiences significant fluctuations in electricity usage depending on the season. Notably, the electricity system faced peak loads exceeding 1,000 MW during both the winter and summer months, with the summer of 2024 also recording similar high demands, highlighting the critical nature of energy management in extreme weather conditions.

On the right bank of the Dniester River, the peak load recorded for the winter of 2023 was 760 MW, while during the summer, it dropped slightly to 700 MW. In contrast, the Transnistrian region exhibited peak loads of 250 MW in winter and a marginally higher 260 MW in summer. These figures illustrate the regional variations in electricity demand within the country. The consumption of electricity by final consumers on the right bank amounted to about 3,889 million kWh in 2023, which indicates a decrease from the previous year's consumption of 4,051 million kWh in 2022. This decline may signal shifts in energy efficiency or changes in economic activity and consumer behavior.

The internal sources of electricity production in Moldova (on the right bank of the Dniester river) are largely dominated by the urban district heating power plants operated by Termoelectrica JSC and CET Nord JSC. Together, these facilities contributed 59.7% of the total domestically produced electricity on the right bank, accounting for 603.4 million kWh. Additionally, wind power plants played a significant role, supplying 18.9% of the total production, which corresponds to 191.3 million kWh. Photovoltaic power plants contributed 13.1% or 132.3 million kWh, while biogas power plants accounted for 1.4% (13.8 million kWh). Furthermore, district heating power plants associated with sugar factories provided a minor yet notable 0.1% of the electricity generated locally. The Costesti hydroelectric power plant added to the renewable energy mix with a 6.8% share of domestic

[2] This chapter is based on the document: Action plan for emergency situations in the electricity sector, by the Government of the Republic of Moldova - Ministry of Energy of the Republic of Moldova 2024, https://www.energy-community.org/dam/jcr:36f269a7-1c07-4e48-b004-1313525440e0/Moldova%20Action%20Plan%20for%20emergency%20situations%20in%20the%20electricity%20sector%20-%20Final%20draft.pdf

production on the right bank. When combined with other renewable energy sources, these facilities collectively provided approximately 10.4% of the total electricity consumption during 2023, emphasizing the growing importance of renewable energy in Moldova's energy landscape.

In terms of electricity imports, there was a reduction of 497.8 million kWh in 2023. This decrease was compensated by an increase in electricity generated by local producers, including the contributions made by consumer power plants that supply electricity directly to the grid, but mainly by purchase of more electricity from the Moldavskaya GRES (MGRES) thermoelectric power plant, located on the left bank in Transnistrian region. The total amount of electricity purchased from MGRES in 2023 reached about 3,279 million kWh, representing an increase of 572.2 million kWh compared to the previous year.

Additionally, it is important to note that the Government Decision No. 125/2024 has designated "Operatorul Pietei de Energie M" Limited Liability Company as the official operator of the electricity market in Moldova. This organization is responsible for the creation and operation of organized electricity markets, which will play a crucial role in facilitating transactions, ensuring fair pricing, and promoting competition within the energy sector. As Moldova continues to navigate its energy challenges, the establishment of a structured market may lead to improved efficiency and sustainability in electricity distribution and consumption.

Table 2-1. Quantities of electricity produced, imported and delivered to final consumers on the right bank in 2023, million kWh

No	Indicator	Quantity
1	**Electricity purchased, total, including:**	**4,333.1**
2	Termoelectrica JSC	524.6
3	CET Nord JSC	78.9
4	SE NHE Costesti	68.8
5	Renewable producers	337.4
6	Other local producers	1.4
7	MGRES	3,278.5
8	Import from Ukraine	10.1
9	Import from Romania	240.4
10	Electricity transmission network losses	196.6
11	Electricity distribution network losses FOE Premier Energy Distribution JSC	223.9
12	Electricity distribution network losses RED Nord JSC	69.1
13	**Delivered to end consumers, total, including:**	**3,889.0**
14	FOE Premier Energy JSC	2,870.8
15	FEE Nord JSC	1,006.2
16	Other suppliers	12.0
17	**Electricity consumption by final consumers:**	**3,889.0**
	- *Household consumers*	*1,613.7*
	- *Non-household consumers*	*2,275.2*

Starting from 01.01.2025, MGRES, which was previously the main electricity generation source for the Republic of Moldova, stopped electricity supply to the right bank. It had to be replaced with considerable electricity imports from Romania.

2.3.1 Description of the Electricity System of the Republic of Moldova

Electricity plays an indispensable role in the energy framework of the Republic of Moldova, accounting for approximately 14% of the country's total final energy consumption. This positions electricity as the fourth largest energy source, following oil products, biofuels, and natural gas. Its significance extends beyond mere consumption figures; electricity is a fundamental driver of the national economy, influencing a wide array of daily activities and quality of life for citizens. Therefore, ensuring the reliability, affordability, and sustainability of electricity sources is of paramount importance for fostering economic growth and enhancing the overall well-being of the population.

The electricity system in Moldova is uniquely structured, divided between the right and left banks of the Dniester River. This division presents specific challenges, particularly because the left bank operates under a different political and administrative framework, not fully controlled by the country’s constitutional authorities.

To effectively manage the electricity system, there is collaboration between the State Enterprise Moldelectrica and enterprises in the Transnistrian region, involving coordinated activities that include real-time exchanges of operational data between dispatchers, joint efforts during emergency situations, and collaboration for the maintenance and modernization of infrastructure. These coordinated efforts play an important role in ensuring a continuous electricity supply and minimizing potential disruptions in the system.

The largest power-generating source in the region is the Moldavskaya GRES (MGRES) thermoelectric power plant, which is located on the left bank and is not controlled by the constitutional authorities of the Republic of Moldova.

For decades, MGRES has been the main source of electricity supply in the region, generating approximately 80% of the electricity consumed on the right bank while also providing power to the left bank. The significance of this power plant could not be overstated, as it was central to the energy security of the region. However, starting with January 1, 2025, MGRES stopped the supply of electricity to the right bank.

The electricity generation in Moldova on the right bank relies on domestic sources, which include Combined Heat and Power (CHP) plants. These facilities are particularly efficient, as they generate both electricity and heat from a single fuel source. However, the existing CHPs are aging and need to be replaced with modern high-efficiency CHPs.

Moreover, the country is increasingly turning to renewable energy options, such as wind, solar, and hydropower, reflecting a commitment to diversify its energy mix and reduce dependence on fossil fuels. This shift toward renewables is not only environmentally beneficial but also enhances energy security and sustainability.

The electricity sector in Moldova encompasses a range of regulated activities critical to its functionality. These include the operation of the electricity market, the transmission of electricity through various networks, centralized management of the electricity system, distribution to end-users, and the overall supply of electricity to consumers. Each of these components is essential for ensuring that electricity is generated, transmitted, and delivered efficiently, thereby supporting economic activities and improving the quality of life for citizens.

As Moldova looks to the future, several significant regulatory changes are on the horizon. The country is preparing to transpose The Electricity Integration Package into its national legislation, which aims to modernize the electricity sector and enhance operational efficiency. Among the key activities to be regulated following these changes are energy storage solutions, which will allow for better management of supply and demand dynamics, and the aggregation of electricity resources. These

initiatives will facilitate a more integrated and flexible electricity market, enabling greater participation from various stakeholders.

The anticipated reforms will not only improve the efficiency of the electricity system but also contribute to its resilience. By enhancing infrastructure and regulatory frameworks, Moldova aims to better navigate the complexities of the modern energy landscape. In summary, the electricity system in the Republic of Moldova is a complex and multifaceted network that plays a crucial role in the nation's economy and daily life. With ongoing efforts to improve reliability and sustainability, combined with strategic partnerships and forthcoming regulatory reforms, Moldova is well-positioned to address the challenges of the future and ensure a secure and sustainable energy supply for its citizens.

2.3.2 Electricity Generation

Electricity generation in the Republic of Moldova, the power plants located on the right bank of the Dniester river currently provide approximately 20% of the country's annual electricity demand. This very limited contribution highlights the ongoing challenges faced by Moldova in achieving energy independence and reliability.

The landscape of local electricity production on the right bank is primarily shaped by two major urban heating enterprises: Termoelectrica JSC and CET Nord JSC, operating combined heat and power plants. Together, in 2022, these facilities accounted for 71.8% of the total electricity generated on the right bank, translating to around 611.6 million kWh. This underscores the importance of these plants in meeting the country's energy needs, considering the availability of useful heat demand, and the opportunity to implement new high-efficiency cogeneration plants to replace the old low-efficiency facilities.

In addition, various renewable energy sources played a significant role in the overall mix, with wind power contributing 16.8% (143 million kWh), photovoltaic solar energy providing 3.6% (30.3 million kWh), biogas plants adding 2.8% (23.6 million kWh), and district heating from sugar factories making up a small fraction at 0.2%.

Among the renewable energy producers, SE "Nodul Hidroenergetic Costesti" hydropower plant contributed 6.8% to the total internal electricity generation. When combined with other renewable sources, the cumulative contribution reached approximately 10.4% of final electricity consumption. This growing reliance on renewable energy reflects a broader trend towards sustainable energy solutions within the region.

The total installed capacity for electricity generation in Moldova, excluding the contentious Transnistrian region, stands at about 727 MW. This capacity is distributed across various power plants:

1. **Termoelectrica JSC** in Chisinau has an installed electrical capacity of 324 MW, derived from two combined heat and power (CHP) units:

    - **CHP Source 1**, established between 1976 and 1980, has an output of 258 MW and utilizes primarily natural gas, and may use heavy fuel oil as reserve fuel. However, all three generating units have exceeded their original operational lifetime, and will need to be replaced in the near future with new high-efficiency cogeneration plant (which is examined under the present Feasibility Study).

    - **CHP Source 2**, built **from** 1951 to 1961, has installed capacity of 66 MW and primarily operates on natural gas. However, most of the installed capacity is not available anymore. This plant is planned to be closed down as soon as new high-efficiency cogeneration plants based on gas engines (with electrical capacity of circa 55 MW) will be installed under the DHEIP-2 project.

2. **CET Nord JSC**, located in Balti, has an installed capacity of 37 MW, functioning with natural gas, and was constructed between 1956 and 1970. New cogeneration units based on gas engines with total electrical capacity of circa 13.4 MW were installed recently.

3. The **Costesti-Stanca Hydroelectric Power Plant (HPP)** contributes 16 MW and was established in 1978.

4. Renewable energy sources collectively account for 350.31 MW, which encompasses:

    - Biogas power plants with a total capacity of 6.86 MW.
    - Wind power facilities contributing 122.5 MW.
    - Photovoltaic solar power plants, which have a total capacity of 220.95 MW.

5. Lastly, other power plants, including those associated with sugar factories, with additional 87 MW installed capacity, having been built between 1956 and 1981. However, they are mostly non-operational.

It is important to emphasize that, despite the total installed power capacity on the right bank being 727 MW, a significant portion of this capacity—almost half—is currently non-operational. This is primarily because the equipment in use is outdated and has not undergone necessary refurbishment or modernization.

In contrast, the electricity generation capacity within the Transnistrian region is significantly higher, amounting to 2,600 MW. This includes:

1. MGRES thermoelectric power plant with an installed capacity of 2,520 MW, constructed between 1964 and 1982. This facility primarily uses natural gas but has the capability to switch to fuel oil or coal as alternative fuels. MGRES is an aging power plant with efficiency considerably lower than modern high-efficiency thermal power plants. It operates in condensing mode, wasting most of the produced heat in the environment.

2. The **Dubasari Hydroelectric Power Plant (HPP)**, with an installed capacity of 48 MW, was built between 1954 and 1966.

3. The **Tirotex CHP**, which adds 31 MW to the total capacity.



Figure 2-1. Power grids and power plants in the Republic of Moldova

Before January 1, 2025, for decades the natural gas supply for MGRES thermal power plant was sourced from Gazprom PJSC. During the last years, the entirety of the 5.7 million m³/day of natural gas supplied to Moldova was allocated by Moldovagaz JSC to meet the energy needs of the left bank and to facilitate electricity generation by MGRES for the right bank.

MGRES was selling electricity at a competitive price, leading to the assumption that the fuel (natural gas) cost for electricity generation was considerably below the market price. This situation led to the accumulation of a large debt of the Transnistrian region for the natural gas supplied from Gazprom.

On 01.01.2025 the natural gas transit from Russia through Ukraine stopped, and considering that Gazprom did not continue to supply of natural gas to the Transnistrian region using an alternative route, MGRES no longer delivers electricity on the right bank.

During the gas crisis on the left bank in the first months of 2025, the Transnistrian region failed to accept purchasing of natural gas at market prices, and operated MGRES at low capacity based on a limited reserve of coal, and only for the needs of the left bank.

To be noted that at market prices for natural gas, considering the technology, the price of electricity from MGRES would be considerably higher than the price from a modern high-efficiency plant.

Republic of Moldova on the right bank replaced the electricity formerly procured from MGRES with electricity imported from Romania. This became possible after the synchronization of the Ukrainian and Moldovan power systems with ENTSO-E in 2022.

The situation is compounded by the fragility of import routes, especially given the extensive damage inflicted on Ukraine's energy infrastructure as a result of bombardments during the war. The critical state of Ukraine's energy facilities necessitates substantial electricity imports (including transit via Republic of Moldova), further straining regional supply chains.

Although Republic of Moldova is interconnected with the Ukrainian power system, considering the massive destruction of the power generation plants in Ukraine during the war, and the deficit of electricity in the neighbouring country, Ukraine does not have possibilities to export electricity to the Republic of Moldova.

2.3.3 Electricity Transmission

According to Law No 107/2016 concerning electricity, the infrastructure utilized for the transmission of electricity is defined as electricity transmission networks. This includes high-voltage power lines, which are essential for transporting electrical energy over long distances. Additionally, this definition encompasses various components such as transformers, switching equipment, machinery, and auxiliary installations that support the overall functionality and efficiency of the transmission system.

In the Republic of Moldova, the management and operation of the electricity transmission network is carried out by SE Moldelectrica. Besides, this organization plays a crucial role in ensuring the centralized management of the entire electricity system within the country, coordinating activities to maintain stability, efficiency, and reliability of electricity supply.

The electricity grid in Moldova is extensive, comprising a total of 6,228.6 kilometers of transmission lines. These lines operate at different voltage levels, specifically 400 kV, 330 kV, 110 kV, and 35 kV. This diverse array of transmission lines is vital for facilitating the transmission and distribution of electricity across various regions, thereby ensuring that consumers have access to a reliable power supply. The intricate network of high-voltage lines is essential not only for meeting current energy demands but also for supporting future growth and development in the energy sector of Moldova.

Table 2-2. Key elements of the electricity transmission network

Voltage level (kV)	Lines			Transformers	
	Length (km)	Number	Capacity (MW)	Number (unit)	Capacity (MW)
In the transmission system					
400 330 110 35 **Transmission – total**	203,0 377,34 3.337,04 807,59 **4.724,97**	1 3 131 -	500.0 1.525,0 2.365,7 -	650	4.641,5

Note: Under the administration of SE Moldelectrica

In the Republic of Moldova, the electricity transmission infrastructure plays a crucial role in connecting various consumers and power generation facilities. Currently, there are 105 final consumers classified as non-household users linked to the electricity transmission grids. Additionally, the network encompasses 20 power plants, of which 5 are associated with sugar producing facilities. Notably, 9 of these power plants harness renewable energy sources, contributing to a more sustainable energy mix within the country.

The responsibility for the operation, maintenance, modernization, and development of the electricity transmission networks falls to SE Moldelectrica. This entity serves as the sole operator of the electricity transmission system in Moldova. In this capacity, SE Moldelectrica not only ensures the efficient functioning of the transmission networks but also addresses various challenges related to granting access to the electricity grid. This includes overseeing the process of connecting new users to the electricity transmission networks, which is vital for expanding the grid's reach and accommodating future energy demands.

Electricity transmission activities are performed under a specific license that authorizes the operator to carry out these essential functions. Furthermore, in accordance with Law No 107/2016 on

electricity, the transmission system operator that holds this license is tasked with the centralized management of the electricity system. This involves a comprehensive approach to operational-technological management, ensuring that the electricity supply remains balanced and reliable. By fulfilling these obligations, SE Moldelectrica plays a key role in maintaining the stability and efficiency of Moldova's electricity infrastructure, ultimately supporting the country's energy objectives and contributing to its economic development.

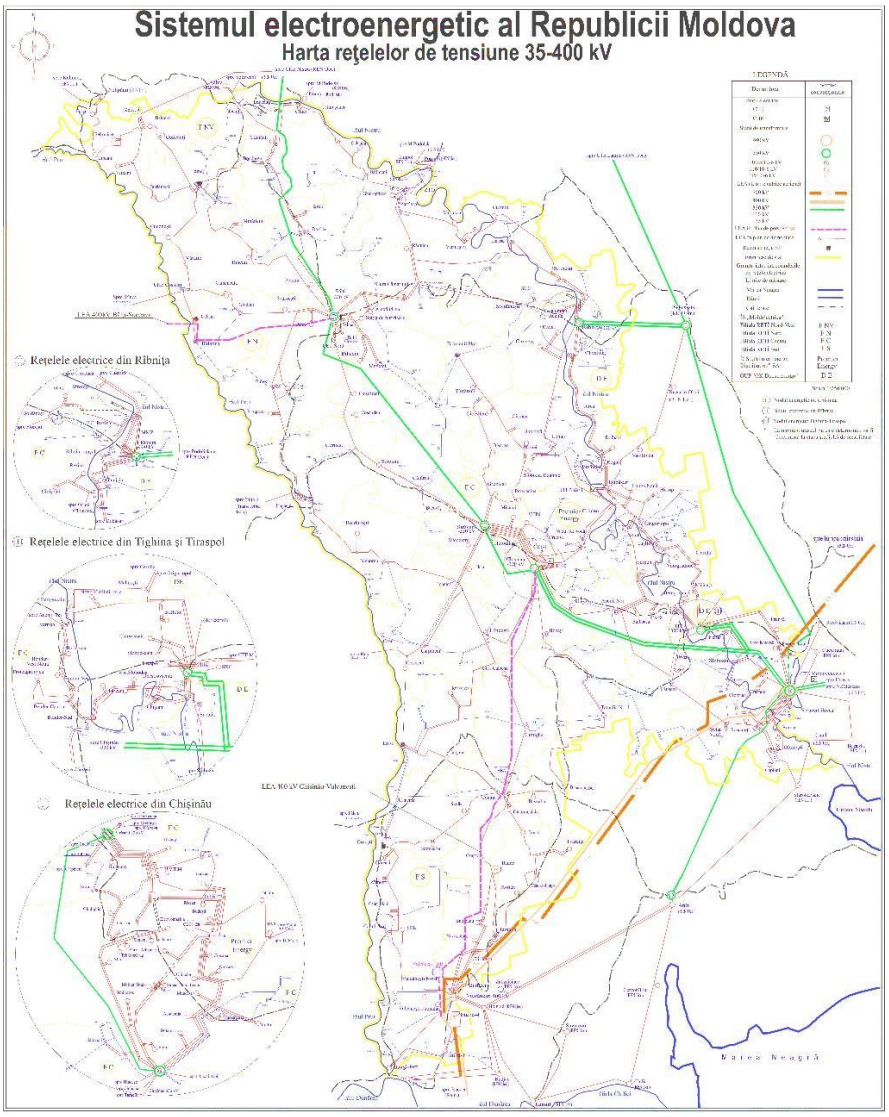


Figure 2-2. Electricity system of the Republic of Moldova (Map of electricity networks)

The power system of the Republic of Moldova, which encompasses the Transnistrian region, is intricately interconnected with Ukraine's electricity grid. This connection is facilitated through a total of 21 power lines, comprising 7 overhead lines that operate at a nominal voltage of 330 kV and 12 additional overhead lines functioning at 110 kV. These interconnections play a crucial role in enabling the simultaneous transmission of electricity between the Republic of Moldova and Ukraine, allowing for both import and export activities while operating in synchronous mode. This synchronization is vital for maintaining stability and reliability in the electricity supply for both nations.

In addition to its connections with Ukraine, the power system of the Republic of Moldova is also linked to that of Romania. This is achieved through a significant 400 kV overhead power line known as Vulcanesti-Isaccea, alongside four 110 kV lines. These high-voltage interconnections not only

enhance the electricity trading capabilities of Moldova but also contribute to the overall regional energy security.

However, a significant development occurred on February 24, 2022, when the electricity systems of Ukraine and the Republic of Moldova were decoupled from the integrated IPS/UPS system. This separation was crucial given the geopolitical tensions and circumstances affecting the region. In response to this situation, on March 16, 2022, the Transmission System Operators (TSOs) of Continental Europe took swift action to facilitate the emergency synchronization of the ENTSO-E European Continental Energy System with the electricity systems of both Ukraine and the Republic of Moldova. This emergency measure aimed to restore stability and ensure a reliable power supply in the face of unprecedented challenges, highlighting the importance of international cooperation in the energy sector during times of crisis.

Table 2-3. Transfer capacities of interconnections with electricity systems of neighbouring countries

Direction of electricity flow	Until the allocation of cross-border capacity at the Ukraine-Hungary border, MW	After the allocation of cross-border capacity at the Ukraine-Hungary border, MW
UA > MD	0	0
MD > UA	800	800
RO > MD	600	315
RO > MD	200	82

Currently, the management of access to the electricity interconnections between the Republic of Moldova and Ukraine is overseen by NEK Ukrenergo, which serves as the designated transmission system operator for Ukraine. This arrangement specifically pertains to the import of electricity from Ukraine, which is crucial for meeting Moldova's energy demands, especially during periods of high consumption or shortages. On the other hand, the interconnections between Moldova and Romania, particularly those related to electricity imports from Romania, are managed by Transelectrica, the National Company for Electricity Transmission in Romania. This dual management structure underscores the importance of international cooperation in ensuring energy security and reliability for both Moldova and its neighboring countries.

From a technical perspective, the electricity transmission networks currently operating within Moldova are generally in satisfactory condition. They provide a continuous and reliable supply of electricity to consumers, which is essential for both residential and commercial operations. This reliability is particularly important in today’s context, where the demand for electricity is constantly increasing due to various factors, including population growth, urbanization, and technological advancements. However, despite this satisfactory operational status, there exists a pressing need for modernization of these electricity networks. The lack of adequate funding sources has led to stagnation in network development, hindering potential upgrades and improvements that could significantly enhance efficiency, capacity, and overall service quality.

The ongoing war in Ukraine has had a profound impact on the energy landscape in the region, exacerbating existing challenges and creating new ones. Since October 2022, the war has led to a marked increase in energy shortages, which have had serious ramifications for both consumers and businesses in Moldova. These shortages have resulted in temporary interruptions in electricity supply during peak consumption periods, creating significant inconvenience and uncertainty for end users. The situation has been further compounded by substantial increases in electricity prices, which have surged dramatically - nearly quadrupling over the course of 2022. This substantial rise in prices has triggered a ripple effect, causing price hikes across various sectors, including heating, manufacturing, and services, further straining the economic landscape and impacting the cost of living for citizens.

In light of these challenges, the situation was managed through the activation of a contingency contract between SE Moldelectrica and Transelectrica. This agreement allowed for a coordinated response to the energy crisis, enabling both countries to use available resources more effectively. Additionally, the state-owned enterprise Energocom JSC registered with the electricity market operator OPCOM, facilitating the procurement of electricity from the Romanian electricity exchange. This strategic move was essential for stabilizing the supply and mitigating the impact of energy shortages on consumers, ensuring that essential services could continue to operate despite the challenging circumstances.

Despite the synchronous operation of Moldova's electricity system with the ENTSO-E (European Network of Transmission System Operators for Electricity) system, the existing interconnections with the European grid are insufficient for ensuring the stability and security of the overall system. This inadequacy poses significant challenges in balancing electricity demand and supply effectively, especially during periods of high consumption or unexpected outages. A fully functional interconnection between Moldova, ENTSO-E, and Ukraine necessitates a comprehensive strengthening of the electricity transmission network. This enhancement requires not only the construction of additional overhead power lines within Moldova but also improved connections to the electricity systems of Romania and Ukraine, which are critical for facilitating smoother and more reliable electricity flow.

To bolster the electricity infrastructure with Romania, several ambitious plans are in place to construct three significant 400 kV interconnections:

1. **Isaccea (Romania) – Vulcanesti – Chisinau (Republic of Moldova)**: This project is currently in progress and is anticipated to be completed by 2025. It represents a crucial step in enhancing the capacity and reliability of the electricity supply between the two nations. The successful completion of this interconnection will not only improve the electricity supply but also foster greater energy cooperation and integration between Moldova and Romania.

2. **Suceava (Romania) – Balti (Republic of Moldova)**: For this interconnection, the feasibility study has been successfully completed. Additionally, both environmental and social impact assessments have been conducted, and the necessary financial resources have been allocated to move forward with the project. This careful planning ensures that the project aligns with sustainability goals while addressing the pressing energy needs of Moldovan consumers.

3. **Gutinas (Romania) – Straseni (Republic of Moldova)**: This interconnection is also part of the strategic plans to strengthen Moldova's electricity links with Romania, further enhancing overall network resilience and capacity. By connecting more robustly with Romania, Moldova can leverage its neighbor's energy resources more effectively and provide a more stable supply to its citizens.

Furthermore, in an effort to improve electricity connections with Ukraine, there are plans to increase the capacity of the existing 330 kV interconnection between Balti in Moldova and Dnestrovsc in Ukraine. This expansion is critical for facilitating more efficient electricity flow and enhancing the stability of the interconnected systems. Such improvements are essential not only for meeting current energy demands but also for preparing the grid for future challenges, including the integration of renewable energy sources and the anticipated growth in.

2.3.4 Electricity Distribution

The electricity distribution networks situated on the right bank of the Dniester River comprise a vast infrastructure that extends over a total length of 56,993 kilometers. This extensive network is categorized into different voltage levels to effectively manage the distribution of electricity to various consumers. Specifically, it includes approximately 1,800 kilometers of high voltage power lines operating at 35 to 110 kV, which are essential for transmitting electricity over long distances with minimal losses. In addition, the network features around 21,414 kilometers of medium voltage lines functioning at 6 to 10 kV, designed to deliver power to substations and larger consumers. Finally,

there are about 33,300 kilometers of low voltage lines, operating at 0.4 kV, which are primarily responsible for supplying electricity directly to residential and small commercial users.

The network is equipped with a total of 15,288 electric transformers, which collectively have a substantial capacity of 4,712.88 MVA. These transformers play a critical role in stepping down the voltage levels to ensure safe and reliable electricity supply to end-users.

In terms of generation, the electricity distribution networks have 85 power plants connected to them. Notably, 83 of these facilities utilize renewable energy sources, which reflects a significant commitment to sustainable energy practices. Additionally, the distribution network supports 1,432,000 electrical installations for final consumers, all of which are equipped with metering devices. This infrastructure means that approximately 1,284,800 final consumers receive electricity through these networks. Among these consumers, a large majority – 1,226,400 individuals or about 95.45% – are classified as household users, highlighting the networks' crucial role in providing energy for everyday domestic needs.

The operation, maintenance, modernization, and development of these electricity distribution networks are managed by two licensed distribution system operators, each playing a vital role in ensuring the reliability and efficiency of the electricity supply:

1. **FOE Premier Energy Distribution JSC**: This operator is responsible for approximately 939,400 sites of consumption and generation, which accounts for about 65% of the total number of sites in the country. FOE Premier Energy Distribution JSC covers roughly 70% of the territory of the Republic of Moldova, excluding the Transnistrian region. Their extensive coverage allows them to serve a significant portion of the population and various commercial entities throughout the region.

2. **RED Nord JSC**: This operator oversees around 492,600 sites, representing 35% of the total consumption and generation points within the country. RED Nord JSC focuses on providing efficient service to its designated areas, ensuring that consumers receive a reliable electricity supply.

In recent years, both operators have encountered challenges due to adverse weather conditions that have significantly impacted the performance of the electricity distribution networks. In 2023, these networks experienced more severe disruptions compared to the previous year, highlighting the vulnerability of infrastructure to climatic events. For instance, RED Nord JSC reported a dramatic increase in the System Average Interruption Duration Index (SAIDI) for interruptions caused by special weather conditions. This figure rose from 26.07 minutes in 2022 to an alarming 294.1 minutes in 2023, indicating a substantial deterioration in service reliability.

Similarly, FOE Premier Energy Distribution JSC faced a comparable situation, with the SAIDI value for outages attributed to extreme weather increasing from 34.09 minutes in 2022 to 207.7 minutes in 2023. These increases underscore the critical need for improved resilience and adaptability in the face of climate-related challenges.

On a more positive note, RED Nord JSC experienced a significant decrease in the SAIDI value for outages caused by third parties or user installations, which fell from 249.6 minutes in 2022 to 59.4 minutes in 2023. This suggests that while weather-related disruptions have escalated, the operator has effectively managed to reduce the impact of external factors on service reliability.

Conversely, FOE Premier Energy Distribution JSC noted an increase in outages attributed to third parties, with SAIDI rising from 95.07 minutes in 2022 to 101.6 minutes in 2023. This trend highlights the ongoing need for collaboration and coordination among various stakeholders to mitigate the impact of such interruptions on the overall electricity supply.

In summary, the electricity distribution networks on the right bank of the Dniester River represent a complex system that plays an essential role in delivering power to a diverse range of consumers. While the networks face challenges, particularly from adverse weather conditions, the commitment

of the distribution system operators to maintain and improve service quality remains crucial for ensuring a reliable and sustainable electricity supply in the region.

2.4 Site Investigation and Current Situation

The district heating system (DHS) in Chisinau originated in 1946 with the development of the city's first technical project for heat supply. This pioneering project introduced a cogeneration system that simultaneously produced heat and electricity, significantly enhancing energy efficiency and optimizing resource utilization. The initial thermal power plant, designated as **CHP-1 (CET-1)**, was commissioned in September 1951 and is currently known as **CHP Source 2** under the management of Termoelectrica.

Chisinau's complex terrain, characterized by its location across seven hills, presented substantial engineering challenges in designing an effective DHS. To maintain consistent pressure and flow rates throughout the network, the system was divided into independent hydraulic zones. This configuration necessitated the construction of **17 pumping stations** strategically positioned to manage these zones efficiently. The main heating distribution pipelines extend over **269 kilometres**, forming the backbone of the DHS by transporting thermal energy from the central plants to various districts, up to the DH substations. Additionally, there are circa **260 kilometres** of DH networks from central substations to buildings. Besides, there circa **180 kilometres** of pipes supplying domestic hot water from central substations to residential and other buildings, ensuring year-round comfort for residents.

Termoelectrica is gradually excluding the central substations and installing modern individual heat substations (for heating and DHW) in each building. Currently there are already more than 1000 modern IHSs installed in buildings, ensuring improved quality and efficiency of services. After IHSs are installed, the primary DH pipes are connected to the IHS in the building, and the external DHW pipes are excluded (the DHW being prepared in the IHSs in the building).

In 1976, to meet the escalating energy demands of the city, a second combined heat and power plant was commissioned. Initially known as **CHP-2 (CET-2)** and now, as a part of Termoelectrica, referred to as **CHP Source 1**, this facility is connected to CHP Source 2 via a **1000 mm diameter heating pipeline** originating from Pump Station No. 8. Upon its commissioning, CHP Source 1 became the largest thermal power plant in Chisinau, with a total installed electrical capacity of **240 MWe** and a heat capacity of **1,200 Gcal/h**.

The plant was equipped with advanced technology for its time, including high-efficiency boilers and turbines capable of operating on multiple fuel types, enhancing operational flexibility.

From 1990, the centralized heating system was managed by the municipal Joint Stock Company "**Termocom"**. However, due to financial difficulties and infrastructural challenges, bankruptcy proceedings were initiated in 2015. Subsequently, **Termoelectrica SA** was established as a new joint-stock company, consolidating the assets and operations of CHP Source 1, CHP Source 2, and Termocom. Termoelectrica SA has since become the main heat producer and supplier for Chisinau and its surrounding areas, playing a pivotal role in meeting the energy needs of both residential and industrial consumers.

In addition to the primary CHP plants, Termoelectrica operates two significant heating plants within the Chisinau municipality: **CT-SUD (HOB South)** and **CT-VEST (HOB West)**. CT-SUD is located in the southern part of the city and contributes substantially to meeting heating demands, especially during peak periods in winter. CT-VEST, situated in the western region, serves a similar role, enhancing the capacity and redundancy of the overall system. Furthermore, Termoelectrica manages **nineteen heating plants** distributed throughout the suburbs of Chisinau. These facilities are essential for addressing localized heating requirements, particularly in areas where extending the main DHS may not be economically feasible or technically practical.

2.4.1 Current State of the System and Existing Production Units

The district heating system (DHS) in Chisinau has evolved significantly over the years, combining both legacy infrastructure and modern upgrades. The main DH network of the city of Chisinau can be seen in the following figure.

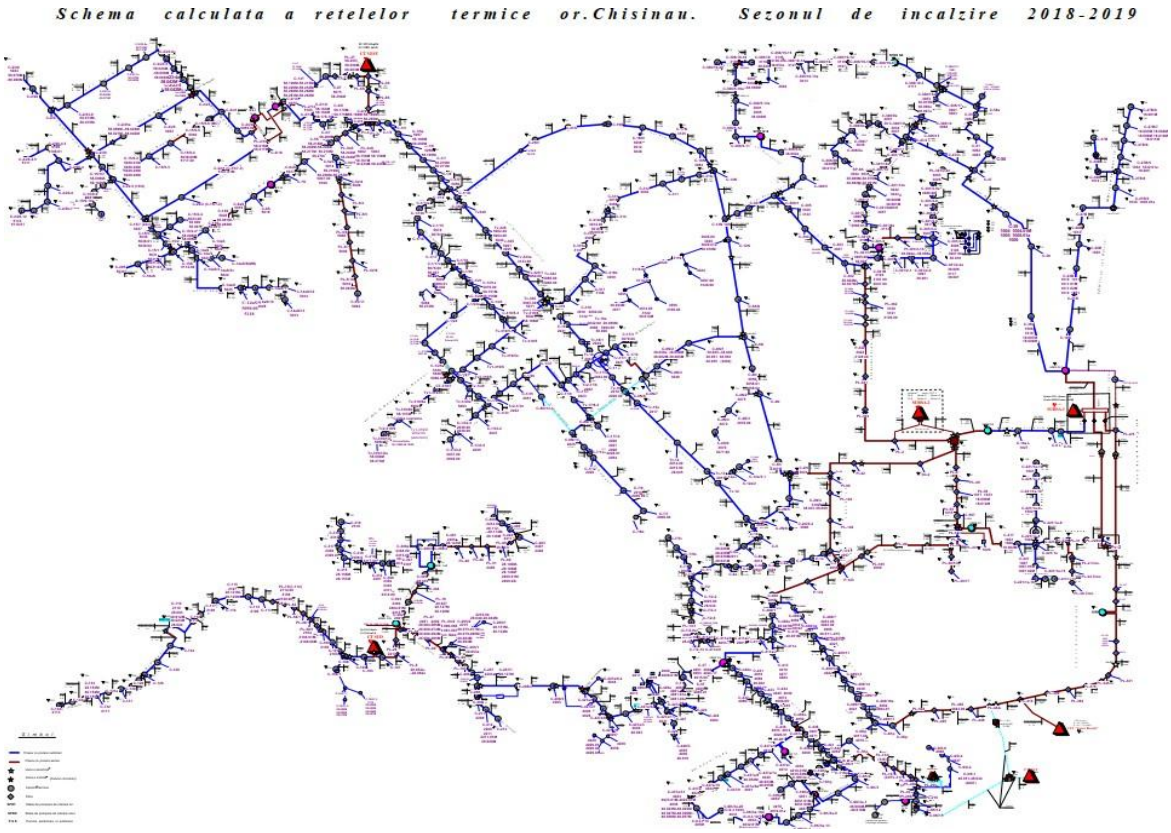


Figure 2-3. DHS system in the city of Chisinau

Due to recent revitalization efforts, the DHS is now a blend of older, deteriorated pipelines and newer, pre-insulated district heating pipes. Considering that the expected lifespan of these pipes is approximately 30 years, it's important to note that around **51.5%** of the network's pipes have exceeded their technical lifetime. This aging infrastructure poses challenges in terms of efficiency and reliability.

To address this, the investment strategy focuses on systematically replacing all pipes that are over 40 years old. This proactive approach aims to reduce the risk of failures and improve the overall performance of the network. Despite the aging components, the system is well-maintained, resulting in relatively low heat and water losses when compared to similar district heating systems in the region.

The heat supply for Chisinau's DHS is based on four main production plants:

1. **CHP Source 1** (CET Sursa 1)
2. **CHP Source 2** (CET Sursa 2)
3. **HOB West** (CT Vest)
4. **HOB South** (CT Sud)

These plants are strategically located throughout the city to optimize heat distribution, as it can be seen on following figure.

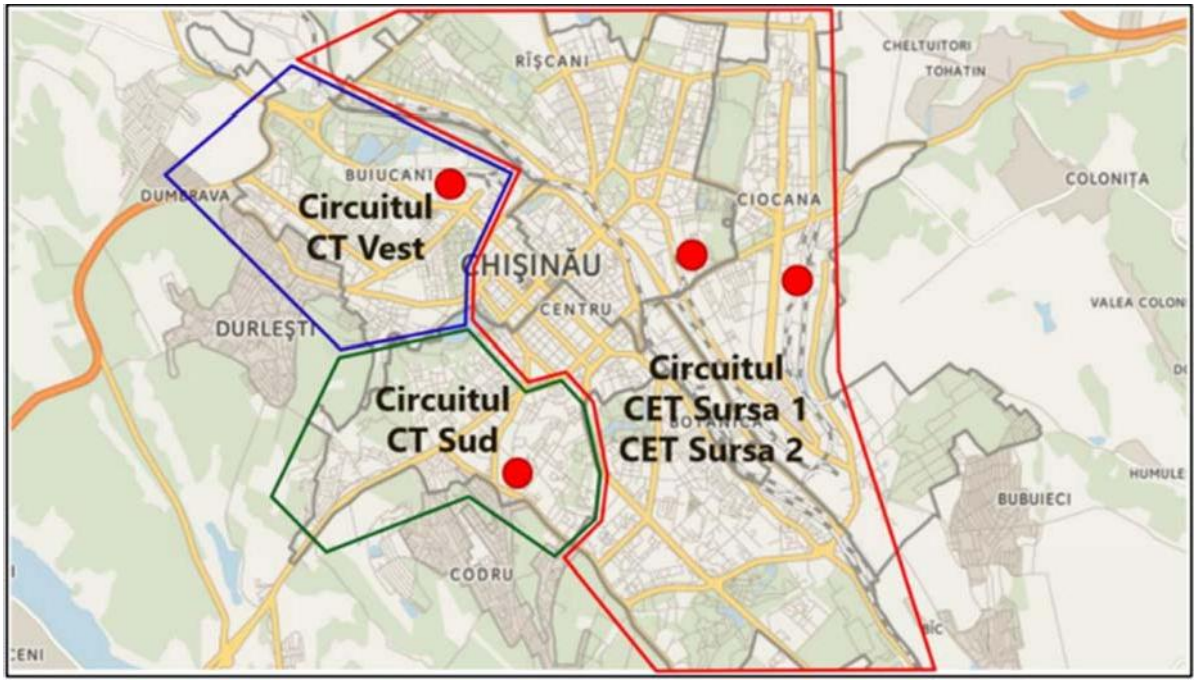


Figure 2-4. DHS system operating areas and corresponding production plants

- **CHP Source 1** is the newer cogeneration plant serving as the primary heat production facility in the northeastern part of the network. It operates predominantly during the heating season, leveraging the newest available technology to meet the high demand for heat and electricity.
- **CHP Source 2** is situated to the west of CHP Source 1 and is an older facility. It is primarily utilized during the summer months to provide heating for domestic hot water (DHW), capitalizing on its suitability for lower load operations.
- **HOB West (CT Vest)** and **HOB South (CT Sud)** are heat-only boiler plants. During the heating season, HOB South DH circuit is isolated from the main DH network using shut-off valves and heat is supplied independently to the respective service area through dedicated boilers.

There is also the decommissioned HOB East plant, which location is planned to be used for other purposes.

2.4.1.1 Operating Regime of CHP and HOB Plants

The operation of these plants is managed to align with seasonal demand variations, technical parameters of the system and to optimize efficiency.

During the **heating season**:

- **CHP Source 1** functions as the main heat source for the primary segment of the DHS, supplying the base load. Each unit at this plant has a minimum boiler output of 200 tons of steam per hour, equivalent to a district heat production capacity of approximately **70–80 Gcal/h**. This capacity matches the increased demand during colder months.

- **HOB South** DH circuit is isolated from the main network using shut-off valves. It operates independently, supplying all the heat required for its specific area. This isolation is necessary due to hydraulic reasons related to the configuration of the system.
- **HOB West** DH circuit remains interconnected with the CHP Source 1 / Source 2 DH circuit. HOB West operates complementarily to the heat supplied from CHP Source 1 / Source 2 to HOB West DH circuit.

During the **off-heating season**:

- The typical summer load for the DHS reduces to around **30–40 Gcal/h**, significantly lower than during the heating season. Operating **CHP Source 1** under these conditions negatively affects economic efficiency because it can only operate in condensing mode. In this mode, excess heat produced cannot be fully utilized and is released into the environment via cooling towers. To mitigate this issue, **CHP Source 2** remains operational during the off-heating season. Its design and operational characteristics make it better suited for the lower demand, efficiently providing domestic hot water services to the entire DHS.
- The shut-off valves separating **HOB West** and **HOB South** from the main network are opened, and these plants are taken offline. This integration allows **CHP Source 2** to supply heat across the entire network, optimizing resource utilization during periods of reduced demand.

At the **beginning of the heating season**:

- In autumn, there is a transitional period where a limited amount of heat can be supplied to the **HOB South** service area from the combined network of **CHP Source 1** and **CHP Source 2**, before HOB South circuit needs to be isolated to operate independently.

2.4.2 CHP Source 1

CHP Source 1 is the newest CHP facility in Chisinau, constructed between 1974 and 1982. The plant primarily utilizes natural gas but can also operate on heavy fuel oil or a combination of both. Situated on the northeastern outskirts of Chisinau, CHP Source 1 is adjacent to the city's industrial zone.



Figure 2-5. CHP Source 1 site

The facility occupies a total area of **31.547 hectares**, with 4.152 hectares currently used by the operational plant buildings (see Figure 2-5 and Figure 2-6). Site elevations range from 84 to 90 meters above sea level, and groundwater levels are between 1 to 4 meters below ground. Foundations of existing structures extend to depths of 8 to 11 meters.

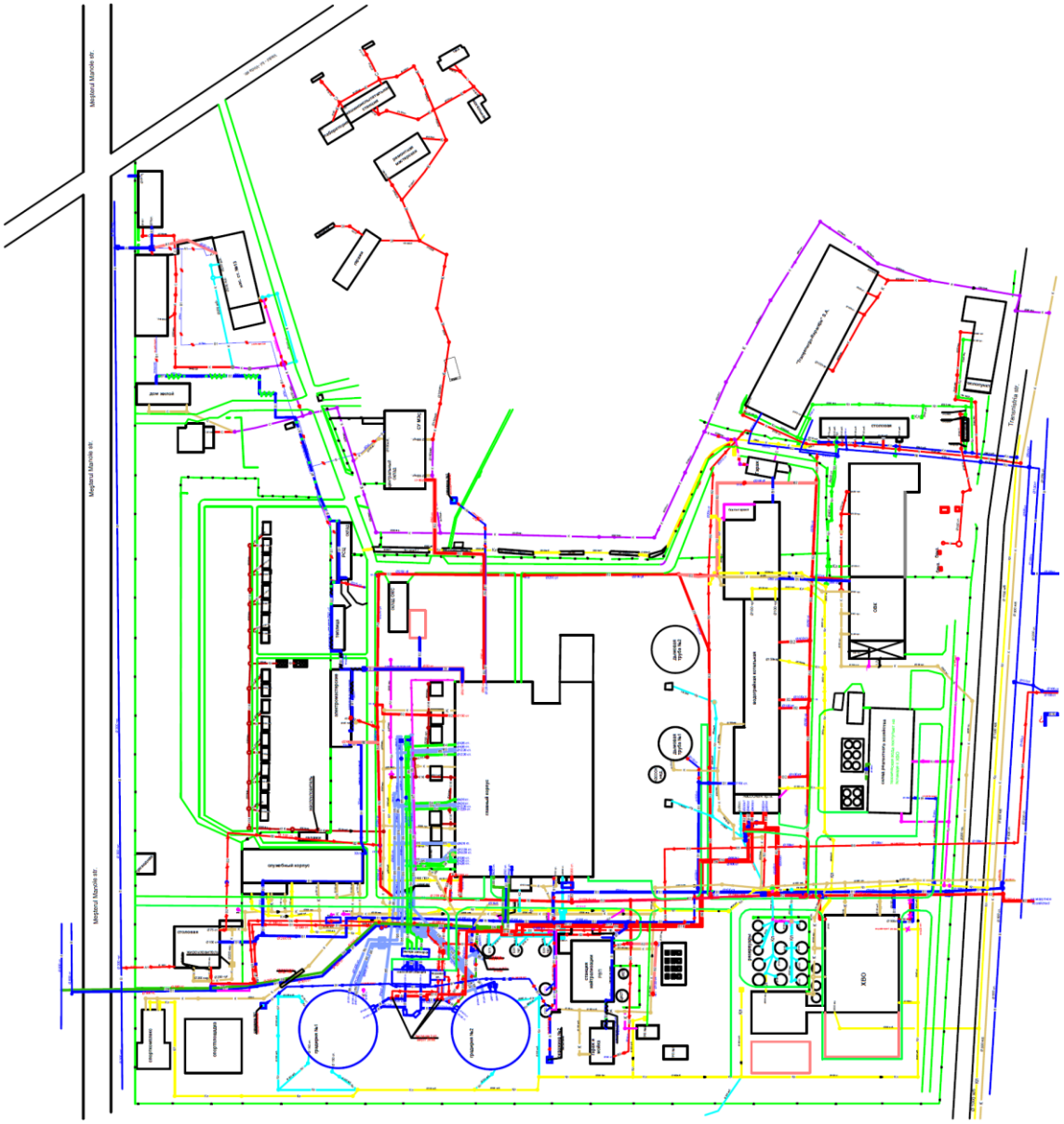


Figure 2-6. CHP Source 1 operational plant layout with water and sewage infrastructure

The generated electricity is supplied to the central electricity supplier – Energocom, which subsequently supplies electricity to the suppliers that deliver it to the final consumers. Thermal energy is provided to urban areas, including Budesti, Riscani, Ciocana and Botanica, as well as other regions through **interconnection pipelines** linking CHP Source 1 and CHP Source 2. Over time, the plant has experienced a significant reduction in industrial steam consumers.

As the largest heat generation facility in the Chisinau District Heating System (DHS) and the largest electricity generator on the right bank of the Nistru (Dniester) River, CHP Source 1 produces 15% of Moldova's total electricity consumption and over half of Chisinau's thermal energy.

The plant comprises three **natural gas-fired CHP** units and five **heat-only boilers (HOBs)**. Natural gas is the primary fuel, with heavy fuel oil as a backup. The CHP units feature three **extraction/condensing steam turbines** (model PT-80/100-130/13) with a two-stage design and two regulating steam extractions. Each turbine is connected to **its own boiler** and directly coupled to an electric generator (model TVF-120-2) rated at 125 MVA. There are **no steam cross-**

connections between turbines, meaning each CHP unit operates independently, i.e. that the boilers of one unit cannot supply steam to the turbines of other units.

Each steam turbine is paired with its own **condenser**, equipped with brass tubes and designed for a circulating water flow rate of 8,000 m³/h. The total condenser cooling load is estimated at 225 MWt (75 MWt per unit). Cooling is provided by two counter-flow, natural draft cooling towers with a design thermal load of 156.6 MWt, serving all three turbines.

Electricity generation utilizes TVF-120 2U3 (ТВФ-120-2У3) hydrogen-cooled generators manufactured by Elektro-Power, St. Petersburg, installed in 1976, 1978, and 1980. These generators have a nominal capacity of 120 MVA (96 MW per unit), a power factor of $\cos\varphi = 0.8$, and an efficiency of 98.4%.

Original Heat and Power Generation Capacities:

- **Nominal electrical capacity per unit:** ~80 MW, one of the turbines having a capacity of 98 MW
- **District heating (DH) capacity per unit:** ~175 Gcal/h
- **Combined DH capacity of all units:** Limited to 375 Gcal/h due to throughput restrictions in the medium-low pressure turbine sections
- **Total DH heat exchanger capacity after high-pressure stages:** 75 Gcal/h

The plant includes six high-pressure **steam heat exchangers** totalling 75 Gcal/h. Each CHP unit also has two low-pressure steam heat exchangers, providing an additional 100 Gcal/h DH capacity per unit. Since the maximum steam throughput capacity of the medium-low pressure cylinders is defined by DH output capacity (corresponding to 270 tons of steam per hour), a portion of the steam is extracted before entering the medium-low pressure turbine section.

The existing units had reached the **end of their original operational lifetimes**, necessitating reconstruction or major overhauls to extend service life. Between 2016 and 2018, Termoelectrica prepared technical documentation for reconstructing one power unit. In 2020, CHP Unit 1 was **retrofitted**, extending its service life by 10 years, increasing nominal electrical capacity from 80 MW to 98 MW, and boosting nominal DH output from the medium-low pressure turbine section from 100 Gcal/h to 160 Gcal/h.

Table 2-4. CHP Source 1 technical data – CHP units

CHP Source 1		Unit 1	Unit 2	Unit 3
Turbine part				
Turbine manufacturer				
Turbine type designation		PT-80/100-130/13	PT-80/100-130/13	PT-80/100-130/13
Turbine type (back pressure/extraction condensing		extraction condensing	extraction condensing	extraction condensing
Turbine commissioning year / reconstruction		1976/2020	1978	1980
Operational info				
Electric capacity (gross)	MW	98	80	80
Live Steam temperature to turbine, design	oC	560	560	560
Live Steam temperature to turbine, actual	oC	555	555	555
Live Steam pressure to turbine, design	bar	140	140	140
Live Steam pressure to turbine, actual	bar	130	130	130
DH capacity	Gcal/h	168	175	175
	Gcal/h	168	100	100

From turbine extraction Via separate heat exchangers / steam from turbine high pressure part	Gcal/h	0	75	75
Fuel consumption	Gcal/h	269	297	297
Steam boilers				
Boiler manufacturer/ Boiler type		TT-96b	TT-96b	TT-96b
Boiler commissioning year / reconstruction		1976/2020	1978	1980
Operational info				
Live Steam temperature, design	oC	560	560	560
Live Steam temperature, actual	oC	555	555	555
Live Steam pressure, design	bar	140	140	140
Live Steam pressure, actual	bar	130	130	130
Live Steam capacity, design	t/h	440	470	470
Live Steam capacity, actual	t/h	275	275	275
Boiler capacity	Gcal/h	200	200	200
Minimum boiler capacity	t/h	93.50 %	92.50 %	92.50 %
Boiler efficiency				
Operation hours				
Annual operation hours (2016)	h/a	5,138	3,106	3,654
Annual operation hours (2017)	h/a	4,841	3,716	2,279
Annual operation hours (2018)	h/a	4,462	2,735	4,597
Total operation hours (Accumulated from commissioning				
up to 31.12.2018)	h			
Gas connection (CHP + HOB)				
Gas delivery pressure	barg		3 - 6	
Maximum available capacity of gas	m3/h		150,000 - 300,000	

Table 2-5. CHP Source 1 technical data – HOB units

CHP Source 1 (Hot Water Boilers)						
		Boiler 1	**Boiler 2**	**Boiler 3**	**Boiler 4**	**Boiler 5**
Boiler type		PTVM-100	PTVM-100	PTVM-100	KVGM-180	KVGM-180
Boiler commissioning year		1974	1975	1982	1990	1991
Operational (yes/no)		No	Yes	Yes	No	No
Operational info						
DH production capacity, design	Gcal/h	100	100	100	180	180
DH production capacity, actual	Gcal/h	0	100	100	0	0
Minimum capacity	Gcal/h	20	20	20	-	-
Boiler efficiency	%	91	91	91	91.7	91.7
Plant efficiency	%	91	91	91	91.7	91.7
Operation hours						
Annual operating hours (2016)	h/a	0	1,470	67	0	0
Annual operating hours (2017)	h/a	0	73	0	0	0
Annual operating hours (2018)	h/a	0	53	0	0	0
Total operation hours (accumulated from commissioning up to 31.12.2018)	h	31,664	23,729	20,366	3,943	1,819

The existing units have exceeded their original operational lifetimes and are maintained to extend their use until they can be replaced with modern, high-efficiency facilities.

Once new facilities to replace the existing capacities are operational, the existing heat and power generation facilities at CHP Source 1 will not be further used.

Regarding **HOBs**, three natural **gas/heavy fuel oil-fired hot water boilers** type PTVM-100 were commissioned between 1974 and 1982, and two KVGM-180 boilers in 1990 and 1991 respectively. Currently, only two PTVM-100 boilers remain in use. These boilers operate during peak heat demand periods—approximately two months in 2016 and several days during the 2017 and 2018 heating seasons. As of late 2018, Boiler 2 had accumulated 31,664 operating hours, and Boiler 3 had 23,729 hours.

2.4.2.1 Operating Modes

The plant can operate in two modes:

- **Mode 1:** One unit at full load; two units at partial load
- **Mode 2:** All units at equal load

In **condensing mode**, electric power capacity is limited by the steam condenser's maximum condensation rate of 220 t/h at optimal cooling water temperature of 20 °C. Due to low process steam demand, maximum power output is largely dependent on DH load. The maximum capacity in condensing mode is **160 MW_e** (2×80 MWe), with the cooling water flow rate restricted to 5,000 m³/h per turbine (it is essential to implement a cooling system for the **ПСГ-1** pipes to ensure proper operation in condensing mode). During the **heating season**, with sufficient DH demand, the plant can operate at **full capacity**. The reported gross energy efficiency is 80% in DH mode, 28% in condensing mode, and 94% for heat generation alone.

2.4.2.2 Available area for future expansion

The **CHP Source 1** overall available land area is 42 hectares, with area of approximately 32 hectares currently used by the operational plant and its infrastructure (see Figure 2-5 and Figure 2-6). Through the comparison of area used by current operational plant and total area, area of approximately **10 hectares** to the northeast of current plant can be identified as the potential area for building majority of **future expansions**. If space between buildings of existing, operational, would be considered for building, position of existing infrastructure and corresponding underground lines need to be taken into account.



Figure 2-7. Identification of available area for future expansion

2.4.2.3 Available infrastructure in the CHP Source 1 site location

2.4.2.3.1 Fuel handling system

CHP Source 1 primarily relies on natural gas as its main fuel, with heavy fuel oil (HFO) serving as a backup. Natural gas is delivered to Chisinau through a high-pressure main pipeline operating at **55 barg**. Upon entering the city's distribution system, the gas pressure is reduced first to **12 barg** and then further down **6 barg** and 3 **barg**. The plant connects to this 3 barg distribution system **500 mm**, while 6 bar distribution is done through pipes with diameter 600 mm. At on-site pressure reducing and metering station, the gas is metered, filtered, and its pressure is decreased to **0.85 barg**. Equipment installed in **2002** records the gas temperature, pressure, and flow rate.

HFO is delivered to the plant by railway, but can also be delivered by trucks. Steam system is used to heat the HFO in the railway tankers, and up to **16 tankers** can be unloaded simultaneously. The HFO handling system includes a transfer tank at the railway, storage tanks equipped with steam

heating coils to maintain the required viscosity, filtering equipment, and an HFO heating and pumping system. The total available storage capacity is about **34,000 m³**, sufficient for approximately one month of operation at a load of 30–40%. The unloading tank – a concrete underground tank of **1,000 m³**, and four storage tanks, each with a capacity of **20,000 m³ (out of which two are available)**, were installed in the 80s. The pumps used are over 30 years old, but the overall condition of the HFO system is reported as satisfactory.

2.4.2.3.2 Flue gas system

Flue gases are emitted through a **180 m** operational stack with a diameter of **7.2 m**. An additional 240 m stack with a 9.6 m diameter remains unfinished, originally intended for an abandoned expansion project, and is currently about 80% complete. The existing stack adequately handles emissions from the three active units and two standby hot water boilers.

2.4.2.3.3 Cooling system

Each steam turbine in the facility is equipped with its own dedicated steam condenser, all of which are reported to be in good operational condition. These condensers are constructed with brass tubes and designed to handle a circulating water flow rate of 8,000 m³/h, ensuring efficient heat transfer from the steam to the cooling water. The designed cooling load demand for each **condenser** is estimated at 75 MWt. For the entire plant, comprising three steam turbines, this amounts to a **total cooling load of 225 MWt**.

The cooling of the condensers is achieved through a circulating water system that transfers heat from the condensers to two cooling towers, which serve all three turbines collectively. These cooling towers are of the natural draft, counter-flow type. In this design, air flows upward naturally due to the buoyancy effect created by the warm air inside the tower being less dense than the cooler ambient air outside. Simultaneously, water flows downward against the rising air, maximizing the contact time and surface area for heat exchange between the water and air.

The overall **cooling system** has a capacity of **156.6 MWt**, which is approximately 70% of the total cooling capacity required for the full 100% operation of all three units in condensing mode. The design temperature range (Δt) of the cooling system is 9 °C.

The total circulating water flow through the cooling system amounts to **260,870** cubic meters per day (**m³/day**) for both cooling towers combined. This high flow rate is necessary to absorb and dissipate the significant amounts of heat extracted from the steam during condensation. The large volume of water ensures that the condensers operate effectively, maintaining the vacuum conditions required for optimal steam turbine performance.

2.4.2.3.4 Water treatment system

The water treatment system at CHP Source 1 comprises several essential processes designed to ensure the quality and reliability of water used throughout the facility. These processes include:

- **Raw Water Pre-Treatment System**: This system features two clarifiers dedicated to lime-soda softening and coagulation. The lime-soda softening process reduces water hardness through addition of calcium hydroxide precipitating calcium and magnesium ions, while coagulation removes suspended particles and colloidal substances. The total capacity of these clarifiers is 70 cubic meters per hour (m³/h), preparing raw water for further treatment stages.
- **District Heating Network Makeup Water System**: To supply the district heating network with high-quality water, this system utilizes a two-stage sodium cation (Na^+) exchange process. The ion exchange removes hardness-causing ions, preventing scale formation in the network. The main unit has a capacity of 250 m³/h, ensuring sufficient supply during

peak demand, while a backup system with a capacity of 150 m³/h provides redundancy and operational reliability.

- **Demineralization System**: Operating at a capacity of 200 m³/h, this system employs a four-bed ion exchange process. The four stages typically include strong acid cation (SAC) exchange H^+ ions with cation portion of total dissolved solids (TDS) and are regenerated by diluted acid solution (H+), degasification process to remove carbon dioxide, strong base anion (SBA) exchange OH^- ions with anion portion of TDS and are regenerated by dilute sodium hydroxide (OH-), and mixed-bed ion exchange polishing removes the last traces of undesirable ions. This comprehensive treatment removes dissolved minerals and ionic impurities, producing demineralized water suitable for use in high-pressure boilers and other critical applications where water purity is essential.

- **Returning Condensate Oil Removal System**: Designed to purify condensate return streams, this system removes oil and other contaminants that can impair boiler efficiency and longevity. The treatment sequence involves a mechanical filter to eliminate particulate matter, an activated carbon filter to adsorb organic compounds and oils, and a sodium cation exchange unit to soften the water. This process with capacity of 40 m³/h ensures that of condensate can be safely recycled back into the system, reducing water consumption and operational costs.

- **Regeneration of Backwash Water**: To enhance sustainability and reduce waste, the plant includes a regeneration system for backwash water used in various filtration processes. This system consists of four regeneration tanks, each with a capacity of 400 m³. The treatment involves mixing lime and chlorine to neutralize contaminants, followed by solid-liquid separation using two filter presses (FPAKM). Pumps are then used to return the treated water to the system or dispose of it appropriately, minimizing environmental impact.

- Neutralisation of the water from filter media regeneration. The water resulting from the regeneration and washing of the filter media is neutralised in two neutralisation tanks with a capacity of 350 m³, using a lime solution. After neutralisation, the treated water is discharged for storage in the wastewater accumulation basin.

- **Wastewater Treatment System** which handles all wastewater generated by the plant's operations. It ensures that effluents meet environmental regulations before discharge, employing processes such as neutralization, sedimentation, biological treatment, and disinfection. The environmental protection laboratory carries out regular monitoring and verification of the quality of the discharged wastewater.

- **Central and Express Laboratories**: Equipped with advanced analytical instruments, these labs perform regular monitoring and testing of water quality. They play a vital role in ensuring that the treatment processes are effective and that the water meets all necessary specifications for use in the plant.

- **Reagents storage and preparation area**: This section stores and prepares the chemical reagents used in various water treatment processes, including acids, alkalis, lime, flocculants, corrosion inhibitors, etc. Proper handling of these chemicals is essential for effective treatment and safety.

Plant consumption of demineralized water is on the level of 383,000 m³, and chemically treated water on the level of 1,892,820 m³.

2.4.2.3.5 High voltage electrical system

CHP Source 1 is connected to the Moldelectrica 330 kV Straseni substation via **25 kilometers of triple 110 kV transmission lines** owned and operated by Premier Energy. These lines serve as the main conduit for transferring the electrical power generated at CHP Source 1 to the broader electrical grid managed by Moldelectrica.

Recent assessments indicate that these existing **110 kV transmission lines** have the capacity to support approximately **100 MW of additional generation** at the CHP Source 1 site. This suggests that the current infrastructure is robust enough to handle modest increase in power output without necessitating significant upgrades or the construction of new transmission lines.

The **high-voltage substation** located on the CHP Source 1 premises is owned by Termoelectrica. Notably, the substation's isophase bus bar has two available sections for the installation of additional circuit breakers.

2.4.2.3.6 Transformers

Each of the three generators in the facility is connected to its own **125 MVA Generator Step-up Transformer** with two windings rated at **110-10 kV**. These transformers are increasing the voltage generated by the generators up to the transmission voltage level.

In addition to the main step-up transformers, each generator is also connected to a **25 MVA Unit Auxiliary Transformer** with three windings rated at **10-6/6 kV**. This configuration provides operational flexibility and enhances the reliability of the power distribution within the plant.

The plant has split main bus system. Specifically, **Generator Step-up Transformers 1T and 2T** are connected to the **110 kV Bus Section A**, while **Generator Step-up Transformer 3T** is connected to the **110 kV Bus Section B**.

The Unit Auxiliary Transformers associated with the generators – designated as **21T, 22T, and 23T** – are responsible for supplying power to the **6 kV Unit Auxiliary sectionalizing buses**. These buses distribute electricity to various auxiliary systems, ensuring that all necessary equipment receives the appropriate voltage for safe and efficient operation. Each of these Unit Auxiliary Transformers is equipped with an **on-load tap changer (OLTC)**. The OLTC allows for adjustments to the transformer's output voltage while it is energized and under load.

In addition to the unit-specific transformers, the plant is equipped with two **Station Auxiliary Transformers**, designated as **20T** and **30T**. Transformer **20T** is rated at **32 MVA** with voltage ratings of **110-6/6 kV**, and Transformer **30T** is rated at **40 MVA** with the same voltage ratings. These station transformers are connected to the **110 kV buses** and the **6 kV Unit Auxiliary buses**. Their primary function is to provide auxiliary power to the plant, independent of the generators.

A summary of the technical data for these transformers is provided in Table 2-6.

Table 2-6. Transformer technical data

Model	Capacity, kVA	Voltage, kV	Year installed	Designation
TRDN-32000 110/6/6	32,000	115	1976	20T
TDTs-125000 110/10	125,000	121	1989	1T
TRDNS25000 10/6/6	25,000	10,5	1976	21T
TDTs-125000 110/10	125,000	121	1986	2T
TRDNS25000 10/6/6	25,000	10,5	1978	22T
TDTs-125000 110/10	125,000	121	1980	3T
TRDNS25000 10/6/6	25,000	10,5	1980	23T
TRNDTsN40000 25000/110/6.6/6.6	40,000/25,000	115	1980	30T

2.4.2.3.7 District heating circulation pumps

The DH water is circulated via circulation pumps that are divided into two pump groups. DH circulation pumps technical data are presented in Table 2-7.

Table 2-7. District heating circulation pumps technical data

Pump Group	Model	Quantity	Capacity m^3/h x dP (bar)	Electric Drive / Unit, KW	Total Capacity, m^3/h
1	CƎ (SE)-5000 x 50	4	5,000 x 5	1,000	20,000
2	CƎ (SE)-1250 x 140	7	1,250 x 14	630	8,750
	CƎ (SE)-5000 x 160	3	5,000 x 16	3,200	15,000
	CƎ (SE)-2500 x 180	3	2,500 x 18	1,500	7,500

2.4.2.3.8 Connection to gas grid

CHP Source 1 is connected to the natural gas grid through a two gas pipelines: one at a pressure of 6 bar, connected to SRG-2 with a maximum capacity of 300,000 m^3/h, the other at a pressure of 3 bar, connected to SRG-1 with a maximum capacity of 150,000 m3/h. These pipelines ensure that the facility has access to sufficient natural gas to meet its operational demands, especially during peak load conditions.

An on-site **pressure regulating and metering station**, also designed for an operating pressure of 6 barg, is integral to the system. This station performs critical functions:

- **Pressure Regulation**: It adjusts the incoming gas pressure to levels suitable for the plant's equipment, ensuring safe and efficient combustion processes.
- **Flow Measurement**: Accurate metering of the gas flow allows for precise monitoring of consumption, essential for operational management and billing purposes.

However, the pipeline is currently operating at a reduced pressure of **3 barg**. Consequently, the maximum corresponding flow rate through the pipeline is effectively halved to **150,000 m^3/h**.

Despite operating at a reduced pressure and flow rate, the current gas supply infrastructure adequately meets the needs of CHP Source 1. At maximum load, the facility consumes approximately **90,000 m^3/h** of natural gas. This peak consumption is well within the adjusted maximum flow capacity of 150,000 m^3/h, leaving a margin for operational flexibility. On average, the plant's natural gas consumption is around **60,000 m^3/h**, which is significantly lower than both the maximum consumption rate and the pipeline's current capacity.

The natural gas supply system for CHP Source 1 is well-designed to meet the facility's current operational requirements. The pipeline and pressure regulating station, even while operating at reduced pressure, exceeds needed capacity for both average and peak consumption levels. For future expansions or increased gas demands, proactive planning and possible infrastructure enhancements could be necessary to ensure a reliable and sufficient gas supply.

2.4.2.3.9 Plant control system

The main **plant control room** at CHP Source 1 serves as the **central hub** for operations, receiving **dispatch** orders for both the **electric power grid** and the **district heating network**. Operated by the plant shift supervisor, the control room manages critical systems including the 110 kV switchgear, 6 kV in-house switches, and the fire protection system.

Control panels for Units 1, 2, and 3 are located within this room, enabling centralized control and monitoring. Most equipment is operated manually, with operators relying on monitoring instruments to oversee plant performance. The control room is equipped with metering systems that measure and record electricity generation, steam production, and heat supply. Additionally, the consumption of natural gas and heavy fuel oil (HFO) is tracked to calculate the plant's performance metrics.

2.4.3 CHP Source 2

Located in **northeastern central Chisinau**, **CHP Source 2** is the closest heat production facility to the city centre. The plant comprises approximately 30 buildings, with a total area exceeding **20,000 m²**, spread across **14 hectares**. Constructed in three phases from 1951 to 1961, it was originally coal-fired plant but converted to natural gas between 1966 and 1969, with heavy fuel oil as backup.

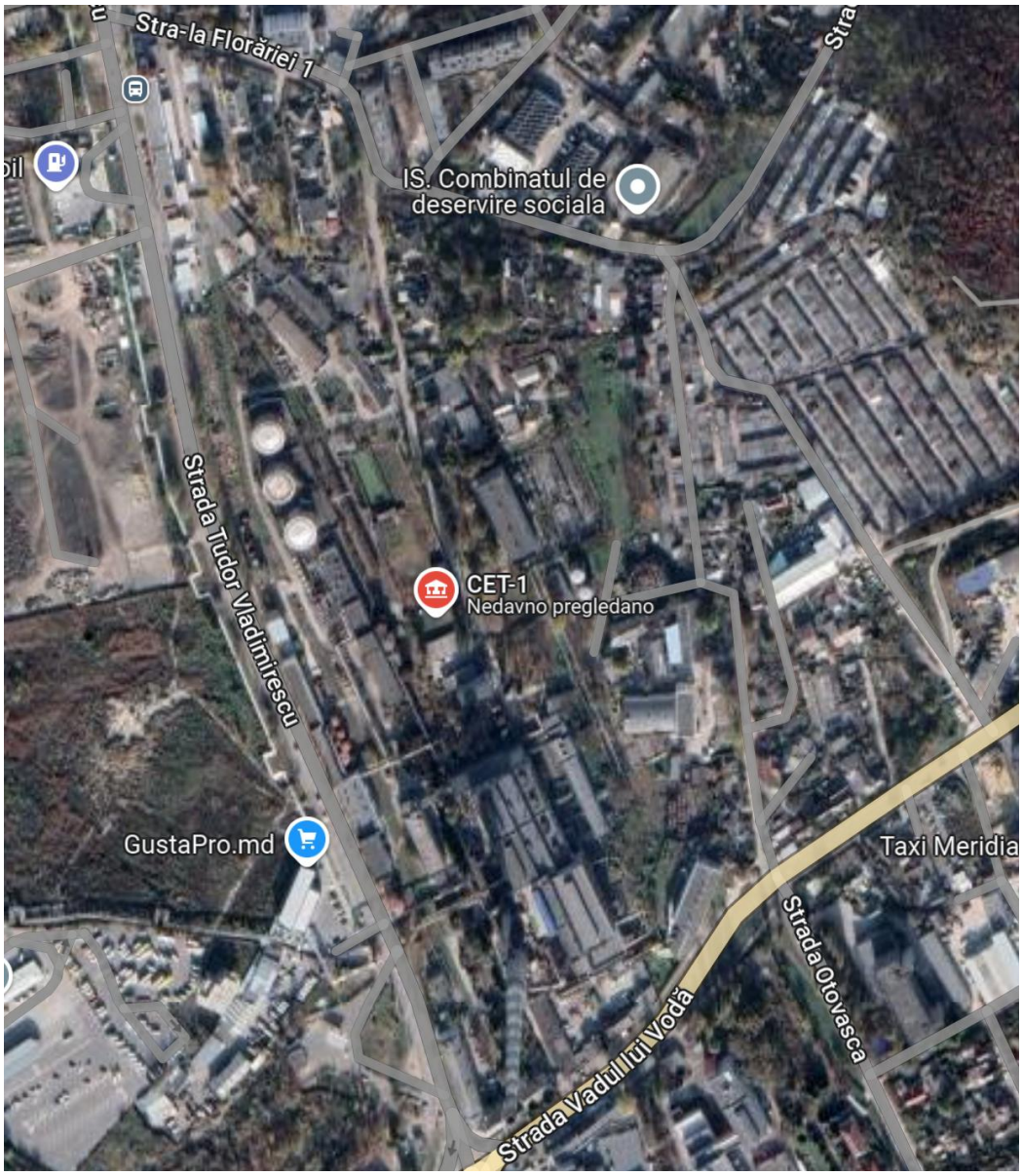


Figure 2-8. CHP Source 2 site

The plant includes **five back-pressure steam turbine generators** commissioned between 1958 and 2001, and eight natural gas-fired steam boilers from 1951 to 1961. Steam headers **interconnect** all boilers and turbines, allowing flexible operation. Currently, only **two turbines** (models R-12-32-3M commissioned in 1994 and PT-12/15-35/10M in 2021) **and four boilers** (model GM-50 from 1951 and 1955) are **operational**, primarily meeting reduced **summer demand**. The operational turbines have an electric output of **12 MWe**. CHP Source 2 **supplies** external customers and its own auxiliary loads via **110 kV lines** and 6 kV lines.

Table 2-8. CHP Source 2 technical data – Turbines and steam boilers

Turbine part		Turbine 1	Turbine 2	Turbine 3	Turbine 4	Turbine 5
Turbine type designation		P-12-35-3M	ПТ-12/15-35/10М	ПР-10-35/10-1,2	P-27-90/1,2	P-5-90/37
Turbine type		Back-pressure	Back-pressure	Back-pressure	Back-pressure	Back-pressure
Turbine commissioning year		1994	2001	1958	1960	1961
Operational (yes/no)		Yes (in summer)	Yes (in summer)	No	No	No
Operational info						
Electric capacity (gross)	MW	12	12	10	27	5
Design	MW	12	12	10	27	5
Actual	MW	12	12	n.a.	n.a.	n.a.
Live Steam temperature to turbine, design	°C	440	440	440	520	520
Live Steam temperature to turbine, actual	°C	435	435	n.a.	n.a.	n.a.
Live Steam pressure to turbine, design	bar	40	40	40	90	90
Live Steam pressure to turbine, actual	bar	35	35	n.a.	n.a.	n.a.
DH capacity, design	Gcal/h	57	60	67	70	0
DH capacity, actual	Gcal/h	57	45	n.a.	n.a.	n.a.
Turbine operation hours						
Annual operating hours (2016)	h/a	657	2,124	0	1,311	1,954
Annual operating hours (2017)	h/a	4,126	0	0	0	0
Annual operating hours (2018)	h/a	4,564	0	0	0	0
Total operation hours (accumulated from commissioning up to 31.12.2018)	h	36,940	68,697	318,379	228,204	135,102

Boilers		Boiler 1	Boiler 2	Boiler 3	Boiler 4	Boiler 5	Boiler 6	Boiler 7	Boiler 8
Boiler type		ГМ-50	ГМ-50	ГМ-50	ГМ-50	ГМ-50	ГМ-50	БКЗ-120-100Г М	БКЗ-120-100Г М
Boiler commissioning year		1951	1951	1954	1955	1958	1959	1961	1961
Operational status		Operated in summer	Operated in summer	Operated in summer	Operated in summer	Not in operation	Not in operation	Not in operation	Not in operation
Operational info									
Live Steam temperature, design	°C	440	440	440	440	440	440	520	520
Live Steam temperature, actual	°C	440	440	440	440	n.a.	n.a.	n.a.	n.a.
Live Steam pressure, design	bar	39	39	39	39	39	39	92	92
Live Steam pressure, actual	bar	39	39	39	39	n.a.	n.a.	n.a.	n.a.
Live Steam capacity, design	t/h	50	50	50	50	50	50	120	120
Live Steam capacity, actual	t/h	35	35	47	47	n.a.	n.a.	n.a.	n.a.
Boiler capacity, design	Gcal/h	33	33	33	33	33	33	74	74
Boiler capacity, actual	Gcal/h	23	23	31	31	n.a.	n.a.	n.a.	n.a.
Minimum boiler capacity	t/h	25	25	25	25	n.a.	n.a.	n.a.	n.a.
Boiler efficiency		94 %	94 %	94 %	94 %	n.a.	n.a.	n.a.	n.a.
Boiler operation hours									
Annual operating hours (2016)	h/a	0	55	560	828	0	0	1,983	1,282
Annual operating hours (2017)	h/a	0	1,936	3,189	2,944	0	0	0	0
Annual operating hours (2018)	h/a	0	4,450	4,520	206	0	0	0	0
Total operation hours (accumulated from commissioning up to 31.12.2018)	h	254,866	251,007	232,871	245,573	208,592	227,685	196,783	
Gas connection									
Gas delivery pressure	barg	2.94							
Maximum available capacity of gas	m^3/h	41,666							

The plant is equipped with **steam headers** that **interconnect** the inlets and outlets of the boilers and turbines, enabling **flexible operation** with various combinations of boilers and turbines. The DH return water is initially heated by heat exchangers using extraction and back-pressure steam.

Due to aging equipment, the facility operates with low electricity generation efficiency and is **slated for closure** in the near future.

2.4.3.1 Operating Modes

CHP Source 2 cannot operate without DH load or steam supply to local industries. It follows DH load by varying supply temperature while maintaining nearly constant water flow during the heating season. Base load steam for DH heaters is provided from turbine exhaust. The DH water in the return line is heated first by heat exchangers with extraction and back-pressure steam. Available infrastructure in the CHP Source 2 site location

2.4.3.1.1 Fuel handling system

CHP Source 2, as well as CHP Source 1 primarily relies on natural gas as its main fuel, with heavy fuel oil (HFO) serving as a backup. Natural gas is delivered to Chisinau through a high-pressure main pipeline operating at **55 barg**. Upon entering the city's distribution system, the gas pressure is reduced first to **12 barg** and then further down to **3 barg**. The plant connects to this 3 barg distribution system **500 mm**. At on-site pressure reducing and metering station, the gas is metered, filtered, and its pressure is decreased to **0.5 barg**. Equipment installed in **1994** records the gas temperature, pressure, and flow rate.

HFO is delivered to the plant by railway, but its condition is unsatisfactory. **Steam lances** are used to heat the HFO in the railway tankers, and up to **16 tankers** can be unloaded simultaneously. The HFO handling system includes a transfer tank at the railway, storage tanks equipped with steam heating coils to maintain the required viscosity, filtering equipment, and an HFO heating and pumping system. The total storage capacity is about **16,000 m³**, sufficient for approximately one month of operation at a load of 30–40%. The unloading tank – a concrete underground tank of **3,500 m³** – and three storage tanks, each with a capacity of **5,000 m³**, were installed in **1997**. The pumps used are over **30 years old**, but the overall condition of the HFO system is reported as satisfactory.

2.4.3.1.2 Water treatment system

CHP Source 2 maintains a contractual agreement with "APA-Canal" JSC for the supply of raw water essential to its operations. The water treatment plant at CHP Source 2 comprises several critical facilities designed to ensure that the water meets the stringent quality requirements necessary for efficient and safe plant operation. The key components of the water treatment system include:

- **Demineralization Unit**: This facility is responsible for removing dissolved minerals and ions from the water. Demineralized water is crucial for boiler feedwater to prevent scaling, corrosion, and other issues that can negatively impact the efficiency and longevity of steam generation equipment.
- **Pre-Treatment Facility**: Commissioned in 1987, the pre-treatment facility prepares incoming raw water by removing suspended solids, turbidity, and other impurities. Processes such as coagulation, flocculation, sedimentation, and filtration are typically employed to improve water quality before it enters more sensitive treatment stages.
- **Reagent Storage and Preparation Area**: This section stores and prepares the chemical reagents used in various water treatment processes, including coagulants, flocculants, pH adjusters, and disinfectants. Proper management of these chemicals is essential for effective treatment and safety.

- **Waste Treatment Facility**: Commissioned in 1979, this facility handles the treatment of waste streams generated from the water treatment processes. It ensures that sludge, backwash water, and other by-products are treated appropriately before disposal, complying with environmental regulations.
- **Storage Tanks**: The plant includes various tanks for storing raw water, treated water, and chemical reagents. These tanks provide buffer capacity to manage fluctuations in water supply and demand, ensuring a continuous and reliable operation.
- **Central and Express Laboratories**: Equipped with advanced analytical instruments, these labs perform regular monitoring and testing of water quality. They play a vital role in ensuring that the treatment processes are effective and that the water meets all necessary specifications for use in the plant.

The major components of the water treatment plant were initially commissioned in May 1973. Despite their age, all facilities are reported to be in **satisfactory condition**, indicating consistent maintenance and operational diligence. Installed capacities for water treatment, by design are, **500 m3/h for pretreatment**, **250 m3/h for district heating water** makeup and **150 m3/h for demineralized water** makeup.

2.4.3.1.3 High voltage electrical system

Electrical power generation at CHP Source 2 involves four air cooled generators—G1, G4, G5, and G6—each connected to their respective steam turbines (1, 4, 5, and 6).

Generators G1, G4, and G6 are connected to five sections of **6.3 kV assembly buses**. These buses can be quickly switched between operational and reserve status without interrupting power supply, enhancing reliability and maintenance flexibility. **Generator G5** could supply power directly to **110 kV external customers** and to the plant's **auxiliary loads**. The five assembly bus sections are capable of supplying power to both **6 kV and 110 kV external customers**, as well as to **CHP Source 2's auxiliary systems**.

This configuration allows for flexible and reliable electricity distribution, efficiently meeting both internal operational needs and external customer demands.

2.4.3.1.4 District heating circulation pumps

The DH water is circulated via seven **circulation pumps**, model СЭ (SE) -1250 x 140. Each pump has capacity of **1,250 m3/h** and power of **630kW**.

2.4.4 HOB West

HOB West is in the Buiucani district, **northwest Chisinau**. The facility spans over **2.772 hectares** and boasts an installed heat capacity of **400 Gcal/h**. The plant has **four** PTVM-100 **hot water boilers** (commissioned 1968–1981) and two DKVR-6.5/13 steam boilers (commissioned in 1983). Currently, three hot water boilers and both steam boilers are operational, typically running up to three months per year. During the heating season, HOB West supplies heat to its designated area within the Chisinau DH system.

2.4.5 HOB South

Located in **Chisinau's Central district**, HOB South occupies **2.4 hectares**. The plant has a heat capacity of **310 Gcal/h** and steam production capacity of 30 t/h. The plant **comprises five hot water boilers** and three steam boilers. Currently operational are three hot water boilers (boiler type TGVM-30 (commissioned in 1969), PTVM-50 (commissioned in 1974) and KGVM-100 (commissioned in 1985)), as well as one steam boiler (type DE-6,5/14 (commissioned in 2004)). Hot water boilers TGVM-30, PTVM-50 and KGVM-100 underwent an **overhaul** in 2012, 2018 and 2002 respectively.

2.5 Planned Generating Capacity Projects

As part of the **DHEIP-2 Project**, there are plans to enhance the district heating system's capacity by installing new **high-efficiency cogeneration plants** powered by **gas engines**. These new facilities are proposed at two key locations: CHP Source 3, which will be situated on the territory of the existing CHP Source 2, and at HOB West.

The combined heat generation capacity of these new cogeneration plants is designed to be at least **43 Gcal/h**. This capacity has been specifically selected to **meet the summer district heating load** requirements of the system, ensuring reliable and efficient operation during periods of lower heat demand. In addition to heat production, these plants are expected to contribute approximately **55 MWe** of electrical generation capacity to the grid, enhancing the overall energy supply and supporting the electricity needs of the region.

The integration of these high-efficiency gas engine-based cogeneration units is anticipated to improve the operational flexibility of the district heating system, reduce fuel consumption, and lower greenhouse gas emissions by utilizing modern, efficient technology.

2.6 Location of new CHP DH capacities analysed as a part of this study

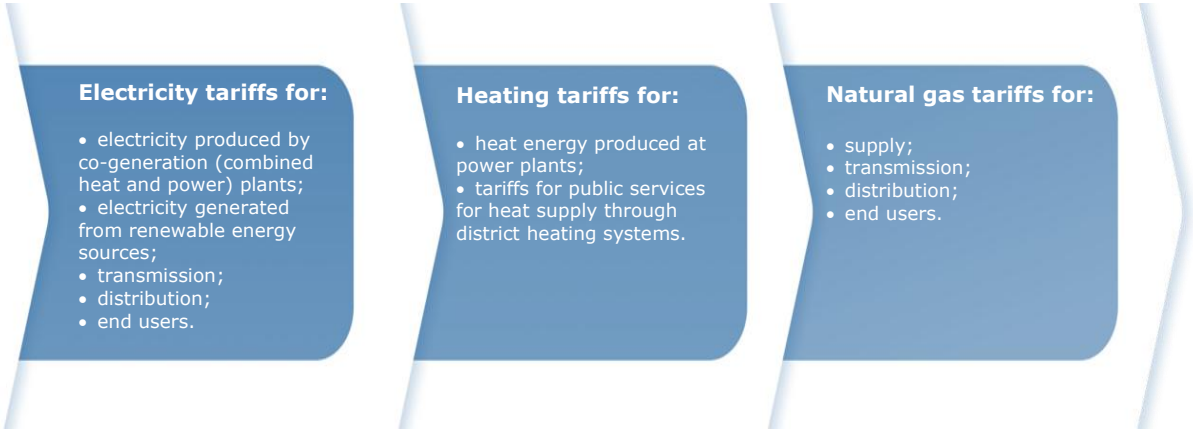
As per project task micro-location for the new high-efficiency CHP DH plant must be provided exclusively within the existing boundaries of the existing CHP Source 1 plant. As per analysis of the existing location of CHP Source 1 plant, possibility of partial expansion to the north east of the existing CHP plant will be analysed. Also, in accordance with the project task, it is necessary to analyse the influence of building accompanying units such as WtE plants and DH plants based on RES off site. Location of these production units is provided by the client and described in corresponding chapters.

3. Legal Framework

3.1 Regulatory Framework Overview

The energy market in Moldova is regulated by a comprehensive framework aimed at establishing a transparent and justified pricing mechanism. In a market economy, the prices for heat, gas, and electricity are influenced by multiple factors, such as production costs, residential tariffs, seasonal demand fluctuations, and the need for infrastructure modernisation. In Moldova, regulated methodologies are applied to the calculation of energy tariffs to protect the interests of both end consumers and resource suppliers. These methodologies allow for the consideration of current operational expenses, investment costs, and external factors impacting price formation. The National Agency for Energy Regulation (ANRE) sets tariffs based on supplier proposals and up-to-date market data on energy resources, thereby fostering sustainable and fair pricing conditions. It is notable that energy pricing in Moldova has undergone several adjustments recently in response to fluctuations within the energy market.

Energy pricing policy. ANRE regulates and approves electricity, gas and heat tariffs in Moldova. Due to sector unbundling, ANRE regulates tariffs for the energy sector, including the following



Tariffs are calculated based on the technical specifications of each company and the number of customers served. Each year, companies submit their tariff calculations for the following year to ANRE, adhering to methodologies approved by the agency. These calculations include planned operational expenses and capital investments, as well as costs for modernisation, refurbishment, and loss reduction. ANRE then reviews the proposed tariffs, either approving them or providing recommendations for adjustments.

Tariffs and methodologies are transparent and are published in the Official Monitor. To ensure transparency in the approval process, ANRE holds public hearings before finalising the tariffs.

3.1.1 Heat Market Regulations

The EU Directive 2012/27/EU on energy efficiency in the district heating sector was transposed partially in Moldova through primary legislation. The Moldovan Parliament approved the **Law on Heating and Promotion of Cogeneration** (Law no.92 of 29.05.2014)[3] in May 2014. The law is designed to regulate the specific activities of the centralised systems of thermal energy supply, improve the energy efficiency of the entire economy and reduce the negative impact of the thermal energy sector on the environment, including by using cogeneration technologies.

[3] Law of the Republic of Moldova "On Thermal Energy and Promotion of Cogeneration" No. 92 of 29.05.2014

Over the past two years, Moldova has seen positive developments in heat pricing driven by optimised fuel costs and infrastructure modernisation. In 2023, the Government of Moldova approved a **new methodology for allocating heating costs** among residents of apartment buildings[4].

Moldova provides subsidies to household consumers in the district heating sector through different channels. The VAT rate for district heating used by households is 0%, while the standard VAT rate in Moldova is 20% which is applied to DH supplied to the non-residential/public sector. In addition, there are compensation schemes to protect the most vulnerable consumers, at both the national and local levels. At the national level, such schemes pay fixed amounts (e.g. per family or person), regardless of the amount of energy used. However, some local schemes (e.g. the compensation paid in Chisinau to low-income families) provide payment as a percentage of the energy bills.

This revised approach takes into account specific characteristics of each building and flat, such as the area, number of rooms, location within the building, and type of insulation. This adjustment aims to ensure fair cost distribution among residents. Key changes include adjustments to the formula, application method, and consumer information provided.

Under the **previous methodology**, all owners of flats disconnected from the centralised heating system paid a fixed fee of 5%, later increased to 10%, of the heating cost calculated per square metre of the flat, regardless of whether they lived in the centre of the building, on a corner, or in the attic.

The **new methodology** includes calculation based on a number of factors to ensure allocation of costs between apartments connected and which had disconnected from DH services (considering that the disconnected apartments also consume a part of the heat from the common heating system of the building), and assigns a more prominent role to building managing entities in the cost allocation process.

As a result of infrastructure reforms and investments to modernise the district heating systems and reconnect/connect new consumers, the performance is increasing.

Further reforms have focused on modernising the district heating system. Connecting approximately 30 public buildings to the district heating network has increased thermal and electrical loads for the relevant companies, improving the financial stability of energy providers. Modernising the heat and power plants has also led to significant energy savings, notably reducing natural gas consumption by 4.7 million m^3 annually.

Table 3-1. Heat tariff

Supplier	Location	Previous tariff (lei/Gcal)	New tariff (lei/Gcal)	Tariff increase (lei)	Reduction increase (%)
Termoelectrica	Chisinau	1,824	2,510	686	+38.0
CHPP-North (CET-Nord)	Balti	1,819	2,126	307	+17.0
Apă-Canal Chișinău	Chisinau	2,241	2,682	441	+20.0
Servicii comunale Glodeni	Glodeni	2,186	2,205	19	+1.0
Rețelele și Centralele Termice Comrat	Comrat	2,882	3,222	340	+12.0
Termotrans Taracalia	Taraclia	2,721	3,102	381	+13.0

[4] Moldova's Government approves new heating costs allocation methodology

Supplier	Location	Previous tariff (lei/Gcal)	New tariff (lei/Gcal)	Tariff increase (lei)	Reduction increase (%)
Antermo	Anenii Noi	2,017	2,293	276	+14.0
Comgaz-Plus	Ungheni	3,578	3,603	25	+1.0

3.1.2 Electricity Market Regulations

ANRE is responsible for developing and approving tariff calculation methodologies, as well as setting tariffs for various services in the electricity sector. ANRE makes such decisions after reviewing proposals from licensees.

ANRE has introduced a unified **"Electricity Supply Tariff for End Consumers"**, which is calculated annually. This tariff covers actual costs associated with:

- energy procurement;
- transmission, distribution, and supply services.

Additionally, ANRE has established a separate tariff for electricity transmission and dispatch services.

It is notable that ANRE has the authority to lower future tariffs in cases of non-compliance with established service quality standards.

The methodology for calculating the electricity transmission tariff is set out in ANRE Decision No. 626 of 27 October 2023, "On Approval of the Methodology for Calculation, Approval, and Application of Tariffs for Electricity Transmission Services"[5]. The transmission tariff was established by ANRE Decision No. 9 of 03 January 2025, "On Approval of the Electricity Transmission Service Tariff"[6], and came into effect on 10 January 2025.

Table 3-2. Electricity tariff

Supplier	Service type	Differentiation	Tariff (excluding VAT)
Moldelectrica	Electricity Transmission	—	248 MDL/MWh
Energocom	Electricity Supply	—	2.8 MDL/kWh
Premier Energy Distribution S.A.	Electricity Distribution	High voltage networks (35; 110 kV)	3.0 bani/kWh
		Medium voltage networks (6; 10 kV)	24.1 bani/kWh
		Low voltage networks (0.4 kV)	84.0 bani/kWh
RED-Nord JSC	Electricity Distribution	Medium voltage networks (6; 10 kV)	29.4 bani/kWh
		Low voltage networks (0.4 kV)	133.6 bani/kWh
Furnizarea Energiei Electrice Nord	Electricity Supply	Transmission entry points	310 bani/kWh
		Transmission exit points	334 bani/kWh
		Medium voltage network connection (6; 10 kV)	364 bani/kWh
		Low voltage network connection (0.4 kV)	468 bani/kWh
ÎCS "Premier Energy" SRL (Universal Service)	Electricity Supply	Transmission entry points	302 bani/kWh
		Transmission exit points	326 bani/kWh
		High voltage network connection (35; 110 kV)	329 bani/kWh

[5] Decision No. 626 of 27 October 2023, "On Approval of the Methodology for Calculation, Approval, and Application of Tariffs for Electricity Transmission Services"
[6] Decision No. 9 of 03 January 2025, "On Approval of the Electricity Transmission Service Tariff"

Supplier	Service type	Differentiation	Tariff (excluding VAT)
		Medium voltage network connection (6; 10 kV)	351 bani/kWh
		Low voltage network connection (0.4 kV)	410 bani/kWh
ÎCS "Premier Energy" SRL (Last Resort Service)	Electricity Supply	Transmission entry points	362 bani/kWh
		Transmission exit points	391 bani/kWh
		High voltage network connection (35; 110 kV)	395 bani/kWh
		Medium voltage network connection (6; 10 kV)	421 bani/kWh
		Low voltage network connection (0.4 kV)	492 bani/kWh

3.1.3 Gas Market Regulations

ANRE is responsible for approving natural gas supply tariffs and has adjusted tariffs in response to the volatility of imported gas prices. These adjustments form part of ANRE's broader efforts to reduce cross-subsidisation within the tariff structure.

As a member of the **Energy Community**, Moldova develops its primary and secondary legislation in line with the Energy Community framework to implement the **EU's Third Energy Package**, with the long-term objective of fully adopting EU energy sector legislation. In line with this policy, Moldova adopted the Gas Law No. 108 of 27 May 2016[7], transposing EU Directive 2009/73/EC on the internal natural gas market and Regulation (EC) 715/2009 on conditions for access to natural gas transmission networks. This law enabled the introduction of the Third European Energy Package provisions, ensuring open access to Moldova's gas transmission and distribution systems for all market participants.

As a result of this law, since at least 2020, Moldovagaz no longer holds a monopoly over Moldova's natural gas supply market, particularly in the **"free pricing"** segment. While Moldovagaz continues to supply gas to consumers at regulated tariffs, it is not the sole player in the open market. ANRE's registry now lists **25 licensed natural gas suppliers**, and several of these companies are actively importing gas into Moldova and supplying it to their clients.

In December 2020, the Gas Law was amended to facilitate bi-directional gas flows to and from Ukraine via backhaul procedures, which began in January 2021. Regulation (EU) No. 312/2014 was transposed into the Network Code to establish balancing responsibilities within the market. Moldovatransgaz was appointed as the Balancing Entity.

To implement the requirements of EU directives, Moldova adopted a substantial package of secondary legislation, which includes, among other measures, the **Methodology for the Calculation, Approval, and Application of Tariffs for Natural Gas Transmission Services**[8]. In November 2020, ANRE approved a new tariff methodology for distribution system operators, introducing **differentiated regulated distribution tariffs based on pressure levels and specific distribution system operators**.

In 2025, ANRE approved new regulated tariffs and prices for natural gas, ensuring that they fully cover the minimum and necessary expenses of gas companies associated with their regulated market activities[9]. Accordingly, network service tariffs are determined at the entry and exit points of the transmission system and at the high, medium, and low-pressure levels of the distribution systems.

The following table provides regulated prices for natural gas supply by Moldovagaz JSC:

[7] Gas Law No. 108 of 27 May 2016
[8] Moldova 2022. Energy Policy Review
[9] Resolution No. 686 of 29.11.2024 On approval of regulated prices for natural gas supplied by Moldovagaz JSC

Table 3-3. Gas tariff

Description	Differentiation	Price excluding VAT (MDL/1,000 m³)
Regulated prices for natural gas supply for end consumers	Transmission network entry points	11,011
	Transmission network exit points	11,101
	High-pressure distribution network exit points	11,220
	Medium-pressure distribution network exit points	12,267
	Low-pressure distribution network exit points	15,502
Regulated prices for emergency natural gas supply	Transmission network exit points	13,766
	High-pressure distribution network exit points	13,889
	Medium-pressure distribution network exit points	14,882
	Low-pressure distribution network exit points	18,166

These regulatory adjustments demonstrate Moldova's commitment to a balanced and equitable tariff system that reflects market dynamics while supporting infrastructure development and maintaining fair consumer prices.

3.1.4 Regulatory Oversight

Several regulatory bodies play a critical role in ensuring the sustainable and efficient functioning of the energy sector by overseeing energy production, network integration, and the regulation of market mechanisms. Their responsibilities include:

- supporting stability and security of energy supply,
- fostering competition, and
- safeguarding the rights of consumers and investors.

The regulators are tasked with promoting market transparency and ensuring compliance with international standards, which is especially important given the global challenges and the need for a transition to renewable energy sources facing the republic.

Table 3-4. Regulatory bodies in Moldova's energy sector

Regulator	Type	Main functions	RES-related functions
Ministry of Energy (ME)	Central state authority in the energy sector	▪ Formulates and implements national energy policies; ▪ Oversees electricity, gas, oil, and district heating sectors; ▪ Develops and implements national energy strategies; ▪ Coordinates energy security measures and modernizes infrastructure; ▪ Oversees compliance with international commitments; ▪ Collaborates with other government bodies and stakeholders.	▪ Develops policies and incentives for renewable energy development; ▪ Implements support measures, including setting strategic priorities in the sector; ▪ Promotes integration of RES projects into the national energy mix; ▪ Encourages private sector investment in clean energy; ▪ Coordinates with environmental authorities on RES project assessments.
National Agency for Energy Regulation (ANRE)	Independent regulator	▪ Licences market participants; ▪ Regulates tariffs, oversees legislative compliance, and develops market mechanisms;	▪ Issues licences for the production of electricity and heat from renewables, biogas, and biofuels;

		▪ Monitors investment plans and promotes competition.	▪ Sets fixed tariffs and price caps for RES-generated electricity; ▪ Develops and enforces regulations; ▪ Ensures compliance with technical and regulatory standards for RES installations, such as solar and geothermal systems, biomass boilers, and heat pumps.
Competition Council	Independent body	▪ Promotes competition in the electricity sector; ▪ prevents anti-competitive practices, and enforces the Competition Law.	
National Bureau of Statistics (NBS)	Government body	▪ Collects and processes statistical data in the energy sector to support analysis and decision-making	
Moldova Investment Agency	Government body	▪ Attracts and supports domestic and foreign investments in energy projects and infrastructure development	
Ministry of Finance	Government body	▪ Oversees financing and public finances; arranges state loans and guarantees for energy projects	
Ministry of Environment (ME)	Government body	▪ Develops and implements environmental policies, monitors compliance with international environmental agreements, and collaborates with MIDR on climate planning	

The regulatory framework of the Republic of Moldova's energy sector covers a wide array of laws and regulations aimed at establishing modern market conditions, supporting energy efficiency, and integrating renewable energy sources. These laws and decrees govern the activities of all market participants, ensuring the achievement of strategic state objectives and adherence to international standards.

- **Regulation on Key Conditions for the Import/Export and Transit of Electricity, No. 583/2005**: governs conditions for international electricity trade and transit procedures.
- **Regulation on the National Energy Efficiency Programme for 2011-2020, No. 833/2011**: sets goals and measures to improve national energy efficiency over the specified decade.
- **Electricity Transmission and Distribution Service Quality Regulation (Decree No. 537/2020)**: defines quality standards and service conditions for electricity transmission and distribution.
- **Electricity Market Rules (Decree No. 283/2020)**: regulates operational rules and mechanisms in the competitive electricity market.
- **Electricity Network Code (Decree No. 423/2019)**: sets technical standards and requirements for electricity transmission networks.
- **Methodology for Calculating Regulated Tariffs (ANRE Decree No. 626/2023)**: describes the methodology for calculating tariffs for electricity transmission and distribution services.

The table below provides an overview of each law's key provisions, including specific points related to the support and regulation of renewable energy sources.

Table 3-5. Key laws governing the energy sector

Law	Description	RES provisions
Electricity Law No. 107 of 27.05.2016	▪ Provides for the liberalisation of the electricity market; ▪ Introduces principles and rules from the EU's Third Energy Package, including unbundling requirements and consumer rights to choose suppliers.	▪ Includes mandatory rules for the energy sector that may facilitate RES integration; ▪ Ensures non-discriminatory market access for suppliers, aiding RES deployment.

Natural Gas Law No. 108 of 27.05.2016	▪ Establishes rules for gas market liberalisation, including unbundling requirements, with exceptions for Moldovagaz and its Gazprom-owned subsidiaries.	▪ Creates transparent competitive conditions, applicable to companies working with renewable biogas or biofuel.
Energy Law No. 174 of 21.09.2017	▪ Sets out rules for all energy sector operators and end-users, reinforcing ANRE's independence, authority, and transparency.	▪ Establishes regulatory mechanisms within ANRE, covering tariff regulation for RES producers and investment attraction for supporting RES projects.
Energy Efficiency Law No. 139 of 19.07.2018	▪ Consolidates national institutions for energy efficiency policy implementation; ▪ Develops financing mechanisms, and encourages private sector engagement.	▪ Implements mandatory energy-saving schemes; ▪ Promotes energy efficiency contracts (ESCO); ▪ Mandates energy audits for large enterprises, sustainable procurement in the public sector, and contracts for financing energy efficiency improvement measures, including RES use.
Renewable Energy Promotion Law No. 10 of 26.02.2016	▪ Introduces new support mechanisms for RES investments, including feed-in tariffs, net metering, and auctions.	▪ Obligates the central supplier to purchase RES energy; ▪ Ensures non-discriminatory network access, and prioritises RES distribution; ▪ Supports small-scale and local RES projects; ▪ Promotes liquid biofuels to achieve a 10% RES target in the transport sector; ▪ Promotes local energy autonomy and distributed energy production.

In 2024, ANRE intensified its efforts to develop mechanisms for implementing the provisions of the Electricity and Natural Gas Laws, which transpose European Union directives and establish conditions for the liberalisation of energy markets in the Republic of Moldova, in line with the commitments under the EU's Third Energy Package.

ANRE has approved and transposed all regulatory acts concerning the electricity and renewable energy sectors as stipulated in the Third Energy Package. Other significant regulations, developed and approved following consultations and technical assistance from the Energy Community Secretariat, include:

- Electricity Market Rules
- Regulation on the Quality of Electricity Transmission and Distribution Services
- Regulation on the Procedure for Switching Electricity Suppliers, as well as fixed tariffs and price caps for renewable energy.

The aim of these regulations is to promote the liberalisation of the national energy market and facilitate its integration into regional energy markets.

ANRE has also approved a series of key regulatory acts for the natural gas sector, including:

- Amendments to the Gas Distribution Network Code
- Regulation on the Procedure for Switching Natural Gas Suppliers and the methodology for calculating, approving, and applying regulated tariffs for natural gas distribution services.

The amendments to the Gas Distribution Network Code establish a harmonised regulatory framework, applying EU-aligned rules for new market participants.

The Regulation on the Procedure for Switching Gas Suppliers is designed to prevent potential abuses by system operators or suppliers against end-users who choose to switch their gas providers.

In **overseeing CHP and renewable energy projects** ANRE plays a vital role. Its functions encompass the following aspects:

- monitoring and licensing of energy producers and establishing regulations to ensure cogeneration facilities comply with quality and safety standards.
- coordinating the process of connecting new CHP facilities and renewables to the grid, developing standards to mitigate instability risks and manage variable generation.
- implementing tariff and subsidy regulation, and support mechanisms for producers who utilise environmentally friendly sources.
- inspecting and auditing adherence to safety and reliability standards. For CHP and renewable sources, special attention is given to environmental protection and energy efficiency.
- promoting RES across all economic sectors; implementing qualification and registration systems for RES installers; providing public consultation; maintains a registry of RES installers.

Over the past two years, Moldova has implemented significant legislative and regulatory reforms aimed at supporting and advancing RES. These measures, based on the European Directive 2009/28/EC and the national Energy Strategy to 2030, include regulatory acts, financial mechanisms, and information and educational campaigns. Key achievements include:

Updating strategies and regulations	Within the framework of the Energy Strategy to 2030 (Decision No. 102 of 05.02.2013) and the new National Energy and Climate Plan, long-term objectives have been developed to support RES. For instance, the Renewable Energy Support Law is currently under revision to create a regulatory framework that enables national target achievement. Such measures aim to facilitate the participation of producers and investors in the RES sector (planned for 2021–2022).
Financial support and incentives	To support renewable energy producers, green tariffs, net metering, and capacity quotas for RES have been introduced, fostering an increase in renewable energy's share in the total energy balance (Decision No. 54/2020). Additionally, a programme of customs and tax exemptions for RES producers is in effect, helping reduce entry barriers to the industry.
Regulation and certification	Regulations have been adopted to oversee tender procedures for RES, guarantee the origin of RES-generated electricity, and certify equipment installers, ensuring a high level of quality and sustainable industry development (e.g., Decision No. 690 of 11.07.2018).
Support for bioenergy	Recently, Moldova has been actively developing a regulatory framework for biofuel production, including the establishment of sustainability standards and methodologies for assessing greenhouse gas emission reductions achieved through biofuel use (measures planned for 2021–2022).
Information and educational initiatives	To raise awareness among the public and investors, informational campaigns, training sessions, and capacity-building programmes are organised, encouraging all stakeholders to engage in the transition to RES. Information-sharing platforms have been established, and public campaigns promoting RES are actively

	supported (e.g., informational support through platforms organised by EEA, starting in 2021).

Thus, a comprehensive regulatory framework has now been established to support RES, encompassing strategic planning, financial incentives, certification, and information campaigns. These measures contribute to achieving national targets for increasing the share of RES and promoting the sustainable development of the energy sector.

3.1.5 ETS System (Emissions Trading System)

Moldova is taking decisive steps to reduce greenhouse gas emissions and align its legislation with European Union standards.

One of the key actions has been the **partial implementation of the European Union Emissions Trading System (EU ETS) Directive** into Moldovan law, with support from the EU and UNDP. In the initial phase, an independent system for monitoring, reporting, and verification (MRV) of emissions was established for 12 major companies with a total installed capacity of approximately 3,300 MW. These include energy companies such as Termoelectrica and CET-Nord, as well as industrial enterprises, including Bucuria SA, Lafarge Ciment Moldova, and others[10].

The **EU4Climate project**, with a budget of €8.8 million (2019–2022), has played a central role in this transformation. The project facilitated the alignment of national legislation with the EU's climate framework, including EU ETS. Given Moldova's commitment to transpose elements of the EU ETS as part of its EU agreements, the project supported the development of a national low-carbon strategy, reinforced emission monitoring systems, and aligned national legislation with EU requirements. **Amendments to the Environmental Protection Law** were adopted to regulate greenhouse gas emission management and issue emission certificates to economic operators[11].

Effective CO_2 emissions monitoring is a critical component of Moldova's energy transition, particularly in light of the ambitious targets to reduce greenhouse gas emissions by 70%[12] by 2030 and achieve carbon neutrality by 2050. With the necessary technical and financial assistance, this reduction could reach **88%**. Notably, the country has already made significant progress, achieving a 69% reduction in emissions.

Moldova has adopted the **Industrial Emissions Act[13]** (integrated environmental permitting) and the MRV Regulations for stationary installations, alongside a full transposition of MRV (EU 2018/2066) and accreditation and verification (EU 2018/2067) regulations. Implementing an independent MRV system for emissions from major energy facilities, including CHP plants, marks the critical step in realising the European ETS Directive. This process takes on added importance with planned construction of new CHP plants and the modernisation of existing cogeneration facilities in Chișinău and Bălți. Plans for developing a decentralised CHP network should be accompanied by the implementation of modern CO_2 emissions monitoring systems, integrated into the national emissions registry under the management of the Environmental Agency. This approach will not only allow tracking of environmental performance of energy-generating facilities but also optimise their operations to maximise energy efficiency.

A landmark event came in April 2024, with the adoption of the breakthrough **Climate Change Law[14]**, through which the country committed to achieving carbon neutrality by 2050. This legislation has laid the foundation for the most comprehensive climate framework in Eastern Europe, the Caucasus, and Central Asia, drawing inspiration from EU climate policy. The new climate law focuses on decarbonising various sectors, including energy, transport, and industry. Moldova is committed to expanding the use of renewable energy, enhancing energy efficiency, and investing in sustainable infrastructure. The full transposition of the ETS Directive and carbon pricing provisions is set to be completed by the 2025.

[10] 12 Large Moldovan Companies to Report Their Greenhouse Gas Emissions
[11] Law of the Republic of Moldavia No. 1515 - XII of June 16, 1993 "On Environmental Protection" (as amended and complemented from November 30, 2023)
[12] Moldova plans to reduce greenhouse gas emissions with EU support
[13] Law No. LP227/2022 "On industrial emissions"
[14] Proiectul de lege privind acțiunile climatice

In the context of sustainable energy system development, **waste-to-energy technologies**, including the use of RDF, hold particular promise. Given that the heating and cooling sector in Moldova already has a significant share of renewable energy (46%), with 27% of consumption accounted for by biomass, integrating RDF-based waste-to-energy technologies could become a valuable additional source of green energy. This approach not only addresses waste management challenges but also helps meet the target of a 1.1% annual increase in the share of renewable energy in the heating and cooling sector by 2030. It will be essential to ensure stringent emissions monitoring from waste-to-energy facilities, including those utilizing RDF, integrating them into the overarching MRV system and regulatory framework.

A comprehensive approach to CO_2 emissions monitoring and waste-to-energy technology development should be an integral part of Moldova's energy sector modernisation. This is particularly relevant given that nearly two-thirds of households still use inefficient individual heating systems. Transitioning to advanced cogeneration and waste-to-energy technologies, supported by a reliable emissions monitoring system, will not only enhance energy efficiency and security, significantly contribute to the country's climate targets in line with EU standards, but also bolster Moldova's industrial competitiveness and attract investment.

3.1.6 Building Legislation

Moldovan legislation on industrial energy facility construction permits is summarized in the table below.

Table 3-6. Legislation on industrial energy facility construction permits

Category	Document	Details
Urban planning and design documentation	Code No. 434 as of 28.12.2023	Urban planning code (Official Journal of the RM No. 41-44 as of 30.01.2024)
	Law No. 1513 as of 16.06.1993	Sanitary and epidemiological protection of the population (Official Journal of the RM No. 009 as of 30.10.1993)
	Law No. 1515 as of 16.06.1993	Environment protection (Journal of the Parliament No. 10 as of 01.10.1993)
	Law No. 93 as of 05.04.2007	Civil Protection and Emergency Situations Service (Official Journal of the RM No. 78-81 as of 08.06.2007)
	Law No. 851 as of 29.05.1996	Environmental expertise and environmental impact assessment (Journal of the Parliament No. 52-53 as of 08.08.1996)
	Law No. 86 as of 29-05-2014	Environmental impact assessment (Official Journal of the RM No. 174-177 as of 04-07-2014)
	Law No. 778 as of 27.12.2001	Geodesy, cartography, and geoinformatics (Official Journal of the RM No. 29-31 as of 28.02.2002)
	ANRE Decision No. 266 as of 20.11.2007	Approval of Electrical Transmission Networks Technical Regulations (Official Journal of the RM No. 188-191 as of 07.12.2007)
	ANRE Decision No. 267 as of 20.11.2007	Approval of Electrical Distribution Networks Technical Regulations (Official Journal of the RM No. 188-191 as of 07.12.2007)
	ANRE Decision No. 423 as of 22.11.2019	Approval of the power network Code (Official Journal of the RM No. 14-23 as of 24.01.2020)
	ANRE Decision No. 420 as of 22.11.2019	Approval of the Code of natural gas networks (Official Journal of the RM No. 14-23 as of 24.01.2020)
Construction and commissioning documentation	Law No. 107 as of 27.05.2016	Electricity (Official Journal of the RM No. 193-203 as of 08.07.2016)
	Code No. 434 as of 28.12.2023	Urban planning code (Official Journal of the RM No. 41-44 as of 30.01.2024)
	Law No. 93 as of 05.04.2007	Civil Protection and Emergency Situations Service (Official Journal of the RM No. 78-81 as of 08.06.2007)

Category	Document	Details
	Law No. 151 as of 09.06.2022	Safe operation of potentially hazardous industrial facilities and technical installations (Official Journal of the RM No. 208-216 as of 15.07.2022)
	Government Decision No. 517 as of 17.07.2024	Approval of the Regulation on construction/reconstruction of power plants (Official Journal of the RM No. 347-349 as of 09.08.2024)
	Government Decision No. 743 as of 06.11.2024	Ensuring the quality of constructions (Official Journal of the RM No. 502-505 as of 03.12.2024)
	ANRE Decision No. 266 as of 20.11.2007	Approval of Electrical Transmission Networks Technical Regulations (Official Journal of the RM No. 188-191 as of 07.12.2007)
	ANRE Decision No. 267 as of 20.11.2007	Approval of Electrical Distribution Networks Technical Regulations (Official Journal of the RM No. 188-191 as of 07.12.2007)
	ANRE Decision No. 423 as of 22.11.2019	Approval of the power network Code (Official Journal of the RM No. 14-23 as of 24.01.2020)

The issuance of construction permits in Moldova is carried out in accordance with legal requirements that specify the procedure, type, and timing of permit issuance. The process of issuing permits, approving designs, and inspecting construction/demolition works is implemented via a one-stop-shop based on the Regulation on the establishment and functioning of the one-stop-shop for construction permits**.**

To begin developing project documentation, the contractor must obtain an Urban Planning Certificate from the City Hall of municipality. The Law "On Permitting Construction Works" (№ 163, with amendments as of 28.12.2023 stipulates that the Project agreed only by the Customer and the Chief Architect of the City Hall, and a verification procedure is also provided (technical verification by an independent expert). However, in practice, to obtain a Construction Permit and for the subsequent commissioning of a facility, coordination from various authorities such as electrical supply, gas, water, telephone, or road agencies and/or companies, namely the Sanitary-Epidemiological Service, Fire Service, Environmental Service, and Exdrupo Directorate are required.

The state supervisory bodies involved in the approval process include the National Center for Public Health/territorial public health centres, the State Environmental Inspectorate, the Civil Protection and Emergencies Service, the National Archaeological Agency, the National Council for Historical Monuments under the Ministry of Culture, the State Enterprise National Institute for Research and Design in the Field of Territorial Improvement, Urban Planning and Architecture "URBANPROIECT", and the Municipal Design Institute "Chişinăuproiect".

Regarding the permitting process, Law of the Republic of Moldova 107/2016 stipulates investors wishing to invest in the construction of a power plant with a capacity of more than 20 MW or in increasing the capacity of an existing CHP plant must obtain a decision/approval from the government in this regard[15]. In addition, a **new Urban Planning and Construction Code** has been adopted to simplify construction procedures[16]. A step-by-step guide to obtaining construction permits and project approvals in Moldova is provided in the table below.

[15] Article 4, Chapter 2 of the Law of the Republic of Moldova 'On Power' No 107 of 27.05.2016
[16] Urban Planning and Construction Code of the Republic of Moldova of December 28, 2023 No. 434 (with amendments and additions as of July 25, 2024)

Table 3-7. Obtaining construction permits and project approvals

No	Step Description	Agency	Time frame	Additional information
1	Obtain an extract from the Cadastre with the cadastral plan of the land plot	Cadastre	9 days	Required for obtaining an Urban Planning Certificate
2	Request and obtain an Urban Planning Certificate	General Direction on Architecture, Urbanism and Land Relations (Municipal Council)	45 days	Required documents include an extract from the Register of immovable property, the identity of the applicant
3	Obtain a geotechnical study/soil test	Private licensed company	9 days	Necessary for determining land bearing capacity
4	Request and obtain clearance from Municipality's Zoning and Road Construction Division	Municipality's Zoning and Road Construction Division	18 days	Required if the building is less than 10 meters from an existing road
5	Request and obtain location clearance from the Fire Department	Fire Department	14 days	Initial procedure for project development, may have associated costs
6	Request and obtain technical conditions from the electricity provider company	Premier Energy	14 days	Required for project design documentation and building permit
7	Request and obtain technical conditions for water and industrial sewage from the Apa Canal	Apa Canal	14 days	Conditions obtained after application submission
8	Request and obtain technical conditions for the sewage system from Exdrupo	Exdrupo	14 days	Separate specifications for rainwater drainage
9	Request and obtain urban planning guidelines (red lines) from the Design Institute of Moldova on Engineering and Research Works	Design Institute of Moldova on Engineering and Research Works or Private Licensed	5 days	Specifies the zoning regulations for the land plot
10	Obtain project clearance from the Chief Architect of the Municipality	Chief Architect of the Municipality	14 days	Approval is required for various sections of project documentation
11	Request and obtain expertise clearance from the Fire Department	Fire Department	8 days	Approval of completed designs and drawings
12	Request and obtain expertise on project documents at the State Service for Verification and Expertise of Projects in Construction	State Service for Verification and Expertise of Projects in Construction	14 days	Internal verification of technical conditions
13	Request and obtain a construction permit from the local Urban Planning Services Agency	Urban Planning Services Agency (Municipality)	10 days	Required documents include an extract from the Register of Immovable Property, an Urban Planning Certificate, project documentation, etc.
14	Notify the construction authorities and the State Construction Inspectorate about the start of construction	Construction Authorities and the State Construction Inspectorate	1 day	At least 5 days before starting construction Written notification is required
15	Hire an external technical supervisor	Licensed Engineer	1 day	A technical commission is required for the acceptance of construction works
16	Request and connect to water and sewage services	Apa Canal	22 days	Inspection and approval are required for connections

No	Step Description	Agency	Time frame	Additional information
17	Request and obtain approval of construction works from the Health Department	Health Department	18 days	Approval is required after completion of construction
18	Request and obtain approval of construction works from the Fire Department	Fire Department	10 days	Approval is required after the completion of construction
19	Request and obtain an occupancy permit from the State Construction Inspectorate	State Construction Inspectorate	60 days	Within 15 days of the guaranteed term provided in the contract Approval from various authorities is required
20	Hire a cadastral surveyor to prepare a report	Licensed Cadastral Engineer	22 days	A boundary determination is required for registration
21	Register the building at the Cadastre	Cadastre	30 days	Seals are placed on blueprints, applicant receives one copy

Source: World Bank Group, Economy profile Moldova

Safety regulations for the construction and operation of CHP plants

The comprehensive set of Safety rules for the operation of electrical installations[17], including construction and operation of CHPP provides exhaustive requirements to minimise risks associated with the design, operation, and maintenance of electrical installations. These guidelines are mandatory for all CHPP construction and operation personnel and encompass organisational and technical measures, along with protective equipment, to ensure occupational safety, fire protection, and adherence to building codes. The primary objective is to establish conditions for safe work practices across all stages of handling electrical installations, reduce the risks of electrical injuries, prevent emergencies, and provide holistic protection for employees, facilities, and the environment.

Organising a Safe Workplace	▪ When preparing a work site for the construction or maintenance of electrical installations, a range of organisational measures must be implemented. These include appointing responsible personnel to ensure safe work practices, issuing access permits to work areas, controlling entry, and supervising the work process. ▪ Areas with live electrical parts must be cordoned off and marked with warning signs. Where it is impossible to eliminate employee exposure to electromagnetic fields, exposure time in such zones must be limited to safe durations.
Adhering to Building Codes and Requirements	▪ At all stages of CHPP construction, compliance with requirements set out in NCM A.08.02:2014 for occupational health and safety must be ensured. When performing excavation work, protective measures for underground utilities and cable lines must be in place. Approved protective equipment must be used for all types of construction and installation activities, including work at height. ▪ Specialised tasks, such as wire installation and insulator mounting, must be carried out in strict accordance with approved process sheets and project-specific work plans that reflect the high safety standards required for such sites.
Fire Safety	▪ Before commencing work in confined areas, such as cable tunnels and ducts, fire protection equipment functionality must be verified. If gas or other hazardous

[17] NE1-02:2019 Safety rules for the operation of electrical installations

	substances are detected, work must immediately cease until the hazard is fully mitigated. ■ Working in confined spaces, including shafts and ducts, requires explosion-proof lighting and forced ventilation systems. Smoking and open flames are strictly prohibited in enclosed areas containing flammable materials.
Occupational Health and Safety	■ All employees engaged in CHPP operations are required to undergo professional training in safety measures, including first aid and safe release of victims from electric shock exposure. ■ Employees authorised to perform unsupervised tasks must hold appropriate qualifications and electrical safety certification relevant to the complexity and voltage level of the installations on which they will be working. ■ For live work (up to 1,000 V), dielectric protective equipment, such as gloves, mats, and insulating stands, must be used. The use of unauthorised tools and equipment is strictly prohibited. ■ These rules and measures safeguard employees from hazards associated with CHPP operations, aiming to minimise the risk of accidents and emergencies at electrical power facilities.

3.2 Strategic Perspective

3.2.1 National Energy and Climate Plan (NECP)

The **National Energy and Climate Plan (NECP) of the Republic of Moldova for the period 2025-2030**[18] is a comprehensive strategic document aimed at decarbonising economic sectors and fulfilling international commitments, primarily those outlined in the 2015 Paris Agreement.

The Plan addresses five key dimensions of energy policy: decarbonisation, energy efficiency, energy security, the internal energy market, as well as research, innovation, and competitiveness.

In the area of decarbonisation, Moldova has undertaken ambitious commitments to reduce greenhouse gas emissions. In March 2020, the country submitted an updated Nationally Determined Contribution (NDC) that includes two scenarios:

- An unconditional emissions reduction of 70% by 2030 compared to 1990 levels (a maximum of 13.6 million tonnes of CO2 equivalent)
- A conditional reduction of up to 88% given additional support

As a member of the Energy Community, Moldova has committed to reducing net greenhouse gas emissions to 9.1 million tonnes of CO2 equivalent by 2030.

In renewable energy, Moldova has set a target to achieve a 27% share of renewables in total energy consumption by 2030. The government forecasts two development scenarios:

- Under current measures, the renewable energy share will reach 25.6%
- With planned measures, this will increase to 31.4%, exceeding the established target

Government Decree No. 401 of 8 December 2021 set a limit for renewable energy capacity at 410 MW by 2025, including 165 MW for large-scale producers on an auction basis.

[18] National Energy and Climate Plan (NECP) of the Republic of Moldova for the period 2025-2030

In the area of energy efficiency, Moldova has committed to capping final energy consumption at 2.80 million tonnes of oil equivalent and primary energy consumption at 3.00 million tonnes of oil equivalent by 2030. Key measures include:

- An annual increase in energy efficiency of 3% in buildings of central public authorities
- Annual savings of at least 0.8% in energy consumption
- A reduction in industrial energy intensity by 51% by 2030

The National Plan encompasses policy measures (see table below), each carefully detailed in terms of objectives, timelines, sectors of influence, responsible institutions, and funding sources.

CHP plants are regarded as a key component for enhancing the country's energy efficiency. In the NECP, they are highlighted among priority measures to improve energy efficiency, particularly in the following areas:

- **Reducing energy losses** in the production of heat and electricity, thereby lowering primary energy resource consumption.
- **Modernising existing facilities** to improve their energy efficiency and bring them into compliance with stricter environmental standards, thus supporting Moldova's greenhouse gas reduction targets.

As part of the energy efficiency measures (policy measure PM_EE22), CHP modernisation holds significant potential for emission reduction by improving efficiency and reducing overall fuel consumption.

Waste-to-Energy technologies support Moldova's NECP objectives in the following ways:

- **Supporting decarbonisation**: WtE technologies help reduce emissions by utilising waste as an alternative fuel source. This not only decreases the carbon footprint associated with traditional energy production but also reduces landfill volumes, contributing to lower pollution levels.
- **Achieving renewable energy targets**: WtE technologies aid in meeting national renewable energy goals by increasing the share of renewable energy in Moldova's energy mix. Integrating WtE into the energy balance, as outlined in the NECP, contributes towards reaching the 27% target for renewable energy in total final energy consumption by 2030.
- **Sustainable waste management**: Under the "Policy Measures" section (PM_DC16 and PM_DC17), Moldova's waste processing strategy and the implementation of municipal solid waste projects (such as the Moldova Solid Waste Project) support sustainable economic practices and circular economy initiatives aimed at waste reduction and resource efficiency.

Both CHP and WtE play a crucial role in advancing Moldova's decarbonisation and energy efficiency objectives, enhancing energy security, and reducing dependence on imported fossil fuels.

Table 3-8. Policy measures of the National Plan

Dimension	Key objectives	Policy measures
Decarbonization	■ **GHG emissions and removals:** – Carbon emissions reduction; – Fulfilling obligations of the Paris Agreement and of the Energy Community; – Contributing to the EnC – 60.9% GHG emissions reduction target with national emissions reduction in 2030; – Attaining the national GHG emissions reduction target for the Right bank of the Dniester River by 68.6% in 2030 compared to the 1990 level. ■ **Renewable energy:** – Attaining the national target for Renewable Energy share in final energy consumption is of 27% in 2030	PM_DC1: Carbon Border Adjustment Mechanism
		PM_DC2: Implementation of an Emissions Trading System
		PM_DC4: Development of the projects of the Joint Credit Mechanism with Japan (JCM)
		PM_DC6: The Low Emission Development Program of the Republic of Moldova until 2030 and the Action Plan for its implementation
		PM_DC7: Preparation for and introduction of carbon tax
		PM_DC8: Implementation and monitoring of the Low-Carbon Development Program until 2030 and of the Action Plan for its implementation and of the National Climate Change Adaptation Program until 2030 and the Action Plan for its implementation
		PM_DC9: The program for the promotion of the green and circular economy for the years 2024–2028
		PM_DC10: Law on Climate Actions
		PM_DC14: Substitution of clinker in the cement production
		PM_DC15: Environment Strategy until 2033
		PM_DC16: Waste Management Strategy 2013-2027
		PM_DC17: Moldova Solid Waste Project
		PM_DC18: Implementation of the "no-till" and mini-till conservative tillage system
		PM_DC19: Implementation of sustainable agricultural land management practices
		PM_DC20: Manure storage in communal platforms or individual warehouses
		PM_DC21: Promotion of cattle feeding technologies by using feed in the form of unique mixtures (monoration) without or with small amounts of green fodder
		PM_DC22: Promoting the use of grape marc in ruminant rations with the aim of reducing greenhouse gas emissions
		PM_DC26: Amended Law on promotion and use of renewable energy sources
		PM_DC27: Support scheme based on fixed prices
		PM_DC28: Support scheme based on fixed tariff
		PM_DC29: Support scheme based on net metering
		PM_DC30: Fostering deployment of RES in district heating
		PM_DC31: Promotion of heat pumps for the Heating & Cooling sector
		PM_DC32: Promotion of sustainable green cities for Moldova
		PM_DC33: Promotion of biofuels and bio-liquids
		PM_DC34: Promotion of the electrification of road and rail transport
		PM_DC35: Promotion of green technologies in private sector
		PM_DC36: Promotion of energy efficiency in SME
		PM_DC37: Promotion of innovative technologies in SME
		PM_DC38: Promotion of Rural Competitiveness and Resilience

		PM_DC39: Promotion of energy communities
		PM_DC40: Promotion of biomass for electricity production
		PM_DC41: Action Plan for implementing the Roadmap for preparing and instituting carbon pricing in the Republic of Moldova
		PM_DC42: Promotion of the national process of planning the adaptation of the Republic of Moldova to climate change (Stage 2)
		PM_DC44: Promotion of fiscal incentives for electrical vehicles
	Ensuring the institutional framework for coordination in the area of monitoring, reporting and verification, as well as facilitating the integration of climate change aspects into national and sectoral programs and plans	PM_DC3: Climate Change Coordination Mechanism
	Specific objective 5: *"Increasing the resilience of priority sectors by financing activities in the field of adaptation to climate change and reducing the risks and negative impacts of climate hazards"*; Priority action 5.2: *"Increasing the energy efficiency and resilience of the energy sector infrastructure by adjusting to forecasted hydro-meteorological parameters"*	PM_DC5: The National Climate Change Adaptation Program until 2030 and the Action Plan for its implementation
	Reduction of Pollution and GHG emissions	PM_DC11: Development of the secondary regulatory framework for the implementation of the Industrial Emissions Law no. 227/2022
	F-gases emissions reduction	PM_DC12: Law on fluorinated greenhouse gases
	To manage usage, identify energy saving opportunities, conserve consumption and reduce carbon emissions	PM_DC13: Implementation of the energy management system according to the Moldovan Standard SM EN ISO 50001: 2019
	Increase of carbon removals	PM_DC23: Land afforestation
		PM_DC24: Creation of forest protection curtains
		PM_DC25: Planting of energy forestry crops
	Pollutant emissions reduction	PM_DC43: Promotion of considerable reductions in fine particle emissions and black carbon from roads
Energy Efficiency	▪ Contribution to attaining the national target for energy consumption is of 2.80 Mtoe in the Final Energy Consumption in 2030.	PM_EE1: Residential Building Refurbishment
		PM_EE2: Public Sector Building Refurbishment
		PM_EE3: Creation of databases (inventories) on the stock of buildings
		PM_EE4: Conducting a market assessment for the cost-optimal level of refurbishment
		PM_EE5: Development of the missing parts for the calculation methodology and minimum energy efficiency requirements for new and rehabilitated buildings

	▪ In terms of maximum Share of Primary Energy Consumption, the target is of 3.00 Mtoe in 2030. ▪ Implementation of the Directive (EU) 2012/27, as amended by Directive (EU) 2018/2002, Law on Energy Performance of Buildings. ▪ Assessment of the implementation of Law No. 139/2018 on Energy Efficiency. ▪ Implementation of the Law No. 139/2018 on Energy Efficiency, transposition and implementation of Directive (EU) 2012/27/EU as amended by Directive (EU) 2018/2002. ▪ Reduce greenhouse gas emissions and enhance climate resilience in the buildings sector, increase share of RES in electricity, increase share of RES in heating and Cooling. ▪ Consumer protection and improvement of competition, enable EE at the supply side (i.e. through the reduction of losses).	PM_EE6: Creating a National Energy Efficiency Information System
		PM_EE7: Introducing energy efficiency certification of buildings (for inspection of heating/ventilation and air conditioning systems), adopt a plan for practically zero-energy buildings, etc.
		PM_EE8: Fully transpose the provisions of the EU's Energy Performance of Buildings Directive (EPBD)
		PM_EE11: Promotion of energy services and energy performance contracts
		PM_EE12: Creation and development of the field of energy services, financial instruments and energy audit
		PM_EE13: Development of a national program for the renewal of the vehicle fleet by introducing a differentiated environmental fee depending on the level of pollution
		PM_EE14: Supporting the development of incentives for the import of electric and hybrid vehicles, as well as the development of national infrastructure required for electric vehicles, charging points and parking infrastructure
		PM_EE15: Create initiatives to support the transition of residential and urban public transport or freight transport to hybrid or electric vehicles
		PM_EE16: Increase in the share of rail transport
		PM_EE17: Promoting sustainable mobility
		PM_EE18: Implementation of a mandatory energy audit and ISO 50001 certification according to the Moldovan Standard SM EN ISO 50001: 2019
		PM_EE19: Implementation of requirements for energy labeling for products of energy impact
		PM_EE20: Introduction of obligations on environmental procurement
		PM_EE21: Promoting of universal street lighting with a priority based on the supply from RES
		PM_EE22: Promoting/modernizing highly efficient CHP units
		PM_EE23: Modernizing of district heating networks
		PM_EE24: Promotion of measures for improving energy efficiency in electricity infrastructure
		PM_EE25: Promotion of measures for improving energy efficiency in natural gas infrastructure
		PM_EE26: Development of sustainable and innovative financing of energy efficiency projects
		PM_EE27: Improve the bankability of energy efficiency projects
		PM_EE9: Creation of financial mechanisms to support the environmental repair of apartment buildings and individual residential buildings, including with the integration of renewable energy sources
		PM_EE10: Implementation of smart metering systems and other advanced metering technologies to better respond to demand, remote metering and real-time consumption-based energy/gas billing

3.2.2 Energy Strategy of Moldova

Moldova is set, for the next years, to ensure the country's energy independence and the citizens' supply with accessible energy, both in terms of source and price. This goal is seen in the Concept of Moldova's Energy Strategy till the 2050 year, approved by the State Chancellery – a document of policies, which establishes priorities in the energy sector by the middle of the 21st century[19].

Moldova's long-term energy strategy outlined in the *Sustainable Energy Transition Roadmap to 2050* focuses on achieving a carbon-neutral, resilient, and energy-secure future. Key areas include the integration of combined heat and power systems, renewable energy, and a strategic reduction in reliance on imported fuels, aligning with both environmental goals and national energy security[20].

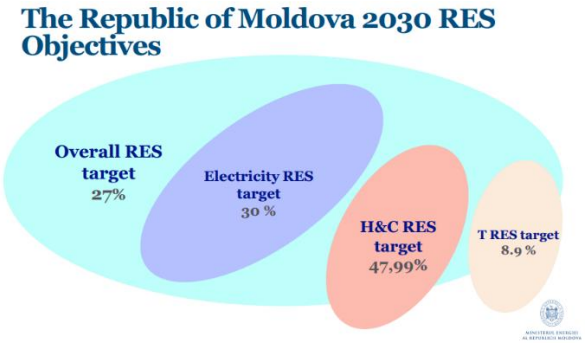


Figure 3-1. RES objectives

As part of the energy transition, the country intends to gradually electrify domestic heating. Various methods must be considered, including high-efficiency heating - using heat pumps, using existing thermal power plants in combination with heating (combined heat and power - CHP), adapted for green H2 and CH4, etc. These solutions need to be complemented by measures to increase the efficiency of heat consumption through modernisation (renovation of existing installations), implemented at the level of heating installations (at source), at the level of heat transport and at the level of buildings (at end users).

3.2.3 Waste Management Plan

Waste management in the Republic of Moldova is undergoing significant transformation, driven by the adoption of Law No. 209 "On Waste" dated 29 July 2016[21], alongside subsequent strategic documents.

Presently, the country operates approximately 1,136 landfill sites spanning a total area of 1,276.67 hectares, though most of these sites fall short of modern environmental standards. Statistics indicate a steady increase in the volume of municipal solid waste: from 2,172.80 thousand m^3 in 2008 to 3,311.4 thousand m^3 by 2021[22]. Despite existing regulations, around 90% of collected municipal waste continues to be deposited in landfills, with selective waste collection systems only partially implemented in Chisinau and a few district centres.

Environmental challenges are especially pronounced in the context of climate change. In 2021, the waste sector accounted for approximately **10.2% of greenhouse gas emissions**, significantly surpassing the global average of 3%. This situation could have serious repercussions for Moldova's

[19] EU4Climate. Republic of Moldova
[20] Sustainable energy transition roadmap to 2050 for republic of Moldova
[21] Law No. 209 "On Waste" dated 29 July 2016
[22] National Energy and Climate Plan (NECP) of the Republic of Moldova for the period 2025-2030

agriculture, water resources, and public health. A pivotal step in addressing these issues was the Moldovan Government's adoption of Decree No. 972 on 6 December 2023, approving the **National Waste Management Plan for 2023-2027**[23], which came into force on 6 March 2024. The core aim of this document is to develop an integrated waste management system that is both economically efficient and protective of environmental and public health.

The National Plan provides a comprehensive approach to addressing environmental issues. Its primary objectives include developing infrastructure to prevent pollution, reducing the amount of landfilled waste, increasing recovery and recycling rates to **40-60%** for products covered under the extended producer responsibility regime, and enhancing public awareness.

Particular emphasis is placed on the adoption of waste-to-energy (WtE) technologies. These technologies reduce landfill waste and support energy production through incineration, anaerobic digestion, and gasification processes. Moreover, CHP plants play a strategic role in this system, enhancing energy efficiency and reducing greenhouse gas emissions. Implementing WtE technologies and modernising the waste management system allows Moldova to achieve several key objectives:

- lowering greenhouse gas emissions,
- increasing the share of renewable energy,
- reducing dependence on imported fuels, and
- improving the country's environmental conditions.

In this way, these measures demonstrate a consistent and holistic approach to waste management challenges, addressing both environmental concerns and establishing a foundation for the sustainable development of the Republic of Moldova.

3.2.3.1 Waste to Energy Utilization Possibilities in the Republic of Moldova

The opportunity to utilize waste-to-energy (WtE) with the new Combined Heat and Power (CHP) generation capacity in Chisinau appears promising based on the study. Here are the key points:

1. **Waste Composition and Heating Value:**
   - The study provides a detailed analysis of the waste composition in Chisinau, including proximate and elemental analysis.
   - The heating value of the waste is a crucial factor for energy recovery potential. The report includes specific heating value results for Chisinau, which are essential for evaluating the feasibility of WtE projects.
2. **Energy and Electricity Potential:**
   - The study estimates the energy and electricity potential from municipal solid waste (MSW).
   - This estimation helps in understanding how much energy can be recovered and utilized in new CHP facilities, enhancing energy security and efficiency.
3. **Waste Generation Forecast:**
   - Projections of waste generation are provided, which are vital for planning the scale and capacity of WtE facilities.

[23] Decree No. 972 on 6 December 2023 National Waste Management Plan for 2023-2027

- Understanding future waste trends allows for the design of scalable and adaptable energy solutions.

4. **Infrastructure and Environmental Impact:**

   - Integrating WtE with CHP can improve energy efficiency by utilizing both electricity and heat.

   - The environmental benefits include reduced landfill usage and greenhouse gas emissions.

Overall, the study supports the viability of integrating WtE with new CHP generation in Chisinau, given the substantial energy potential of the available waste and positive environmental impacts. Further detailed feasibility studies would be needed to address specific technical and economic aspects.

The opportunity to utilize waste-to-energy (WtE) with the new Combined Heat and Power (CHP) generation capacity in Chisinau is substantial and merits a comprehensive assessment based on the findings from the Waste Characterization Study. This evaluation not only highlights the potential benefits but also outlines the necessary steps and considerations for implementation.

Overview of Waste Composition

The Waste Characterization Study conducted by Tetra Tech ES, Inc. provides critical insights into the composition of municipal solid waste (MSW) in Chisinau. The survey included a thorough analysis of the waste, which is essential for understanding the energy content and suitability for WtE applications. The study outlines the various waste fractions, including organic material, plastics, metals, and other recyclables. Understanding these fractions allows for the optimization of waste sorting and treatment processes, ultimately enhancing the efficiency of energy recovery.

Heating Value and Energy Potential

One of the vital aspects of the WtE process is the heating value of the waste. The report indicates that the heating value for the waste generated in Chisinau is favorable for energy production. This is crucial because a higher heating value translates to more energy that can be extracted during the combustion process. The study details the proximate and elemental analyses, which provide essential data for estimating the energy and electricity potential from the waste stream.

The estimation of electrical power potential (EPP) and energy potential (EP) from MSW is particularly significant. The study forecasts that with proper management and infrastructure, a considerable amount of energy can be produced, which not only supports local energy needs but also contributes to reducing dependence on fossil fuels.

Waste Generation Forecast

The report also includes a waste generation forecast, projecting future waste volumes based on population growth and urbanization trends in Chisinau. This forward-looking approach helps in planning the necessary infrastructure and capacity of WtE facilities. By anticipating increases in waste generation, stakeholders can ensure that the CHP systems are adequately designed to handle the projected waste flow, thereby maximizing energy recovery and operational efficiency.

Environmental and Economic Benefits

Integrating WtE with CHP technologies presents numerous environmental benefits. Utilizing waste for energy reduces the volume of waste sent to landfills, thereby mitigating environmental pollution and greenhouse gas emissions associated with waste disposal. Moreover, the dual production of electricity and heat enhances energy efficiency, making better use of the available waste resources.

From an economic perspective, developing a WtE facility can stimulate local job creation during both the construction and operational phases. Additionally, it can lead to lower energy costs for consumers by providing a stable, local source of energy.

Challenges and Considerations

While the potential for WtE in Chisinau is promising, several challenges must be addressed. These include the need for significant upfront investment in infrastructure, public acceptance of waste management practices, and adherence to environmental regulations. Engaging stakeholders, including local communities and government bodies, will be essential for overcoming these challenges.

Conclusion

In summary, the integration of waste-to-energy systems with new CHP generation capacity in Chisinau represents a viable opportunity to enhance energy security, reduce environmental impact, and foster economic growth. The findings of the Waste Characterization Study provide a solid foundation for moving forward with such initiatives. Further feasibility studies and stakeholder engagement will be crucial to realizing the full potential of this opportunity.

By leveraging the insights from this comprehensive report, Chisinau can position itself as a leader in sustainable waste management and renewable energy generation, setting a precedent for other municipalities in the region.

3.2.3.2 Industrial Emissions

Law 227/2022 establishes the legal framework for preventing and controlling pollution from industrial activities in Moldova, in line with EU environmental standards. Coming into force in October 2022 (with amendments in early 2025 to harmonize related legislation), this law adopts an integrated pollution prevention and control approach mirroring the EU Industrial Emissions Directive. Its core aim is to minimize harmful industrial emissions to air, water, and soil and to reduce waste generation at source, thereby protecting environmental and public health. Key principles and provisions include:

- **Pollution prevention and integrated permitting**: The law mandates that industrial installations operate only under an integrated environmental permit that covers all environmental emissions and impacts of a facility. This replaces the old system of separate permits (for air emissions, wastewater discharges, and waste management) with a single, consolidated permit per installation, greatly simplifying procedures and ensuring a holistic oversight of pollution. By addressing emissions to air, water, and soil jointly and by promoting waste prevention, the law seeks to prevent pollution at the source rather than just control it after the fact.
- **Best Available Techniques (BAT)**: A cornerstone of the law is the requirement for operators to apply the Best Available Techniques (BAT) in their processes and pollution abatement measures. Permit conditions and emission limit values must be based on BAT conclusions, ensuring that industries use up-to-date, efficient technologies to minimize emissions. This principle drives continuous environmental improvement and technological innovation, as firms must upgrade to cleaner techniques in order to comply. Generally binding rules may be issued for certain sectors, and emission limit values are set in line with EU BAT standards for pollutants.
- **Compliance monitoring and enforcement**: The law introduces a comprehensive system for monitoring compliance with permit conditions. Industrial operators are subject to periodic environmental inspections (including unannounced inspections) and must self-monitor and report emissions as stipulated by their permits. Environmental authorities develop control plans and have powers to suspend or revoke permits if violations occur. Strengthened enforcement provisions, including penalties and environmental liability for non-compliance, ensure that the pollution prevention measures are effectively implemented on the ground.
- **Alignment with EU directives and transition measures**: Law 227/2022 is closely aligned with European Union directives – it partially transposes the EU Industrial Emissions Directive 2010/75/EU and fully implements the Medium Combustion Plant Directive (2015/2193). By adopting EU-aligned standards (for instance, BAT-based emission limits and public participation in permitting decisions), the law supports Moldova's EU accession and the broader "zero pollution" goals. Recognizing that existing installations may need time to upgrade, the law includes transitional provisions (up to two years from entry into force)

for operators to meet the new requirements. During this phase, companies must prepare compliance plans and obtain the necessary integrated permits within the set deadlines.

In summary, Law No. 227 creates a modern regulatory framework for industrial emissions that is future-oriented and sustainability-focused. It shifts Moldova's industrial regulation from media-specific pollution permits to an integrated system that encourages cleaner production and accountability. For the energy sector and other industries, this means new high-efficiency plants must be designed to BAT standards, and older facilities will need retrofits or operational changes to reduce emissions. This law thus complements the country's energy transition and climate goals by ensuring that as Moldova pursues high-efficiency heat and power generation, those facilities operate with minimal environmental impact, in harmony with European best practices on pollution prevention. The result is a proactive legal environment that drives sustainable industrial development while protecting air and water quality for communities.

3.3 Additional Considerations

3.3.1 Renewable Energy Integration

Moldova's potential for renewable energy is substantial and can be leveraged in both centralised and decentralised heating systems. For instance, the country has untapped geothermal potential (particularly in thermal springs with water temperatures of 30-50 °C), as well as solar thermal energy and excess (waste) heat, which could be utilised at both the household level and within existing heating networks.

Existing renewable energy capacities as of January 2023:

- **Wind installations (56%)** – 115.10 MW
- **Solar power plants, including net metering systems (29%)** – 60.13 MW
- **Hydropower plants (8%)** – 16.25 MW
- **Biogas cogeneration plants (7%)** – 15.33 MW

Solar installations demonstrated substantial growth in electricity generation capacity, with solar power plants, including net metering, rising from 4.02 MW in 2018 to 60.13 MW in 2022—an almost 15-fold increase over five years.

Wind energy installations also experienced significant expansion, with electricity generation capacity nearly tripling from 35.6 MW in 2018 to 115.1 MW in 2022.

Biogas cogeneration plants increased their electricity generation capacity by almost 2.7 times, from 5.7 MW to 15.3 MW.

Regarding the development of renewable electricity production, the country's climate and landscape are favourable for the establishment of profitable **wind and solar power plants**. The average annual solar energy potential in Moldova is estimated at a fairly high level – **1,200 kWh/m²**[24]. These figures confirm the republic's significant potential.

In the **heating and cooling sector**, Moldova has already achieved substantial progress: as of 2017, the share of renewable energy accounted for approximately **46%** of total final energy consumption, with **27%** from biomass. By 2021, biomass combined with fossil fuels supplied **48%** of heating

[24] Crisis as an opportunity for qualitative transformation of Moldova's energy sector

needs[25]. According to the National Energy and Climate Plan, an annual increase of **1.1%** in the share of renewable energy in the heating and cooling sector is planned from 2023 to 2030[26].

The Moldovan government actively supports the development of renewable energy. According to Decision No. 401 dated 8 December 2021, substantial expansion in generating capacity is planned by 2025[27]:

- an additional 120 MW from wind power,
- 200 MW from photovoltaic installations, and
- 90 MW from cogeneration plants using biomass, biogas, and waste.

The total green capacity in wind and cogeneration is expected to reach approximately **350 MW**. Significant progress in implementing these plans is already evident: in 2023, the installed capacity of renewable energy power plants doubled, reaching **343 MW[28]**.

3.3.1.1 Moldova Biomass Potential

The potential of using the biogas as energy source for electrical energy and energy for heating purposes is based on the analyses of the document 'Study of Moldova's Biomass Potential', financed by UNDP. The document addresses the **permanent increase in the price of sunflower husk**, which is identified as a primary source of raw material. This trend is significant for the **national economy** as it is anticipated to contribute positively to the growth of the nation's GDP. However, the document also highlights several critical issues obstructing progress in the biomass sector:

- **Lack of Enforcement of Environmental Legislation**: There is a noted deficiency in enforcing environmental laws related to biomass that arises from maintenance activities. This lack of enforcement may hinder sustainable practices and the responsible management of biomass resources.

- **Biomass Categorization**: The document categorizes biomass sources by sector (public and private), by type (woody and herbaceous), and by origin (including specially cultivated short-cycle crops or biomass generated from agricultural or manufacturing activities). Each category plays a vital role in the overall biomass landscape of Moldova.

- **Support for Biofuel Producers**: There is a **lack of policies** aimed at supporting biofuel producers and biomass processors. This gap in policy development could stifle innovation and the growth of sustainable energy solutions.

It is proposed to conduct a **complex analysis of biomass energy sources** across various sectors of the national economy. It will explore the avenues available for consuming this biomass, considering both its raw form, such as chopped wood, and its processed forms, including pellets and briquettes.

- **Promotion of Biomass Energy**: It is identified a **lack of massive promotion of biomass energy**. Furthermore, it is noted that the need for increased state investment in transitioning from fossil fuels to solid biofuels, as the state continues to rely heavily on traditional energy sources like natural gas, and fuel oil.

The success of these initiatives depends heavily on the **availability of sufficient raw materials** and the existence of **combustion technologies** that meet necessary technological requirements.

[25] Renewable energy solutions for heating and cooling systems in Moldova
[26] Recommendations on the draft integrated National Energy and Climate Plan of the Republic of Moldova covering the period 2025-2030
[27] Renewable energy
[28] Viktor Parlikov: We have every chance to become part of the European energy market even before joining the EU

Notably, the high price of solid biofuels compared to natural gas presents a significant barrier to entry for consumers.

The development of the biomass sector has been influenced by various factors, including the availability of fossil fuels and biofuels derived from biomass. Moldova possesses adequate quantities of diverse biomass types, which could potentially enable the total substitution of certain fossil fuels, such as coal, thereby providing energy resources to a substantial segment of the population.

Particularly noteworthy is the **industrial sector**, which, as of now, has adopted very few green technologies but holds immense potential for future developments. Additionally, there exists a promising opportunity for centralized thermal energy producers, such as **Termoelectrica SA**, to leverage biomass resources effectively.

The **solid biofuel sector** has witnessed significant fluctuations, experiencing a remarkable rise between **2012 and 2017**, followed by a persistent decline that continues to the present day. This decline raises concerns about the sustainability of biomass energy initiatives.

It is essential to understand that the **price of biomass products** relative to their quality is a crucial factor determining demand and consumption. The raw materials needed for biofuel production are pivotal in establishing a balance in the market, especially in light of the lack of **diversification policies** regarding raw materials.

One of Moldova's major opportunities lies in the **decarbonization of the economy** through the development of the biomass energy sector. This initiative commenced in the early 21st century, supported by projects financed by external donors and implemented by **UNDP Moldova**. The biomass energy sector saw its most substantial growth with the **"Energy and Biomass" project**, financed by the European Union and executed by UNDP Moldova. This project notably facilitated the provision of thermal energy to **320 public institutions**, including schools, kindergartens, and cultural centers, thereby enhancing public service efficiency.

In addition to providing energy, the project laid the groundwork for effective biomass management and its transformation into new marketable products, such as pellets and briquettes. Over the span of **12 years**, substantial progress has been made in this field.

The document also references Moldova's commitments concerning energy and climate, emphasizing the importance of maintaining **green spaces** and sustainable agricultural practices.

To accurately determine the quantity of energy that can be derived from biomass in Moldova, a comprehensive approach is required. This involves several steps that encompass assessing biomass availability, understanding energy content, evaluating conversion efficiencies, and finally, calculating the potential energy output. Here's a more detailed breakdown:

1. Assess Biomass Availability

a) **Agricultural Residues**: Moldova has a significant agricultural sector, which produces various crop residues. Key crops include grains (wheat, barley, maize) and oilseeds (sunflower). Each of these crops generates a substantial amount of biomass in the form of straw, husks, and stalks.

b) **Forestry Resources**: The forestry sector can contribute biomass from wood processing residues, such as sawdust, wood chips, and bark. Additionally, sustainable forest management practices can provide a steady supply of biomass.

c) **Animal Manure**: Livestock farming produces manure, which can be processed through anaerobic digestion to produce biogas, a valuable form of renewable energy.

d) **Organic Waste**: Municipal solid waste and agricultural waste can also be considered as biomass sources. This includes food waste, yard trimmings, and other organic materials.

2. Determine Energy Content

Energy Content of Biomass Types: Different biomass types have varying energy contents, typically measured in megajoules per kilogram (MJ/kg). For example:

- **Straw**: Approximately 14-18 MJ/kg
- **Wood**: Approximately 15-20 MJ/kg (depending on moisture content)
- **Biogas**: Approximately 20-25 MJ/m³, depending on the composition

Understanding the specific energy content of each biomass type available in Moldova will aid in calculating the potential energy yield.

3. Conversion Efficiency

a) **Conversion Technologies**: Biomass can be converted into energy through various technologies, each with a different efficiency rate:

- **Direct Combustion**: Typically has an efficiency of 75-90% for heat production.
- **Anaerobic Digestion**: The efficiency can range from 50-70% depending on the substrate and technology used.
- **Gasification**: Generally, has an efficiency of around 70-85% for producing syngas.

b) **System Design and Operation**: The overall efficiency will also depend on the design of the biomass energy system, operational practices, and maintenance.

4. Considerations and Next Steps

To arrive at a reliable estimate, Moldova would need to:

- Conduct field surveys to quantify available biomass resources accurately.
- Collaborate with research institutions to analyze the energy content of local biomass types.
- Evaluate existing technologies and possibly invest in new, more efficient systems to maximize energy yield.
- Consider environmental and economic factors, ensuring that biomass energy projects are sustainable and beneficial to local communities.

Conclusion

The potential for biomass energy in Moldova is significant, given the country's agricultural output and natural resources. By systematically assessing biomass availability, energy content, and conversion efficiencies, Moldova can develop a robust biomass energy strategy that enhances energy security, promotes rural development, and contributes to environmental sustainability.

3.3.2 Cogeneration and Sustainability

As early as 2002, during the development of the National Programme for the Modernisation and Decentralisation of Heating Systems in the Republic of Moldova's settlements[29], technical and economic comparisons were conducted across 5 to 7 options for modernisation in each of the 36 towns/cities. Specialists from leading design and research institutes evaluated various configurations, energy production sources, fuel types, and more. The primary criterion was to reduce the tariff on thermal energy. The analysis revealed that **cogeneration is the only feasible approach for significantly lowering the tariff**. This **reduction in thermal energy tariff is made possible by generating revenue from selling electrical energy at the current tariff rate**.

Based on the results of the technical and economic analysis, cogeneration was recommended as a strategic direction for Moldova's energy sector development. Similar conclusions and recommendations are reflected in subsequent state programme documents:

- Programul Naţional de gazificare al Republicii Moldova. Executant IP „Gazproiect" SA, or. Chişinău. a. 2002.
- Concepţia privind renovarea sistemului de termoficare al Republicii Moldova. Ministerul Energeticii al Republicii Moldova. Chişinău. 2002.
- National Territory Development Plan. Resolution of the Government of the Republic of Moldova No. 1362 of 07.12.2001.

The thermal energy sector in the Republic of Moldova, which covers the production and supply of heat for building heating and hot water provision, is undergoing substantial modernisation. The primary heat producers currently are SA "Termoelectrica", SA "CET-Nord", which predominantly use fossil fuel—natural gas. In parallel, there are opportunities to use renewable energy sources, including biomass, geothermal energy, and waste-to-energy technologies.

High-efficiency cogeneration is strongly promoted under key EU frameworks, including the **Energy Efficiency Directive (2012/27/EU)**, the recast **Renewable Energy Directive (EU 2018/2001)**, and the **Clean Energy for All Europeans package**. By generating electricity and useful heat simultaneously, modern cogeneration technologies:

- Reduce primary energy consumption and associated greenhouse gas emissions;
- Enhance system flexibility by providing on-demand balancing capacity for intermittent renewables;
- Lower distribution losses and improve local energy resilience;
- Remain economically viable through efficient fuel use and lower operating costs.

Such an approach ensures a feasible and sustainable energy solution that strengthens supply security, facilitates further modernisation, and supports the EU's broader decarbonisation targets.

Special emphasis is placed on the development of cogeneration technology that enables the simultaneous production of heat and electricity at a single facility. CHP plants, using natural gas or alternative fuels, can significantly increase resource efficiency by using the heat generated during electricity production for thermal energy generation.

[29] National program for the renewal and decentralization of heat supply systems in populated areas of the Republic of Moldova. Resolution of the Government of the Republic of Moldova No. 1059 of August 29, 2003

In 2023, Moldova made significant strides in stabilising energy security, laying the groundwork for further reforms. In 2024, the country focused efforts on improving energy efficiency by strengthening the Energy Efficiency Fund, actively promoting district heating and cogeneration policies, promoting renewable energy and reducing reliance on natural gas.

Moldova's cogeneration development strategy aims to achieve several key goals: reducing costs, increasing the energy efficiency of heat production and distribution systems, decreasing dependence on fossil fuels, and cutting greenhouse gas emissions in line with national and international climate commitments, promoting connection of existing and new consumers to district heating systems (instead of using gas boilers).

A critical aspect of this strategy is the development of a differentiated approach to heating supply, establishing clear principles for heating provision in urban areas while simultaneously creating alternative solutions for rural regions. This comprehensive approach will foster a sustainable and efficient heating system that meets the needs of all regions across the country.

3.3.3 Climate Action

This landmark climate law (**No. 74/2024**) establishes a comprehensive framework for Moldova's transition to a low-carbon and climate-resilient economy. It codifies ambitious national climate targets – notably a 70% reduction in greenhouse gas (GHG) emissions by 2030 (versus 1990 levels) and climate neutrality (net-zero emissions) by 2050. Aligned with the Paris Agreement and the EU Green Deal objectives, the law embeds sustainable development principles and integrates climate action across all sectors of the economy. Key provisions and forward-looking elements include:

- **National targets and principles**: Enshrines Moldova's long-term vision of reaching climate neutrality by 2050, setting legally binding emission reduction targets and interim goals. It reaffirms the "polluter pays" principle and introduces a carbon pricing mechanism to drive emissions cuts. These measures are designed to spur innovation and cleaner technologies by attaching a financial cost to carbon pollution.
- **Governance and planning**: Establishes a high-level National Commission on Climate Change to coordinate climate policies and actions across government. This inter-institutional body, operating under the Prime Minister's office, is responsible for integrating climate objectives into socio-economic development plans, approving climate-related projects, and ensuring transparency in implementation. The law mandates the development of strategic documents such as a long-term Low-Emission Development Strategy and National Adaptation Programme, and it requires "climate budgeting" practices – i.e. planning and allocating financial resources toward climate goals and resilience-building.
- **Obligations for sectors**: The Climate Action Law calls for economy-wide GHG mitigation efforts, with emphasis on decarbonizing the energy, industrial, transport, and agricultural sectors. Sector ministries and industries must formulate and implement emission-reduction measures consistent with national targets. For example, the energy sector is urged to expand renewable energy and improve efficiency, while industry is steered toward cleaner production methods. These obligations ensure that the energy transition (shifting to low-carbon, efficient energy systems) is accelerated in line with Moldova's climate commitments.
- **Monitoring and enforcement**: The law creates robust mechanisms for monitoring, reporting, and verification (MRV) of emissions and climate actions. It establishes a National GHG inventory and requires regular progress reporting on mitigation and adaptation measures. Provisions on transparency guarantee public access to information on climate policies and their outcomes. To enforce compliance, the framework includes liability for violations and empowers authorities to hold emitters accountable. These tools, together with the long-term signals (2050 net-zero goal and interim budgets/targets), provide predictability and encourage innovative climate solutions (e.g. technological innovation and climate-friendly investments) by public and private actors.

Overall, Law No. 74 is a forward-looking and innovative legal foundation for Moldova's climate policy. It not only sets clear long-term targets but also puts in place the institutions and instruments (like

climate coordination bodies, carbon pricing, and integrated planning) needed to drive a sustainable energy transition and meet international commitments. By linking national development strategies with climate action, the law ensures that future economic growth will be pursued in a climate-responsible and resilient manner, laying the groundwork for climate-neutral, sustainable development.

4. Financial analysis of Termoelectrica S.A.

4.1 Company Overview

4.1.1 General Information

Termoelectrica S.A. is a large public interest entity focused on producing thermal and electric energy for profit. The company operates centralized thermal energy supply systems, promotes cogeneration technologies, and distributes thermal and electric energy to consumers.

Full/short name	Joint-stock company "Termoelectrica" (Societatea pe Acţiuni "TERMOELECTRICA")/Termoelectrica S.A.
Organizational and legal form	Joint-stock company
Incorporation date	16.06.2015
Type of activity	3530: Steam and air conditioning supply 40110: Electricity generation 40301: Thermal energy generation by thermal power plants
VAT registration number	0400008
Fiscal code (IDNO)	1003600026295
Unique identification code (CUIIO)	5696271
Legal address	MD-2024, 6 Tudor Vladimirescu St., Chisinau municipality, Republic of Moldova
Contact information	Tel.: (+373) 022 43-64-59 e-mail: anticamera@termoelectrica.md Website: https://termoelectrica.md

Source: official website of Termoelectrica S.A

Termoelectrica S.A., with over 1,700 skilled employees, is the main producer and supplier of electric and thermal energy in Chisinau and its suburbs, serving around 500,000 consumers across 5,678 buildings, including residential, educational, medical, and commercial facilities. As Moldova's leading cogeneration electricity producer, Termoelectrica supplies approximately 650 million kWh annually, accounting for 15% of the country's electricity consumption. The company operates under licenses from the National Energy Regulatory Agency for producing, distributing, and supplying thermal and electric energy. Additionally, Termoelectrica supplies about 1.3 million Gcal of thermal energy each year through its network of urban and suburban thermal plants.

4.1.2 Organisational Structure

According to the Statute of Termoelectrica S.A., the management bodies of the Company are as follows:

The General Meeting of Shareholders

The supreme governing body of the Company, empowered to make decisions on all matters within the limits established by Moldovan legislation and the Company's Statute.

Board of Directors

Represents the interests of shareholders between General Meetings, overseeing general management and control of the Company's activities within its authority. Subordinate to the General Meeting of Shareholders and responsible for the Company's financial performance.

General Director

Acts as the executive body, managing all daily operations on behalf of the Company, except for matters within the jurisdiction of the General Meeting of Shareholders or the Board of Directors. Reports to the Board of Directors.

Censors Commission

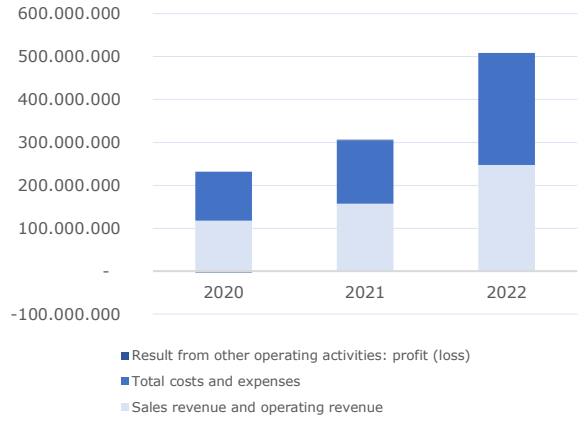
Supervises the economic and financial activities of the Company and reports exclusively to the General Meeting of Shareholders.

4.2 Financial Statements Analysis

4.2.1 Balance Sheet Analysis

Analysis of the economic and financial indicators

The company, classified as a large entity under Law No. 287 (2017) on accounting and financial reporting, prepares financial statements per International Financial Reporting Standards (IFRS). The financial analysis of Termoelectrica S.A. for 2020-2022 shows notable trends in revenue, costs, and profitability. Sales revenue grew significantly each year, indicating positive sales performance. However, the cost of sales also rose, particularly in 2022, which led to a decrease in gross and operating profits despite the initial increase in 2021. Financial income showed steady growth, while financial expenses varied, affecting net profit. For detailed financial indicators, see the figure below.



- Sales revenue and other operating income were: 117.6 million EUR in 2020, 157.3 million EUR in 2021, and 247.8 million EUR in 2022.
- Total costs and expenses reached 114.5 million EUR in 2020, 147.4 million EUR in 2021, and 260.4 million EUR in 2022.
- Operating results showed a loss of 3.1 million EUR in 2020, a profit of 1.8 million

Figure 4-1. Financial indicators (EUR)

EUR in 2021, and a loss of 46.8 thousand EUR in 2022.

The figure below illustrates the evolution of net profit (net loss) over the analysed period (EUR), providing a visual representation of its financial performance over time.

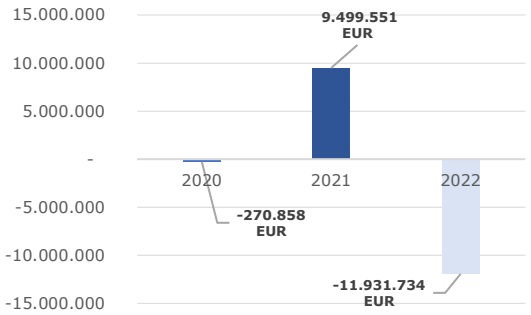


Figure 4-2. Evolution of net profit (net loss) for the period 2020-2022 (EUR)

- In 2020, Termoelectrica reported a net loss of 270,858 EUR, making it impossible to determine asset profitability for that year.
- In 2021, the Company achieved a net profit of 9,499,551 EUR, resulting in an asset profitability of 3.57%, which falls within the optimal range of 3% to 9%.
- By 2022, the Company faced another net loss, amounting to 11,931,734 EUR, which again prevented asset profitability calculation.

- The asset profitability calculation was based on net profit against total assets, with an ideal reference range set between 3% and 9%.

Analysis of asset inflows and outflows

Assets are the key resources Termoelectrica S.A. uses to operate and meet its goals. The asset structure and changes from January 1, 2021, to January 1, 2024, provide insight into resource allocation towards strategic objectives. Major asset categories include buildings, special constructions, machinery, equipment, transmission installations, data processing equipment, transportation, and tools. The composition of total assets as of January 1, 2024, is summarized in the figure below:

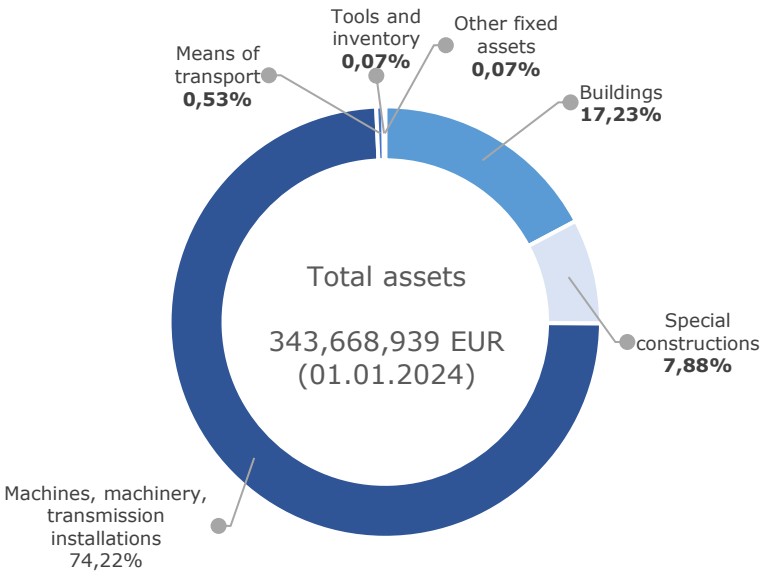


Figure 4-3. The composition of total assets as of January 1, 2024 (%)

- Machinery, equipment, and transmission installations form the largest share of the assets, maintaining high value across all periods.
- The asset growth during this interval reflects significant investments in infrastructure and equipment, aimed at boosting capacity and operational efficiency.
- Positive net cash flow and asset increase indicate effective financial management and enhanced revenue-generating potential.

Analysis of capital structure and debt

Analysis of the financing structure for the years 2020-2022 is presented in the table below:

Table 4-1. Analysis of the financing structure for the years 2020-2022

indicators	2020	2021	2022	Norm
Total debt to equity ratio	1.73	2.42	3.38	**0.5 - 1**
Equity ratio	0.37	0.29	0.23	**<0.5**
Long-term debt to equity ratio	1.64	2.03	2.38	**>1**
Current liabilities to equity ratio	0.10	0.38	1.00	**>1**

Source: Information from the financial statements of Termoelectrica S.A.

General conclusions:

- **Debt to equity ratio**: the ratio rose gradually from 1.73 in 2020 to 3.38 in 2022, showing an increased reliance on external financing, which signals higher financial risk.
- **Equity ratio**: the proportion of equity in the financing structure declined from 0.37 in 2020 to 0.23 in 2022, suggesting the company's reduced ability to fund activities using its own resources, making it more vulnerable to economic changes or unexpected events.
- **Long-term debt to equity**: this ratio increased from 1.64 in 2020 to 2.38 in 2022, indicating a heavier dependence on long-term debt to fund operations, potentially amplifying financial risk.
- **Current debt to equity**: the ratio of current debt to equity significantly rose in 2021 and reached 1.00 by 2022, up from only 0.10 in 2020. This rise highlights growing pressure on equity to cover current obligations, suggesting liquidity concerns.

The analysis reveals a trend of increased debt exposure for Termoelectrica S.A. and a reduced reliance on self-financing. While these highlights areas of financial vulnerability, it does not necessarily signify critical instability. With careful monitoring and strategic adjustments, the company can address these risks effectively. Proactive management and focused efforts to balance debt with equity can enhance financial resilience and support long-term sustainability.

4.2.2 Income Statement Analysis

The income statement analysis reviews the company's financial performance, focusing on revenue and expenses. Termoelectrica S.A. reported revenues of 119.2 million EUR in 2020, 160.5 million EUR in 2021, and 252.6 million EUR in 2022. The revenue structure and growth for 2020-2022 are shown in the table below:

Table 4-2. The structure and evolution of revenues for the period 2020-2022 (EUR)

Income Indicators	2020	2021	2022
Revenue - Total, including:	**119,179,808**	**160,515,566**	**252,610,742**
Sales revenue, of which:	**117,138,617** (98.3%)	**156,849,247** (97.7%)	**247,401,558** (97.9%)
Income from the sale of basic production (electricity, thermal energy)	112,507,626	147,979,768	239,734,261
Other operating income, (from lease, sale of unused assets, etc.)	4,630,991	8,869,479	1,180,762

Income Indicators	2020	2021	2022
Revenues related to means with special destination	0.0	0.0	6,486,535
Income from other activities	**2,125,396** (1.8%)	**3,666,319** (2.3%)	**5,209,184** (2.1%)
Income from long-term disposal of tangible assets	83,275	314,315	370,796
Income from exchange rate differences	1,451,547	3,309,423	4,318,484
Income in the form of dividends	381,588	0.0	469,201
Income from immobilized and current assets entered free of charge	97,067	0.0	0.0
Other exceptional income	83,066	1,502	10,812
Other operating income (in the form of interest, difference in amount)	28,853	41,079	39,890

Source: Data provided by Termoelectrica S.A.

General conclusions:

- **Core revenue source**: the main revenue for Termoelectrica S.A. is from electricity and heat trading.
- **Revenue breakdown**: in 2020, 94.4% (112.5 million EUR) came from core activities; in 2021, it was 92.2% (148.0 million EUR); and in 2022, it rose to 94.9% (239.7 million EUR).
- **Additional income sources**: the company also earned from asset sales, exchange rate gains, and leasing properties.
- **Other income growth**: other income grew steadily - 1.8% in 2020 (2.1 million EUR), 2.3% in 2021 (3.7 million EUR), and 2.1% in 2022 (5.2 million EUR).
- **Significant revenue increase**: revenue increased by 41.3 million EUR in 2021 from 2020 and by 92.1 million EUR in 2022 from 2021.
- **Reason for growth**: the revenue rise was largely due to higher tariffs for heat and electricity, reflecting strong market adaptation.

Termoelectrica S.A. provided data on total amounts billed from 2020 to 2023, and the analysis was based solely on these receipts. The evolution of total receipts for 2020-2023 (EUR) is shown below:

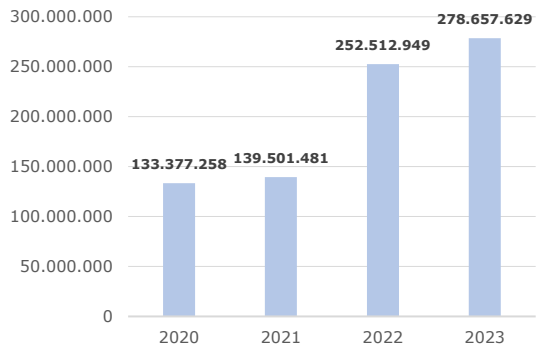


Figure 4-4. Evolution of total receipts for the years 2020-2023 (EUR)

- **Primary revenue source**: the company's main cash flow stems from the production and supply of thermal and electric energy through commercial partnerships and public contracts.
- **Income stability and diversification**: stability in core revenue streams with additional income from government contracts and asset rentals, diversifying income sources.
- **Growth in long-term receivables**: notable increase in long-term receivables observed in 2022, adding potential future income.

- **Cash flow changes**: Overall cash flow in 2023 reflects growth and significant changes from previous years.

Source: Data provided by Termoelectrica S.A.

The cash flow analysis from 2020 to 2023 demonstrates stable growth and diversification in revenue sources, indicating an overall improvement in the company's financial performance. However, to ensure long-term stability, Termoelectrica S.A. must continue to apply effective risk management strategies and enhance operational efficiency to strengthen its market position and sustain growth.

4.2.3 Cash Flow Statement Analysis

Cash flow for Termoelectrica S.A. is generated from three main activities: operational, investment, and financial. To maintain financial stability, the company must ensure that receipts exceed payments, covering all operational, financial, and investment needs. A positive balance indicates financial health, while a negative balance suggests a resource deficit requiring urgent attention. Achieving perfect synchronization between inflows and outflows is rare, as cash flow is continuously in motion.

The **cash flow analysis** for the period 2020-2022 (EUR) is shown below:

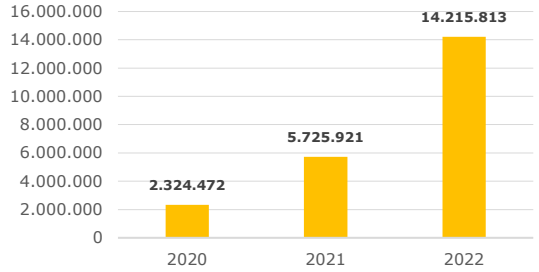


Figure 4-5. Cash flow analysis for the period 2020-2022 (EUR)

- **Operating activities**: the net cash flow was negative in 2020 (-4,788,702 EUR) but turned positive in 2021 (13,897,727 EUR) and 2022 (9,847,296 EUR), indicating improved receipts over payments.
- **Investing activities**: negative cash flows in 2020 and 2021, at -11,304,331 EUR and -8,792,053 EUR, due to significant spending on fixed asset acquisitions.
- **Financing activities**: loan repayments were made each year, totalling 1,168,782 EUR in 2020, 1,673,432 EUR in 2021, and 1,388,633 EUR in 2022, with additional interest costs due to challenging financial conditions.
- **Total cash balance**: the cash balance grew steadily, reaching 2,324,472 EUR in 2020, 5,725,921 EUR in 2021, and 14,215,813 EUR in 2022, reflecting substantial increases of 148.3% from 2020 to 2021 and 511.6% from 2020 to 2022.

Source: information from the financial statements of Termoelectrica S.A.

Termoelectrica S.A.'s development relies on maintaining financial balance, which aligns the need for financial resources with the ability to secure them. Working capital serves as a key measure, setting the foundation for balance and enterprise autonomy. Liquidity, or the company's ability to convert assets into cash, reflects its payment capacity. Liquidity indicators are shown in the table below:

Table 4-3. Presentation of liquidity indicators

Indicator	2020	2021	2022	Norm
Immediate liquidity ratio	0.23	0.19	0.22	**0.2-0.3**

Relative liquidity ratio	1.99	1.97	1.18	**<1**
Current liquidity ratio	6.77	2.42	1.57	**1.2-1.8**

General conclusions:

- **Immediate liquidity ratio**: Termoelectrica's ratio from 2020-2022 is within the acceptable range (0.2-0.3), indicating adequate receivables convertible to cash as needed.
- **Relative liquidity ratio**: the ratio is above the permissible limit, ensuring sufficient cash availability (around 1 of total assets) to meet immediate payments and prevent financial issues like insolvency.
- **Current liquidity ratio**: ideally above 1, a range of 1.2-1.8 reflects a stable financial position. However, there is a noted decrease in 2022 compared to 2020, suggesting a potential reduction in the ability to meet short-term obligations.

The cash flow analysis shows a strong revenue increase, though careful expense management is essential to maintain long-term financial stability amidst rising operational costs. The consistent growth in the cash balance reflects an improved financial position, enabling the Company to meet debts, invest in development, and repay creditors. While Termoelectrica S.A. has enough liquidity to meet immediate obligations, sustained long-term success requires more than liquidity alone.

4.3 Preliminary financial projections, 2024-2030

The financial projections for Termoelectrica S.A. are based on critical assumptions regarding currency exchange rates, energy prices, tariffs, and volumes of heat and electricity produced.

PROFIT AND LOSS FORECAST

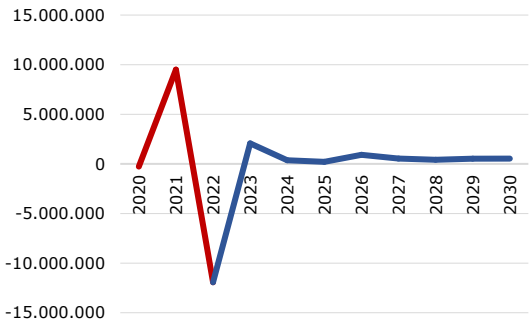


Figure 4-6. Profit and Loss forecast, 2024-2030 (EUR)

CASH FLOW FORECAST

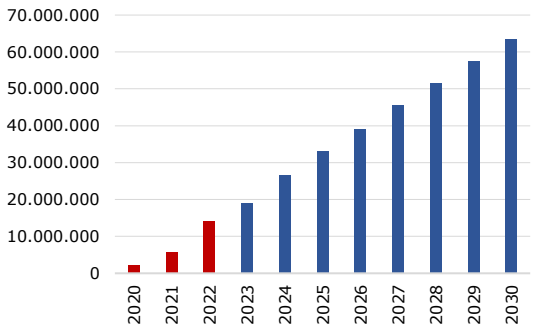


Figure 4-7. Cash flow forecast, 2024-2030 (EUR)

- It should be noted that in 2023, the highest values for both Revenue from Sales and Cost of Sales were recorded for the entire analyzed period. This was due to the peak increase in the price of electricity produced and the tariff for thermal energy delivered to consumers, which in turn was driven by the rising cost of natural gas.
- In 2030, the expected Revenue from sales is projected to be 236,036,552 EUR, while
- The Net cash flow from operating activities in 2030 is expected to be 7,455,099 EUR, while the Net cash flow from financial activities is projected to be -1,514,118 EUR. As a result, the Total net cash flow is anticipated to be 5,940,981 EUR.
- Over the 11-year period from 2020 to 2030, considering the forecast, the Cash

the Cost of sales is anticipated to be 233,443,443 EUR. As a result, the Gross profit will amount to 2,593,109 EUR.

- A profit from exploitation is expected to be 542,999 EUR for 2030. Additionally, the Profit from other operating activities is projected to be 53,913 EUR, and the Profit from non-current asset operations is estimated to be 52,065 EUR.
- The Net profit of the management period in 2030 is expected to be 532,487 EUR. As a result, the profitability of sales cannot be determined due to the Company's losses.

balance at the beginning of the management period in 2030 is expected to be 57,600,335 EUR. By the end of the management period, the Cash balance is projected to be 63,541,316 EUR.

As a result of the cash flow analysis, we can conclude that the years 2022 and 2023 can be considered favourable in terms of receipts for Termoelectrica S.A., reflecting success in its operations and its ability to adapt and thrive in a continuously changing economic environment. The subsequent forecast for 2024-2030 indicates the company's ability to meet the necessary obligations in the implementation of the current project.

5. Energy Model

In order to assess the feasibility of various alternative energy sources for Chisinau, Republic of Moldova, an energy model was developed. This model facilitates the calculation of comprehensive energy balances, which will serve as the foundation for future cost balance calculations. The model is designed to evaluate each proposed alternative energy source in the context of Chisinau's specific energy demands and geographic characteristics. This will allow for the identification of the most suitable option for detailed analysis, ensuring an optimized and data-driven approach to energy production in Chisinau.

5.1 Structure of the Energy Model

The structure of the model is pre-defined in the "Request for Proposals" document (file: RFP_no 9134-B1.6_05.05.2023-as issued-Colenco-Ekonerg.pdf).

As illustrated in the referenced image (Figure 5-1), the input data predominantly comprises several critical elements:

- district heating demand curves (both current and projected),
- capacity performance metrics for existing and future production units, and
- characteristics of available fuels, such as natural gas and RDF[30].

The district heating demand curves provide insight into both present and future heating requirements, allowing for precise planning and adjustment of production capacities. The capacity performance metrics of production units, including both current and anticipated installations, offer vital data on operational efficiency and potential output. The fuel characteristics, detailing properties of natural gas and RDF, enable accurate calculations of fuel consumption and emissions.

The model's output primarily consists of several key projections and estimates. These include the anticipated heat and electricity generation from both new and existing units, offering a clear picture of future energy production capabilities. Additionally, the model provides detailed estimates of fuel consumption, which are crucial for budgeting and resource planning. Lastly, CO2 emission forecasts are included to assess the environmental impact and ensure compliance with regulatory standards.

Overall, this structured approach ensures a robust and reliable model, capable of supporting informed decision-making and strategic planning for future district heating and energy production needs.

This model facilitates energy analysis across various configurations of the energy system, based on selected production units and input data. It generates results that include heat production, electrical energy (EE) production and consumption, fuel consumption, CO_2 emissions, and overall annual efficiency for the evaluated CHP units.

[30] RDF - Refuse Derived Fuel (fuel from waste)

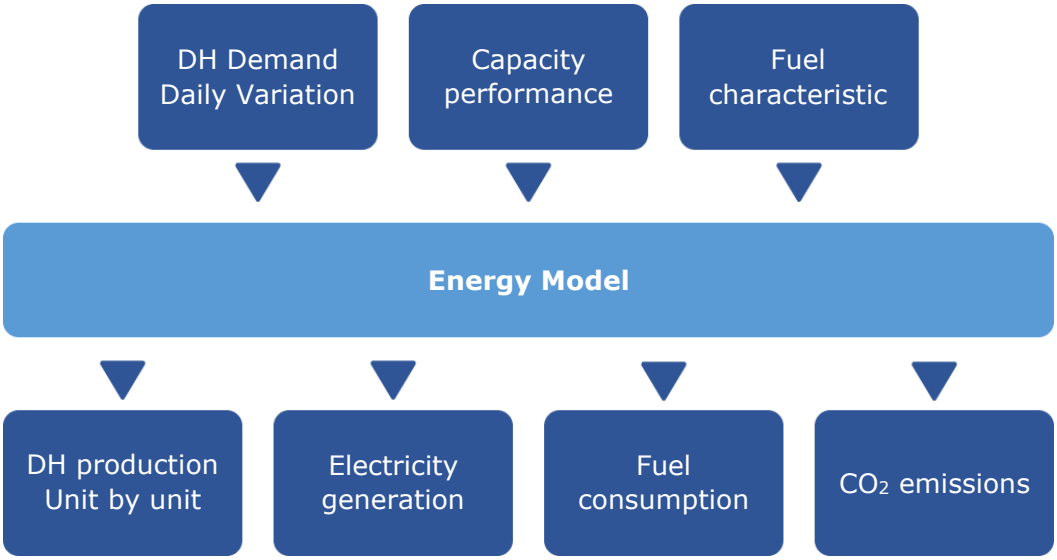


Figure 5-1. Structure of the Energy model

5.1.1 Short Description of the Functionality

5.1.1.1 District Heating Demand Curve

The Energy Model, developed in Microsoft Excel, enables projections of future unit engagement based on predefined District Heating (DH) demand curves spanning the next 23 years (see chapter 5.1.2).

Users can enhance analysis by creating combined demand curves, selecting multiple network curves, such as integrating the "Source 1/2/3" demand curve with the "HOB-W" demand curve. Additionally, the model accommodates the inclusion of the "Domestic Hot Water" demand curve, allowing for a more comprehensive demand assessment.

For targeted analysis, the model also supports isolated examination of specific networks, such as focusing exclusively on "HOB-South."

Beyond the predefined DH demand curves, the application provides the flexibility to implement a custom DH demand curve defined directly by the user. This feature empowers users to specify unique data points, allowing for precise customization and control over the DH demand curve to meet individual analytical requirements.

In addition to the previously mentioned features, users have the option to adjust the overall District Heating (DH) demand by specifying a percentage change. For example, if a user inputs 5%, the total DH demand will increase by 5%. Conversely, entering a negative value, such as -5%, will decrease the overall demand by the specified percentage.

This functionality allows users to apply precise adjustments to the existing DH demand curve, offering greater flexibility in fine-tuning demand projections.

5.1.1.2 Network configuration

Additionally, the user is allowed to define a DH network configuration by choosing from multiple combinations of existing DH networks in the city of Chisinau. Specifically, the user can create a

combined network by selecting multiple networks. For example, the user can combine the "Source 1/2/3" network with the "HOB-W" network. Users also have the option to analyse "Source 1/2/3" network separately if preferred.

5.1.1.3 Solar Heating and corrected DH demand curve

When users choose to include Solar Heating in the analysis of overall heat demand coverage, the application enables them to visualize the transformative impact of solar thermal integration on the district heating (DH) system's demand curve. The model specifically illustrates how solar heat energy offsets the baseline DH demand, creating a new demand profile characterized by additional fluctuations and intermittency.

Given that solar energy production is inherently variable – affected by factors such as weather conditions, cloud cover, and temperature fluctuations – the adjusted demand curve captures this variability, often showing more frequent changes throughout the day. This updated heat demand curve then becomes the basis for all subsequent calculations and analysis, reflecting the dynamics introduced by solar integration.

5.1.1.4 Thermal Energy Storage (TES)

Similar to Solar Heating, users can integrate Thermal Energy Storage (TES) into the model to mitigate daily heat demand fluctuations and intermittency. To incorporate TES, users simply need to define the Maximum Thermal Storage Capacity (the upper limit of usable heat energy the system can store) and the Maximum Power Output/Input (the rate at which heat energy can be added to or withdrawn from the storage).

The integration of TES has a substantial impact on flattening the demand curve, effectively smoothing out fluctuations without affecting the total heat delivered. The application also visualizes this process by displaying the interaction between the initial heat demand curve and the new, flattened curve. It is important to note that the areas under both curves (original and TES-flattened) remain approximately equal, as TES neither generates nor consumes energy.

The methodology for creating the adjusted demand curve utilizes a moving average approach, enhanced with correction procedures that account for TES capacity and current energy storage levels, ensuring accurate modelling of TES dynamics.

5.1.1.5 Fuel

The model allows for defining fuel characteristics (specifically, Lower Heating Value (LHV) and CO_2 Emission Coefficient) for natural gas through two possible approaches:

- Direct Input: This straightforward method allows users to directly input known values of LHV and CO_2 Emission Coefficient for their specific natural gas source, enabling quick and efficient utilization of readily available data.
- Composition-Based Approach: If exact LHV and CO_2 Emission Coefficient values are unavailable, the model supports a more flexible, composition-based approach. Users can enter the specific percentages of gas components (e.g., methane, ethane, propane) to enable the model to calculate the LHV and CO_2 Emission Coefficient for a given gas sample. This approach is particularly useful for handling varied gas sources with unknown properties.

For Waste-to-Energy (WtE) fuel units, the model requires the user to define the LHV due to the unpredictable nature of Refuse-Derived Fuel (RDF). Additionally, the CO_2 emission coefficient must be specified directly, as Refuse-Derived Fuel (RDF) contains fossil carbon. To ensure accurate CO_2

emission calculations for the fossil component, users also need to specify the percentage of fossil carbon present in the RDF. This provision allows the model to accurately assess emissions associated with the fossil-derived component in waste.

5.1.1.6 Energy prices

Electricity and heat prices are incorporated into the model to identify hours within the year when the selling price of heat surpasses that of electricity. During these periods, it becomes advantageous to operate electric hot water boilers for heat production, provided such boilers are part of the heat production mix. As a result, these electric hot water boilers will only be operational during these specified hours, optimizing production costs.

For further details on the methodology used to define future price projections, please refer to chapter 7.2.2.1.

5.1.1.7 Industry sector

The Energy Model enables users to define projected heat contributions from the industrial sector in Chisinau. Given the uncertainty surrounding future contributions from these third-party sources, the model adopts a simplified approach, allowing users to simply input estimated industrial heat production values directly, without requiring additional analysis. These values are then subtracted directly from the heat demand curve, thereby lowering the demand that existing and new production units need to meet.

Additionally, the model allows users to designate whether the heat produced by various industrial sources should be prioritized over that from new energy sources planned at the Source 1 location. This prioritization feature supports flexible and efficient integration of industrial heat input.

Upon defining District heating demand curve, as well as TES and contribution from industrial sector, the energy model allows users to define heat production mix. In another words, the user is prompted to choose new units that will be analysed as part of future production mix as well as to define which of existing production units will still be operational in the specified year of analysis.

For each unit, regardless of its type, the user is allowed to define a dedicated maintenance period by specify the starting date and the duration of a maintenance period (in days). For defined periods the units will not be available.

5.1.1.8 Mode of Operation

The model enables users to choose between two operational strategies:

- ***Maximum Electricity Generation:*** In this mode, the model prioritizes achieving the highest possible electrical output while ensuring that heat demand is fully met.
- ***Minimum Electricity Generation:*** Alternatively, this mode emphasizes heat production, with the system operating at the lowest electricity output level necessary to satisfy heat requirements.

These two distinct modes of operation provide flexibility to accommodate varying operational strategies and objectives, allowing the system to be optimized according to specific performance requirements.

5.1.1.9 Unit scheduling priority

Unit scheduling follows a predefined priority order based on specific criteria:

- Renewable energy units are prioritized over gas-fired units.

- Newly commissioned units are given priority over existing ones.
- Combined Heat and Power (CHP) units have priority over simple boiler systems.
- For industrial sources, a priority can be assigned by the user. Specifically, the model allows users to determine whether heat energy from industrial sources should take precedence over renewable units. However, heat from industrial sources always takes priority over gas-fired units and existing units.

5.1.1.10 Specific production unit modelling

All new and existing production units within the Energy Model are configured using a tailored set of equation of varying complexity.

For existing units, data provided by Termoelectrica served as the foundation. These data were first used to develop a standalone model in MS Excel, functioning as a proof of concept. Each unit was modelled independently, facilitating easy refinement of calculations and ensuring accuracy. Once the model demonstrated acceptable results, it was seamlessly integrated into the main model. This step-by-step approach enabled the creation of a robust and reliable application that accurately reflects real-world performance.

For new units, particularly complex ones like Combined Heat and Power (CHP) units, EBSILON power plant modelling software was utilized. Similar to the process for existing units, an initial model was developed in Excel to formulate the appropriate polynomial expressions, though this time, data from the EBSILON model was employed. Upon completion, this model was incorporated into the main model following the same integration process used for existing units. This systematic approach ensures both accuracy and consistency across all unit types within the model.

5.1.2 Heat Energy Demand of Chisinau

5.1.2.1 Introduction

Purpose

The following section presents an analysis of Termoelectrica's consumer demand for DH in Chisinau, specifically for heating and hot water consumption. To forecast future demand, a set of assumptions was applied for the assessment of various influencing factors. These assumptions were critical for creating a realistic model.

The baseline consumption was based on actual heat consumption data from 2021. This year was selected because it was the last period during which heating services were provided without restrictions according to actual demand. In subsequent years, the heating supply faced limitations due to fuel availability and other significant factors (related to the energy crisis), which distorted the true picture of demand.

Relevance of the Time Period

In forecasting future demand, changes in the DH system and consumer behaviour that occurred during the period from 2021 to 2024 were taken into account, including the results from the implementation of energy-efficiency measures.

The demand forecast has been calculated through to the year 2050. While the core implementation period for the project has been set between 2027 and 2037, the forecast begins in 2027 to allow sufficient time for preparatory works, tendering, and other necessary steps required for the development of new generation facilities. The 10-year assessment period was selected to capture

the impact of additional energy-saving measures planned in the city under other projects. However, the forecast was extended to 2050 to account for potential delays, adjustments in project timelines, and to provide a robust data range for modelling various future scenarios.

5.1.2.2 Methodology

5.1.2.2.1 Base Load Calculation

Consumers of centralized heat energy supply for heating in Chisinau are distributed across 5 districts. The majority are connected to CHP Source-1 / Source-2, which supplies all five districts, whereas the heat-only boiler plants each serve only some parts of the DH system in winter: HOB-West covers the Buiucani district (complementing the heat supplied from CHP Source-1 / Source-2), and HOB-South serves an area in south-west part of the city ("Telecentru area). The total number of centralized heat energy consumers for heating in 2021 amounted to 9,302 (including apartment-level consumers in some buildings with horizontal distribution).

Table 5-1. Heat consumers for heating in Chisinau, 2021

Source	Ciocana	Centru	Riscani	Botanica	Buiucani	Total
CHP Source-1 / Source-2	1,571	1,667	2,344	1,490	263	**7,335**
HOB-West	-	-	-	-	1,335	**1,335**
HOB-South	-	632	-	-	-	**632**
Total	**1,571**	**2,299**	**2,344**	**1,490**	**1,598**	**9,302**

Source: Termoelectrica S.A.

In 2021, the number of consumers of centralized heat supply for hot water in the city was nearly half that of consumers for centralized heating (5,125). Although during the summer season, heat for DHW preparation is supplied through a unified DH circuit to all city consumers, the distribution of consumers by their connection to each respective source/area is shown below:

Table 5-2. Heat consumers for DHW in Chisinau, 2021

Source	Ciocana	Centru	Riscani	Botanica	Buiucani	Total
CHP Source-1 / Source-2	968	1,183	1,270	680	78	**4,179**
HOB-West	-	-	-	-	651	**651**
HOB-South	-	295	-	-	-	**295**
Total	**968**	**1,478**	**1,270**	**680**	**729**	**5,125**

Source: Termoelectrica S.A.

The table below provides an overview of heat consumption for heating and DHW among Chisinau consumers in 2021 (MWh). It shows monthly consumption patterns, highlighting the higher demand for heating during colder months and the relatively stable demand for hot water supply throughout the year. This data enables a detailed analysis of seasonal variations in heat energy usage across the city.

Overall, the total heat consumption in 2021 amounted to 1,350,931 MWh for heating and 217,324 MWh for DHW, illustrating the significantly higher energy demand for heating compared to hot water services.

In total, the combined heat consumption for both heating and DHW in Chisinau for 2021 reached 1,568,255 MWh.

Table 5-3. Heat consumption for heating and hot water supply of Chisinau consumers in 2021 (MWh)

Month	Heating	DHW	Total
January	269,100	22,033	**291,133**
February	279,961	22,424	**302,385**
March	236,053	21,622	**257,675**
April	110,098	19,975	**130,072**
May	-	19,619	**19,619**
June	-	15,594	**15,594**
July	-	12,642	**12,642**
August	-	11,040	**11,040**
September	-	15,386	**15,386**
October	17,586	17,134	**34,720**
November	189,888	19,942	**209,830**
December	248,247	19,913	**268,160**
Total	**1,350,931**	**217,324**	**1,568,255**

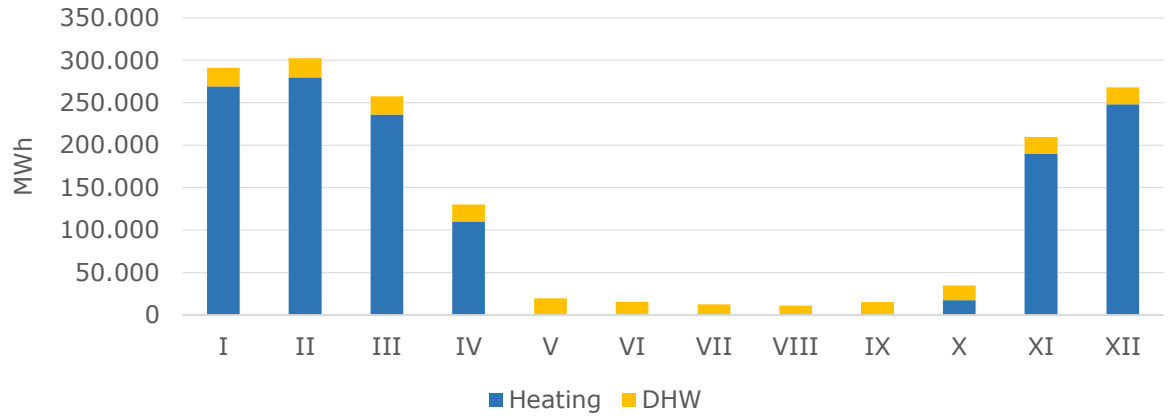


Figure 5-2. Heat consumption for heating and hot water supply of Chisinau consumers in 2021

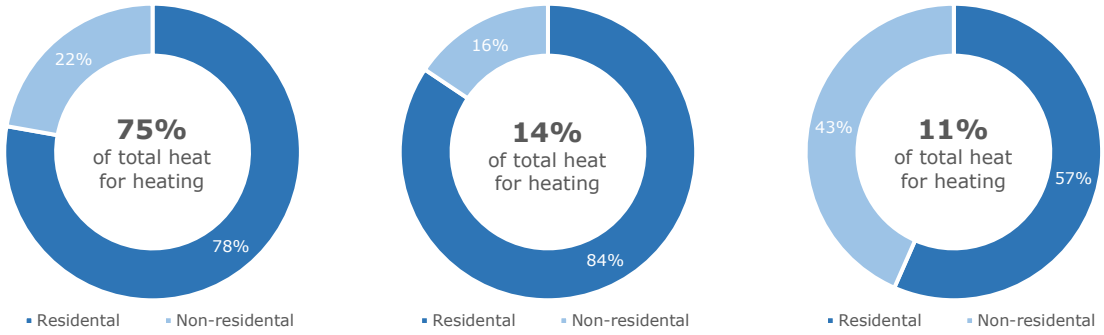
The distribution of heat consumers for heating and hot water supply, broken down by consumer type (residential or non-residential), is shown below:

CHP SOURCE-1/SOURCE-2	HOB-WEST	HOB-SOUTH
Heating		
The distribution of heat consumers in Chisinau indicates that the majority are connected to CHP Source-1 / Source-2, accounting for 7,335 consumers, or approximately 79% of the total. Residential consumers form a significant part of the overall demand, with 7,043 residential connections compared to 2,259 non-residential connections. Specifically, HOB-West serves 1,335 consumers (around 14% of the total), while CHP-South has 632 consumers, representing roughly		

7%. This breakdown highlights the predominance of residential consumers in the city's main centralized heating network, with Source-1 serving the largest share of both residential and non-residential users.

To be noted that in winter CHP Source-1 / Source-2 DH circuit and HOB-West DH circuit are interconnected, and a part of the heat in HOB-West DH circuit is supplied from CHP Source-1 / Source-2 (complemented by heat from HOB-West), while HOB-South circuit operates independently (supplied from HOB-South). During the summer CHP Source-1 / Source-2, HOB-West and HOB-South DH circuits are interconnected.

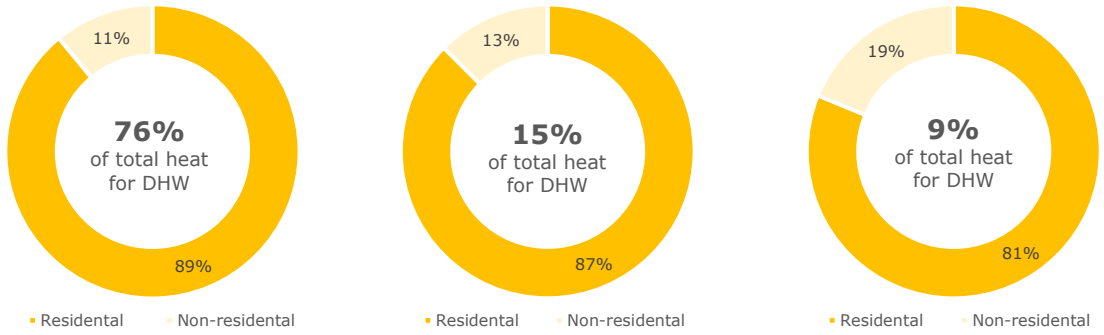
The distribution of consumers by heat consumption level for heating is shown below:



DHW

The distribution of DHW consumers in Chisinau indicates their connections to specific sources, though in summer hot water is supplied through a single unified DH network. CHP Source-1 / Source-2 has the highest number of connected consumers, with 4,179 connections, representing approximately 82% of the total. Of these, residential consumers account for 3,787 connections (around 90.6%), while non-residential consumers represent 392 connections (about 9.4%). Additional connections include 651 consumers (12.7% of the total) linked to HOB-West and 295 consumers (5.8% of the total) linked to HOB-South.

The distribution of consumers by DHW consumption level is shown below:



Based on the 2021 heat consumption data of Chisinau consumers, a baseline load for the DH system was calculated. To enhance the accuracy of this assessment, the load distribution across different sources was considered, allowing for a more detailed analysis of each source's contribution.

The overall peak load for DH consumers connected to the DH system was calculated at **737.25 MW**, broken down as follows:

- **CHP Source-1 / Source-2**: 547.24 MW

- **HOB-West**: 106.96 MW
- **HOB-South**: 83.05 MW

This detailed distribution helps identify the load carried by each source within the DH system, providing valuable insights into system performance and the specific demands placed on each source.

For DHW consumers, the peak load reached **64.10 MW**, reflecting the relatively lower demand for hot water compared to heating. This data-driven approach to baseline load calculation provides a solid foundation for future demand forecasting and infrastructure planning.

5.1.2.2.2 Historical Adjustments

To begin forecasting consumption for the future period, it was necessary to take into account the impact of historical changes that occurred within the city's DH system, as well as among its consumers, during the period leading up to the commencement of this study, specifically from 2021 to 2024.



Impact of implemented IHSs during 2021-2024

Reduction in heat demand for heating due to the installation of IHS during the period 2021-2024 up to forecasting and, accordingly, an increase in DHW demand

Between 2021 and 2024 (from the baseline year to the period of analysis), approximately 200 IHS were installed across the city. This initiative has positively impacted overall heat consumption by reducing demand for heating while simultaneously increasing the consumption of centralised DHW. The increase in DHW demand is attributed both to the connection of new consumers who previously lacked access to centralised hot water and to the enhanced quality of service resulting from these upgrades.

The estimated effect of this measure on baseline demand is as follows:

- **Reduction in heating demand**: an annual decrease in heating demand by approximately 0.70%, driven by improved efficiency due to IHS installations;
- **Increase in DHW demand**: an annual increase in DHW demand of around 0.14%, reflecting the additional consumption from newly connected users and an uplift in service quality.

Overall, the installation of IHS has contributed to both energy savings in heating and expanded access to reliable hot water services, supporting the city's goals of energy efficiency and improved quality of life for residents.

The positive impact serves as an effective catalyst for scaling these measures. The city is now considering long-term initiatives focused on the widespread installation of IHS and transitioning buildings from vertical to horizontal distribution networks. These efforts are expected to yield significant energy savings, enhance service quality, and provide greater control over individual consumption, contributing to a more efficient and resilient heating infrastructure across Chisinau.



Annual disconnection and connection of consumers during 2021-2024

Change in heat demand for heating and DHW due to the natural change in consumers during the period 2021-2024 up to forecasting

The analysis of heat consumption for heating and hot water supply for the years 2021 and 2024 showed that during this period, some users who had utilized DH services in 2021 were no longer

consuming heat in 2024. The percentage of disconnected consumers amounted to 2.58% for heating (74 residential consumers and 166 non-residential consumers) and 6.75% for hot water supply (284 residential consumers and 62 non-residential consumers). However, even taking into account the disconnected consumers by 2024, the overall number of heating consumers increased by 25% (1208 residential and 1,098 non-residential consumers), and the number of hot water consumers grew by 9% (389 residential and 54 non-residential consumers).

The growth rate in the number of consumers does not directly correlate with changes in consumption volume due to several factors:

- Consumers range from individual residents in apartment buildings with horizontal pipeline distribution and individual metering, to public buildings such as schools or hospitals, where consumption levels vary significantly.
- A significant part of the increase in consumer numbers is due to the transition of MFB from vertical to horizontal distribution. This shift allowed all residents in a building to switch to individual metering, effectively increasing the number of consumers from one per building to several dozen, depending on the number of apartments.
- Similarly, where a disconnected consumer may have previously consumed a substantial amount of heat, new consumers often have much lower consumption needs.

Therefore, despite the considerable increase in the number of consumers, the overall connected load to the centralized heating system turned out to be relatively insignificant. The results of the annual impact on the baseline load are presented below:

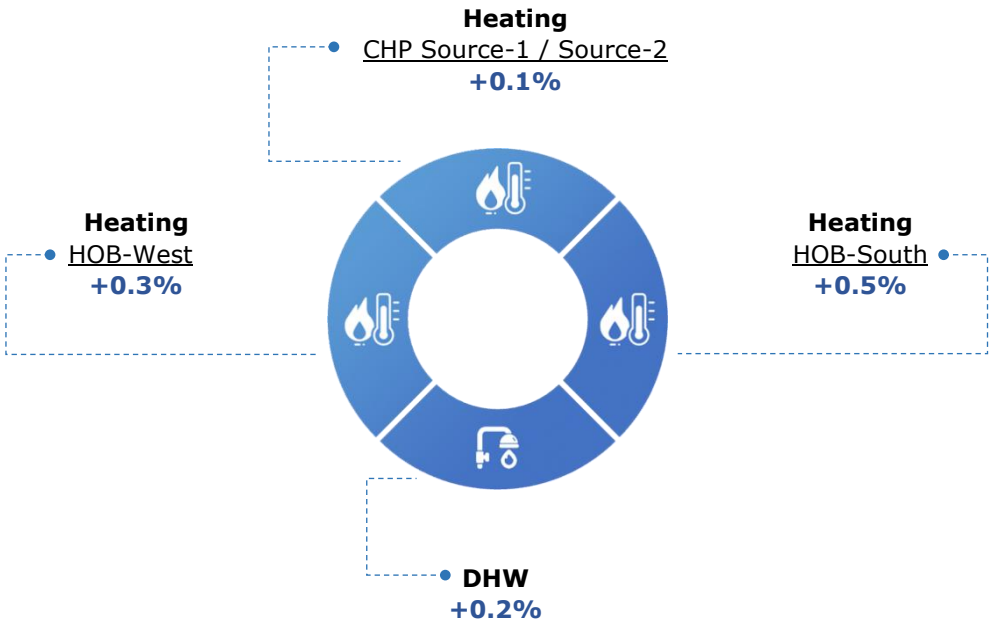


Figure 5-3. Annual increase in baseline DH load for the period 2021-2024

5.1.2.2.3 Assumption

Energy-efficiency measures: installation of IHS and horizontal heating systems

Reduction in heat demand for heating and increase in DHW consumers

Termoelectrica is actively implementing the installation of individual heat substations (IHS) and transitioning MFBs from vertical to horizontal distribution systems.

According to the *Termoelectrica Chisinau District Heating Project (EBRD)*, the city plans to implement these measures with the following scope and estimated savings:

- **2,090 buildings**: installation of IHS and horizontal networks, projected to achieve savings of approximately 23%;
- **1,149 buildings**: installation of IHS only, with an estimated savings of 8%;
- **499 buildings**: installation of horizontal networks where IHS have already been installed, with projected savings of 15%.

Table 5-4. Advantages of installing IHS and switching to horizontal distribution in MFBs

Installation of IHS	Transition to horizontal distribution
▪ Enables more precise control over heating and hot water supply, allowing consumers to adjust their energy use based on individual needs, which improves overall comfort and efficiency. ▪ Reduces energy losses within the building, leading to lower heating costs and optimised energy consumption, contributing to a more sustainable and cost-effective heating system.	▪ Provides individual metering for each apartment, allowing residents to monitor and manage their consumption independently, leading to fairer billing practices and increased motivation for energy-saving behaviour. ▪ Enhances maintenance flexibility and system reliability, as horizontal networks are easier to isolate and repair without affecting other units, resulting in improved service continuity. ▪ Enables reconnection of consumers to DHW supply in buildings which currently do not use DHW supply services (together with installation of IHS). ▪ Enables reconnection of disconnected apartments that currently use individual gas boilers.

The implementation of these measures is expected to result in a significant reduction in heating demand for space heating, segmented by the source to which consumers are connected, as follows:

CHP Source-1/Source-2	HOB-West	HOB-South
-14.0%	-10.7%	-12.2%

This comprehensive set of measures aims to modernise the heating infrastructure, reduce energy waste, and significantly improve efficiency and service quality. By implementing IHS and horizontal distribution, Termoelectrica can create a more sustainable DH network that is better equipped to meet the needs of its consumers.

Besides, other energy efficiency measures will be implemented in buildings in Chisinau.

Impact on increasing DHW consumers

The implementation of these measures is expected to positively influence the consumption of centralised hot water supply. The impact on DHW consumers can be categorised into the following areas:

- **Buildings with existing DHW access**: in buildings that already have access to centralised DHW, the installation of IHS and the transition to horizontal distribution is expected to result in a slight increase in DHW consumption due to the improved quality of heat preparation and supply, leading to greater user satisfaction.

- **Buildings without existing DHW access**: for buildings currently lacking centralised DHW, the proposed measures will enable full connection of new consumers to the DHW services, expanding service availability and customer base.

As a result, the expected increase in hot water consumption due to the implementation of these measures is estimated to be approximately 22%.

Potential connection of new consumers

Increase in heat demand for heating and DHW due to the connection of new consumers (residential complexes)

One of the factors driving increased demand for thermal energy consumption is the connection of new consumers to the DH network. These can include both new residential complexes and consumers with individual heating systems, such as buildings which currently use rooftop boiler houses. According to Termoelectrica's information, discussions are currently underway regarding the potential connection of 6 such consumers to the CHP Source-1 / Source-2 and 1 consumer to the HOB-West. Detailed information on the projected capacity is provided in the table below:

Table 5-5. Potential new consumers for connection to Chisinau's DH system

No.	Name and location	Description	Projected thermal load for heating, MW	Projected thermal load for DHW, MW	Connection Details
1	"LAGMAR IMPEX" – "CLUJ" neighborhood, Poșta Veche St.	Area: approx. 484,000 m², approx. 6,600 apartments	4.000	4.000	CHP Source-1 / Source-2
2	"UNICAL-CONSTRUCT" – Calea Orheiului St.	Residential complex with 5 blocks, commercial spaces, underground parking	4.450	1.750	CHP Source-1 / Source-2
3	"HORUS-CONSTRUCTION" – Tudor Vladimirescu St., 1/8	Residential complex with 38 buildings	18.600	10.600	CHP Source-1 / Source-2
4	"KIRSAN" S.R.L. – Dacia Blvd., "METROPOLIS" complex	Negotiations for DH connection, construction halted	7.000	6.160	CHP Source-1 / Source-2
5	Residential Building – Ștefan Neaga St., 74	Rooftop boiler house	0.320	0.240	HOB-West
6	Residential Building – Zelinski St., 15/2, 15/3, 15/4	Rooftop boiler house	0.581	0.697	CHP Source-1 / Source-2
7	Residential Building – Liviu Rebreanu Deleanu St., 10	Individual heating	0.074	0.093	CHP Source-1 / Source-2
	Total		**35.025**	**23.54**	

Source: Termoelectrica S.A.

The total projected capacity for the mentioned potential new consumers amounts to 35.025 MW for heating and 23.54 MW for DHW. An analysis by the consultant of the actual hot water consumption situation in the city, along with general trends, shows that the projected capacity for DHW is often overestimated due to outdated calculation standards that do not reflect the current situation. Consequently, the hot water capacity was recalculated, resulting in a revised figure of 3.68 MW.

Besides residential consumers, it is expected that Termoelectrica will continue to reconnect/connect public buildings, and attract other categories of consumers to connect to DH. Recently Termoelectrica has connected new office and commercial buildings, and other buildings are planned to be connected.

The connection of new consumers is expected to drive demand growth for heating for those connected to CHP Source-1 / Source-2 by 2.86% annually over three years from 2025 to 2027, and for consumers connected to HOB-West by 0.4% overall. Meanwhile, the demand growth for DHW is expected to be 2.14% annually over the same three-year period.

Population growth

Historical trend of changes in the number of residents, which potentially affects the growth in heat demand

One of the natural drivers of demand growth is the historical increase in population, accompanied by the construction of new residential and public buildings to serve this population. According to the National Bureau of Statistics of the Republic of Moldova, over the past five years, from 2019 to 2023, Chisinau has experienced consistent population growth. The highest increase was observed in 2021 compared to 2020, with a growth rate of 1.2%. Detailed information on the population dynamics in Chisinau over recent years is presented in the diagrams below:

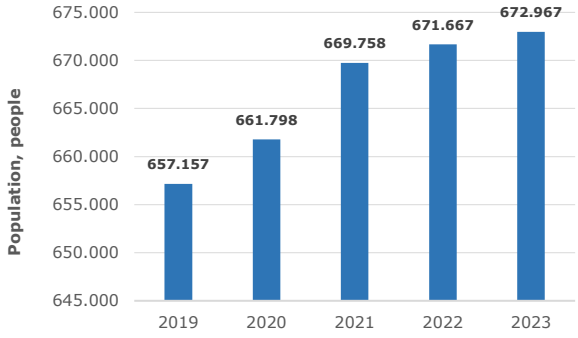


Figure 5-4. Historical data on the population in Chisinau, 2019-2023

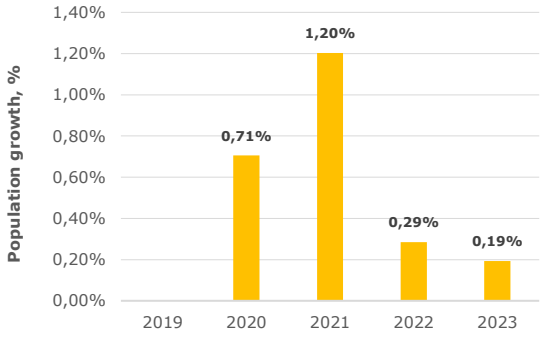


Figure 5-5. Population growth in Chisinau, 2019-2023

Source: National Bureau of Statistics of the Republic of Moldova

On average, the population growth rate over the past five years was approximately 0.6%. The diagram below presents a forecast of population growth up to 2050, taking historical trends into account.

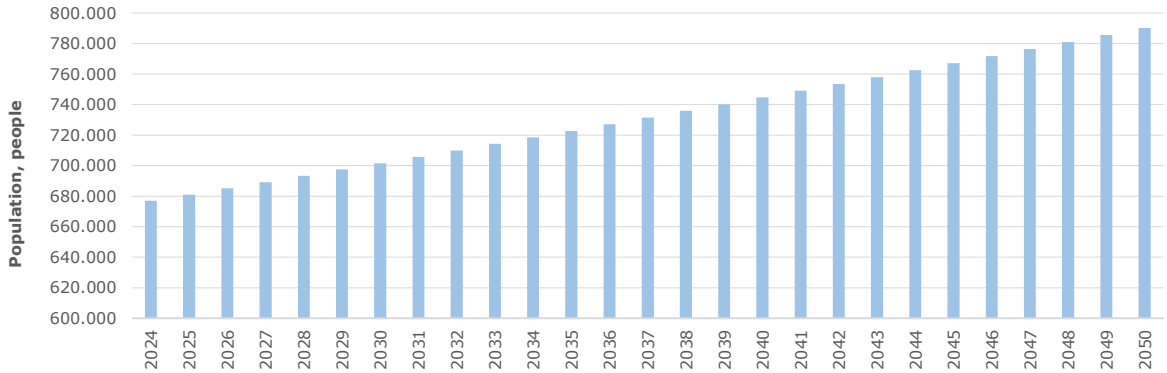


Figure 5-6. Population growth forecast in Chisinau, 2024–2050

As a result of population growth and the corresponding expansion of the building stock, there has been an increase in demand for thermal energy, both for heating newly constructed buildings and for DHW. The projected annual demand growth is approximately 0.4% for heating consumers connected to the CHP Source-1 / Source-2, 0.08% for consumers connected to the HOB-West, and 0.03% for those connected to the HOB-South. Meanwhile, the expected annual growth in demand for DHW supply is 0.5% for the entire population connected to the DH network.

Climate changes

Historical trend of rising external temperatures, leading to a decrease in heat demand

The analysis of future DH demand takes into account climate change and heating degree days (HDDs). Heating degree days, reflecting external temperature fluctuations, are a primary driver of DH demand, with colder external temperatures leading to higher heating needs. It should be noted that changes in external temperature affect only the consumption of thermal energy for heating.

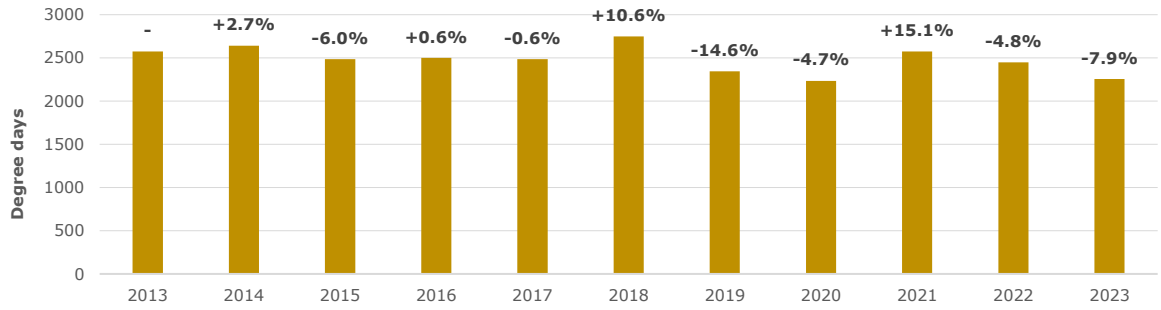


Figure 5-7. Historical data on heating degree days (HDD) in Chisinau, 2013-2023

Source: meteorological data sources

As shown in the diagram above, changes in the average external temperature during the heating season, and thus in HDDs, are not linear and do not show a constant increase. Some years exhibit temperature drops, while others show increases. For instance, 2018 recorded the lowest average external temperature during the heating season in the analysed period, which led to a rise in demand. This trend may repeat in the future despite the general trend of rising average external temperatures. Therefore, historical fluctuations in external temperatures during the heating season have been considered in the forecasting process.

An essential factor considered in the forecast is the anticipated impact of climate change. As external temperatures gradually increase, the need for heating is expected to decline, affecting both residential and non-residential DH customers. Climate projections indicate that, despite some fluctuations, average external temperatures will continue to rise, thereby reducing future demand for heating (see figure below).

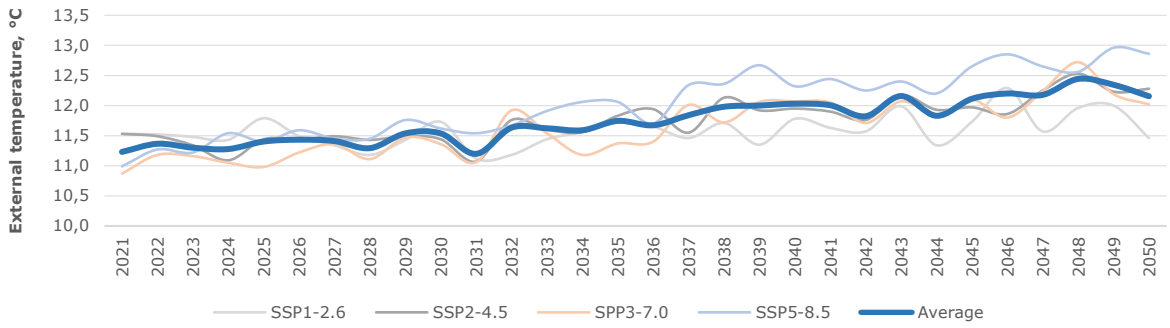


Figure 5-8. Forecast of external temperature changes in Chisinau, 2021–2050

Source: World Bank

To analyse the increase in external temperatures, an approach based on Shared Socioeconomic Pathways (SSPs) is used. These SSPs illustrate potential societal development scenarios, accounting for technological, political, and environmental changes. Each pathway outlines specific demographic and socio-economic trajectories that shape expected greenhouse gas emissions levels.

The SSP scenarios consider various factors, including demographics, economic development, inequality, technological changes, and policy orientations. These scenarios allow for the modelling of potential future trends in climate change and help forecast the impact of rising average external temperatures on thermal energy consumption. This methodology provides a robust foundation for projecting future DH demand in the face of climate change.

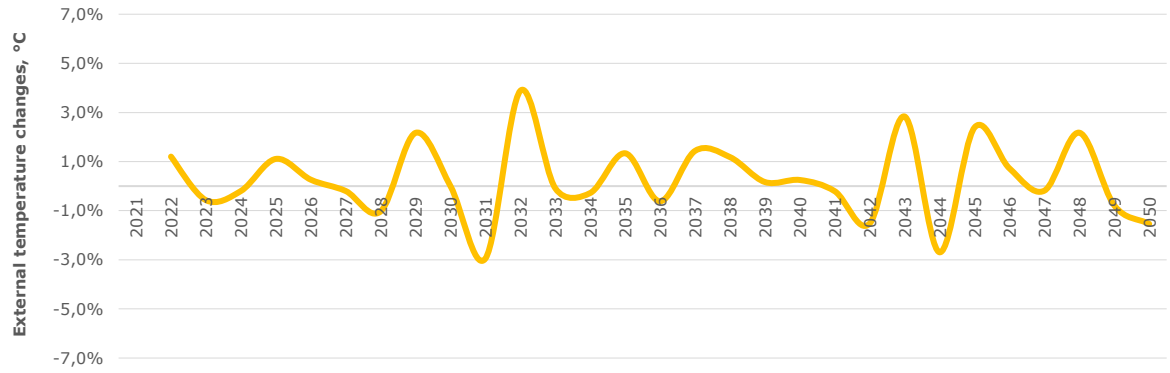


Figure 5-9. Trends in forecasted external temperature changes in Chisinau, 2021–2050

The World Bank's temperature forecasting results indicate year-to-year fluctuations in external temperatures, yet with a clear upward trend, averaging an annual increase of 0.28%. This steady rise in average temperatures is expected to directly reduce the demand for heating, as warmer conditions gradually lower the need for thermal energy. Accounting for this climate-driven reduction is essential for accurate DH demand forecasting over the long term.

Laying pipelines

Reduction in heat loss during transportation due to the annual replacement of pipelines with a long service life

One of the critical measures to improve the city's DH system is the replacement of outdated pipelines with modern ones to reduce network losses, thereby decreasing the demand for heat generation. The total length of large DH pipelines in the city amounts to 229,509 meters. Approximately a quarter of this length consists of pipelines that have been in operation for 40 years or more, which significantly increases the likelihood of leaks, energy losses, and costly repairs due to the deterioration of materials. These pipelines require priority replacement.

The diagram below shows the distribution of pipeline lengths by diameter and the share of each with an operational life of 40 years or more:

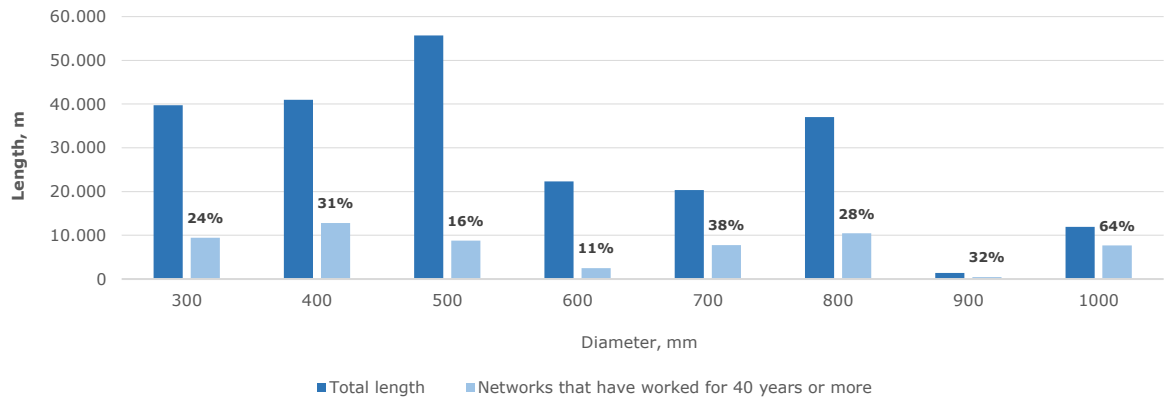


Figure 5-10. Heating supply pipelines

Source: Termoelectrica S.A.

The total network losses in 2021 amounted to 17.96%. This level of loss is considered high compared to industry averages, which typically range between 10% and 12% for well-maintained district heating systems. Consequently, the current loss rate exceeds the optimal benchmark by approximately 6-8%, indicating a pressing need for infrastructure upgrades to improve efficiency.

The table below provides a list of pipelines that require urgent replacement:

Table 5-6. Networks that have been in operation for 40 years or more and are due for replacement

Diameter, mm	300	400	500	600	700	800	900	1,000	Total
Length, m	9,414	12,842	8,802	2,490	7,755	10,481	438	7,666	59,888

The total length of pipelines requiring replacement is 59,888 meters, accounting for 26% of the overall network length. Pipeline replacements are gradually conducted as part of annual maintenance works. However, this is insufficient to cover the entire volume of aging infrastructure. A significant part of these replacements is planned within the scope of the *Termoelectrica Chisinau District Heating Project (EBRD)*, covering 15,000 m, and *The Optimization of Chisinau District Heating System Study (WB)*, targeting 40,400 m. The graph below illustrates the reduction in network losses as a result of pipeline replacements:

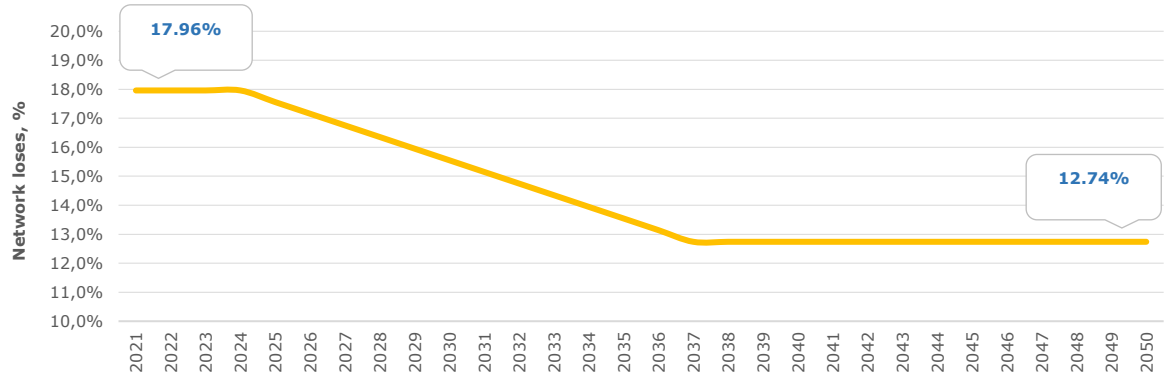


Figure 5-11. Forecast of reductions in losses in the network as a result of replacing heating supply pipelines

Overall, it is anticipated that losses in the network will decrease to 12.74% following the replacement of 59,888 m of pipelines that have been in operation for 40 years or more, and gradual replacement of other worn out DH pipes in the system.

5.1.2.3 Heat Demand Projection

5.1.2.3.1 Overview

The hourly forecast for heating and DHW demand involved both common and distinct components:

Common factors:

- **Network losses** were taken into account for both heating and DHW demand projections, as they impact overall consumption levels.

Distinct factors:

- Heating: the key factor influencing hourly demand distribution was the **external temperature**. Colder temperatures significantly increased hourly heating demand, making temperature fluctuations a critical component of the forecast.
- DHW: unlike heating, the hourly distribution of DHW demand was primarily determined by human **behaviour patterns**. External temperature did not impact DHW demand, as it remains relatively stable and independent of weather conditions.

This differentiation highlights the importance of accounting for unique drivers in forecasting hourly demand for heating and DHW within the DH system.

5.1.2.3.2 Impact of Historical Adjustments and Assumption

The analysis of historical adjustments and assumptions enabled the assessment of the impact of each significant factor on the baseline load, which was calculated based on 2021 data. To forecast future load dynamics, it was essential to account for historical changes that influenced the load between 2021 and the time of analysis, as well as assumptions about future conditions. The level of impact of each of these factors on the load is detailed above. This approach generated demand influence curves, which acted as drivers for both reducing the load during certain forecast periods and increasing it in others. These curves directly inform the adjustments to load forecasts, ensuring they account for seasonal and trend-based variations, while also capturing the cumulative effects of past changes and future projections. As a result, these curves provide a nuanced understanding of how historical and assumed factors shape demand dynamics, offering a more precise forecast of load requirements.

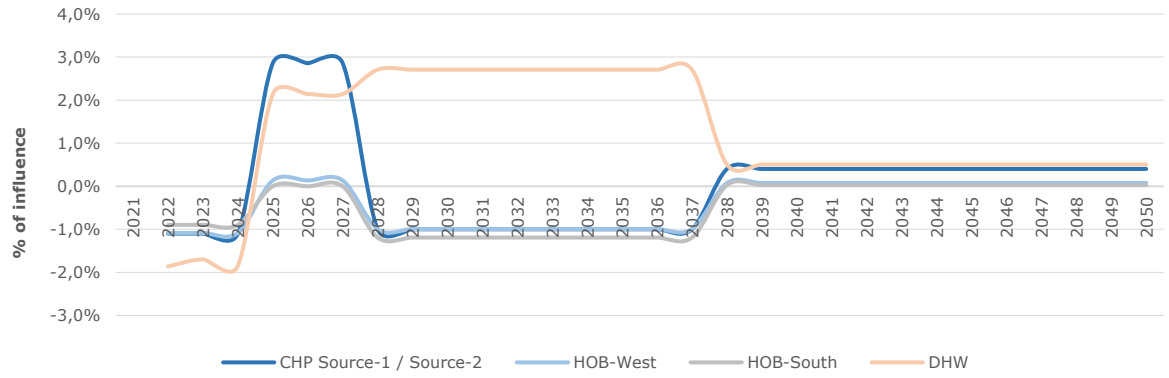


Figure 5-12. Impact of historical adjustments and assumptions on baseline load

As seen from the diagram, the main period of significant impact on the baseline load occurred between 2022 and 2037. The beginning of this period (2022-2024) was marked by the influence of historical adjustments, while subsequent variations were driven by existing assumptions. Beyond this timeframe, only minor adjustments take place, influenced primarily by steady factors such as population growth and rising temperatures, which have a continuous but less dynamic effect on the baseline load.

The application of key influencing factors enabled the adjustment of the baseline load and allowed for forecasting its change through to 2050:

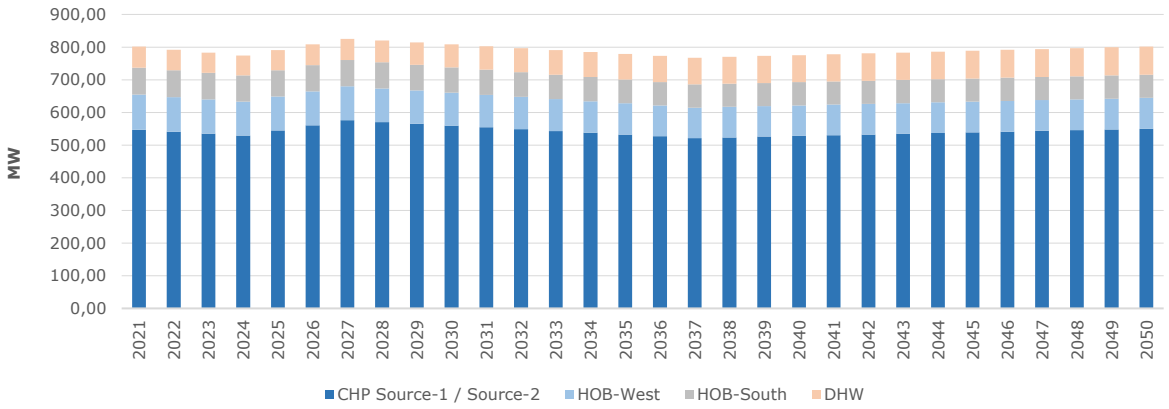


Figure 5-13. Baseline load forecast considers the influence of historical adjustments and assumptions

As illustrated in the diagram, the baseline load over the reviewed period shows only slight fluctuations, with some factors driving reductions while others contribute to increases, maintaining the overall trend within a consistent range. In summary, energy efficiency measures, which positively impact baseline load reduction, create capacity to connect new consumers, thereby increasing load demands. This approach enhances service quality and expands the customer base, while overall demand for generation remains stable.

By the end of the forecast period, the baseline load across different sources and services shows varied trends, reflecting the specific factors influencing each area:

- **CHP Source-1 / Source-2**: experiences a slight increase in baseline load, rising by 1%, indicating stability in demand with minor adjustments over time.

- **HOB-West**: registers a 12% decline in baseline load, likely driven by shifts in demand patterns and efficiency measures.
- **HOB-South**: shows a reduction of 14% in baseline load, following similar influences as HOB-West.
- **DHW**: notably, the baseline load for DHW sees the most significant rise, increasing by 35%. However, this substantial increase in DHW load does not heavily impact the overall DH system, as DHW still comprises only 11% of the total load, making its influence on system-wide demand relatively minor.

This distribution highlights the balanced dynamics between load reductions in certain areas and growth in others, allowing for overall system efficiency and consistent demand management.

5.1.2.3.3 Heat Demand Profile

Based on the projected peak load for each heat source and hot water supply, along with temperature forecasts and historical trends in external temperature changes (including recurring peaks and lows that characterise the city's weather patterns), the total annual heat consumption for heating and DHW has been calculated through to 2050.

Additionally, human behaviour patterns were considered, particularly for DHW, where hourly demand distribution was influenced by typical usage times and daily routines. Network losses were also factored into the calculations, ensuring an accurate representation of the energy required to meet demand.

The process began with calculating hourly demand, which provided a detailed basis for estimating total annual consumption across the DH system:

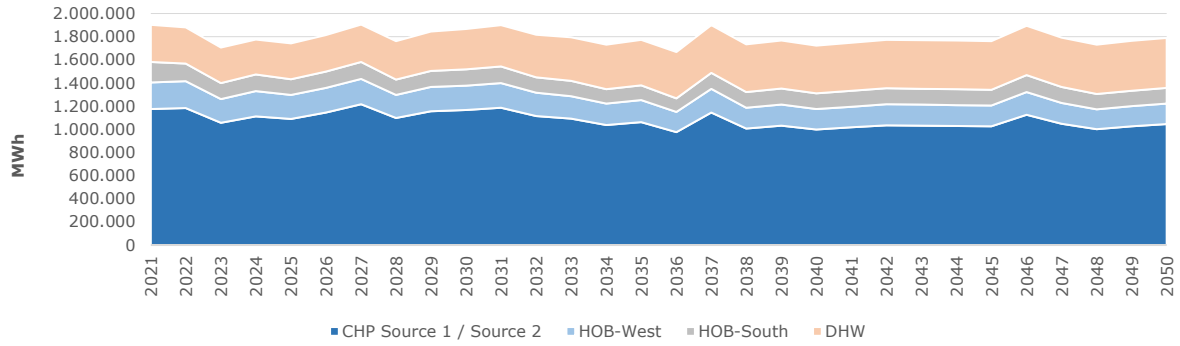


Figure 5-14. Forecast of heat energy consumption for DH and DHW in Chisinau, 2021–2050

The average heat consumption over the analysed period was 1,792,598 MWh, indicating a general, though modest, trend of decreasing demand. In 2021, consumption began at 1,900,826 MWh, and while fluctuations were observed, there was an overall downward trajectory in subsequent years.

The highest consumption was recorded in 2027, reaching 1,904,171 MWh, while the lowest was in 2036, at 1,667,945 MWh. Notably, the heating degree days (HDDs) had a significant influence on consumption trends. For instance, in 2037, there was a marked increase in consumption (13.8%) compared to the previous year, driven by a drop in external temperatures and an 18.1% rise in HDDs. This resulted in higher demand for heating services.

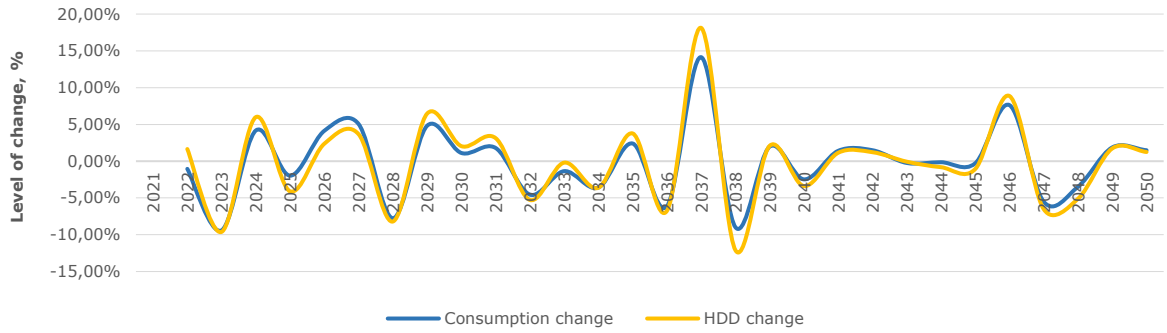


Figure 5-15. Changes in the forecast of heat energy consumption for heating and DHW and HDD in Chisinau, 2021–2050

The comparison between consumption trends and HDDs over the period from 2021 to 2050 highlights the correlation between these two factors. Since the majority of heat consumption is dedicated to heating, HDD variations directly impact demand. This correlation supports the notion that, despite ongoing changes in the consumer base and the implementation of measures aimed at reducing demand and consumption, there may still be instances where demand increases due to significant weather-related factors. Furthermore, while the general trend shows a rise in average annual temperatures, it is not uncommon for external temperatures to dip during the heating season, thus influencing demand and contributing to an overall increase in heat consumption.

6. Technical and Economic Analysis

6.1 Technical Configurations and Type of Technology

In accordance with the project task, the needs of the Moldova energy system and Chisinau DHS, possible development scenarios of the new energy production plant were defined.

When defining the scenarios, the following technical solutions were taken into account:

- Combined cycle cogeneration power plants
- Gas turbine cogeneration with heat recovery boiler
- CHP gas engines
- Waste-to-energy (WtE) plants
- Heat pumps
- Electric hot water boilers
- Solar collectors
- Thermal energy storage

6.2 Description of Different Alternatives for the New High Efficiency CHP Plant Based on Heat Load in Chisinau and Electricity Demand in Moldova

Technical solutions considered when defining considered scenarios are defined and elaborated in the following subchapters, according to the needs of the project areas and initial assumptions. Following the project assignment and clients' needs, following technical solutions are analysed:

- CHP production units
- Complementary units

CHP production units are the main scope of this analysis and represent major production units which will cover majority of energy needs of the future system. They need to be able to cover majority of heat demand of the district heating system when existing CHP units are decommissioned.

Complementary units are units that are considered for investment in the future to meet specific national and/or local goals and encompass renewable energy sources (RES), like solar collectors and heat pumps, waste-to-energy (WtE) plant, as well as electric water boiler and energy storage system.

6.2.1 CHP production units

As the primary goal of the feasibility study for the new CHP plant in Chisinau is to analyse the viability of various alternatives for a long-term combined heat and power solution which micro-location must be provided exclusively within the existing boundaries of the existing CHP Source 1 plant.

CHP plants include plants that produce electricity and heat in one process. This could be a classic steam boiler and condensing or backpressure steam turbine, a gas turbine plant and a low-pressure steam / hot water heat recovery boiler (utilization of waste heat), or CHP gas powered ICE. Classical cogeneration plants based on classic steam boilers which are built primarily for the covering large heat consumption and thus have low electricity generation efficiency and flexibility, for the purposes of this Study, will not be considered.

CHP production units represent major production units which will cover majority of energy needs of the future system. In the study, the following technical-technological solutions are considered for scenario development.

- **Combined cycle cogeneration plants**
- **Gas turbine with heat recovery boiler**
- **CHP gas engines**

As per analysis of the existing location of CHP Source 1 plant, possibility of partial expansion to the northeast of the existing CHP plant is identified. In consultation with the client, micro location for building new CHP plant is further refined and depicted in Figure below.

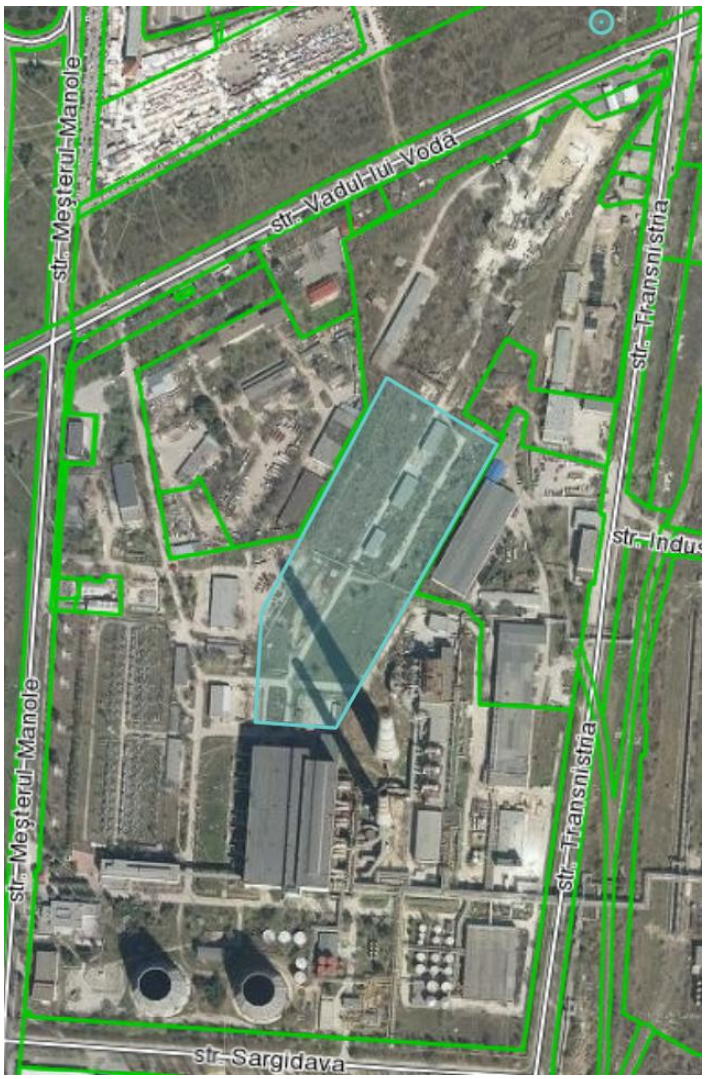


Figure 6-1. Possible area for micro location for building CHP plant within CHP Source 1 location

6.2.1.1 Combined cycle cogeneration power plants

The first type of possible options of new energy source is cogeneration system which features a **gas turbine**, **Heat Recovery Steam Boilers** (HRSB), **steam turbine** and **auxiliary facilities**.

Gas turbines

In cogeneration units with a **gas turbine**, natural gas is mixed with compressed air and burned in the combustion chamber. Then the gases - products of combustion move the rotor blades of the gas turbine, so the power is transmitted via the common shaft to the rotor of the electricity generator. The thermal energy of the flue gases can be used in the Heat Recovery Steam Boilers and produce technological steam.

There are two types of gas turbines: aeroderivative and heavy-duty gas turbines which are shown in the following figures (Figure 6-2, Figure 6-3, and Figure 6-4).

Aeroderivative gas turbines are taken from the technology of making aircraft engines. They are developed for installation in small spaces, they are small in weight and have modular design. Advanced materials are used for their production, which makes it possible to achieve high efficiency (≈ 41%). They have the ability to be put into operation very quickly and quick ramp up to nominal power with little consequences due to dynamic stresses. They are designed for simple and quick moving and maneuvering, which enables quick installation, efficient maintenance and considerably shortens downtime and increases flexibility and working time.

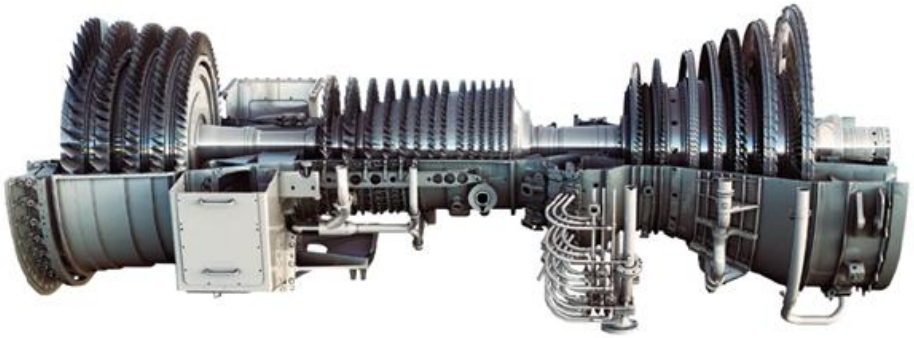


Figure 6-2. Aeroderivative gas turbine GE LM6000 PF+

The housing and moving parts of the **heavy-duty gas turbine** are intended exclusively for stationary operation, i.e. for work on land, so their mass and volume are not limited, and the technology is taken from the production of steam turbines. It is usually distinguished from an aeroderivative turbine by its single-shaft design, and it operates at a constant speed. The bearings of the shafts are hydrodynamic, while in the case of aeroderivative they are cylindrical or spherical. The construction and size of the combustion chamber itself enables lower compression ratios, which reduces emissions and increases the flexibility of fuel use. Maintenance of these turbines requires more time and human resources.

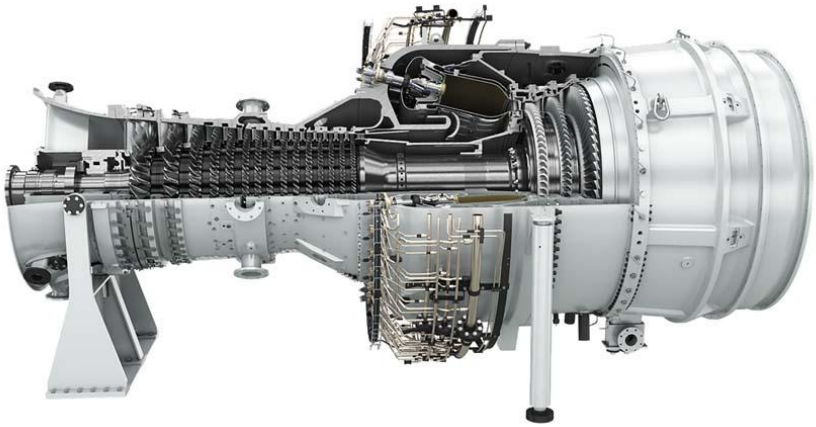


Figure 6-3. Heavy-duty gas turbine Siemens SGT800

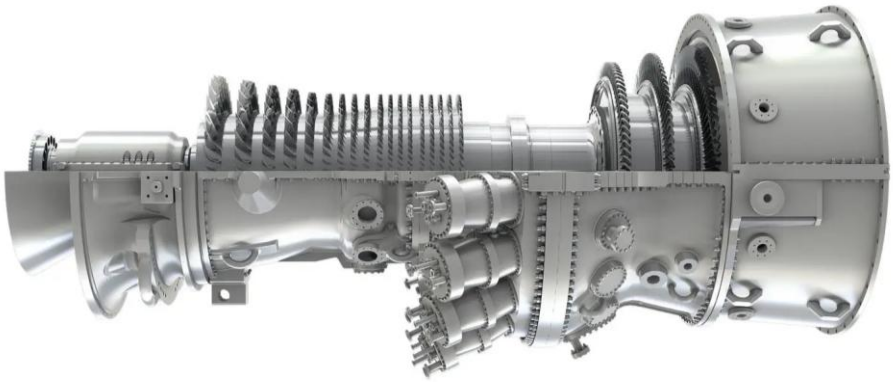


Figure 6-4. Heavy-duty gas turbine GE 9F.04

In Combined cycle cogeneration power plants, integration of heavy-duty gas turbines is considered.

The combustion of natural gas as a primary fuel in gas turbines produces exhaust gases which are, in combined cycle power plants, routed from the turbine diffuser into dual pressure HRSBHRSBs.

Heat Recovery Steam Boiler (HRSB)

A configuration with a **two-pressure boiler** was considered, and the term two-pressure boiler means complete **separation** of the **high-pressure** and **low-pressure steam** production systems (there are two drums, one at high and one at low pressure, from which water evaporates). Steam produced in the high-pressure system flows through the high-pressure stages of the steam turbine, and in the low-pressure stages, to the steam that was not removed in the high-pressure stages flows, steam produced in the low-pressure system is also added. The advantages of the two-pressure system are expressed in boilers with relatively **low flue gas parameters**, as is the case in waste heat boilers. In such boilers, regulation is performed according to the minimum temperature difference on the exchange surfaces, not the flue gas temperature. The minimum temperature difference as the main limitation makes it impossible to lower the temperature of the flue gases to the desired low level (due to the fact that after the exchange of heat to generate steam at high pressure, which is certainly needed for the production of electricity, the temperature of the flue gases remains high). With the economizer surfaces, the exit temperature of the flue gases can be further lowered, but not as by adding an additional evaporator stage at low pressure (it reduces the

temperature of the flue gases more than the economizer because it uses the latent heat of the water).

Thus, the dual pressure HRSB is an integral component of combined cycle cogeneration plants designed to optimize the recovery of waste heat from gas turbine exhaust gases. It consists of a series of heat exchangers and drum arranged to operate at two different pressure levels—high and low pressure as it can be seen on Figure 6-5.

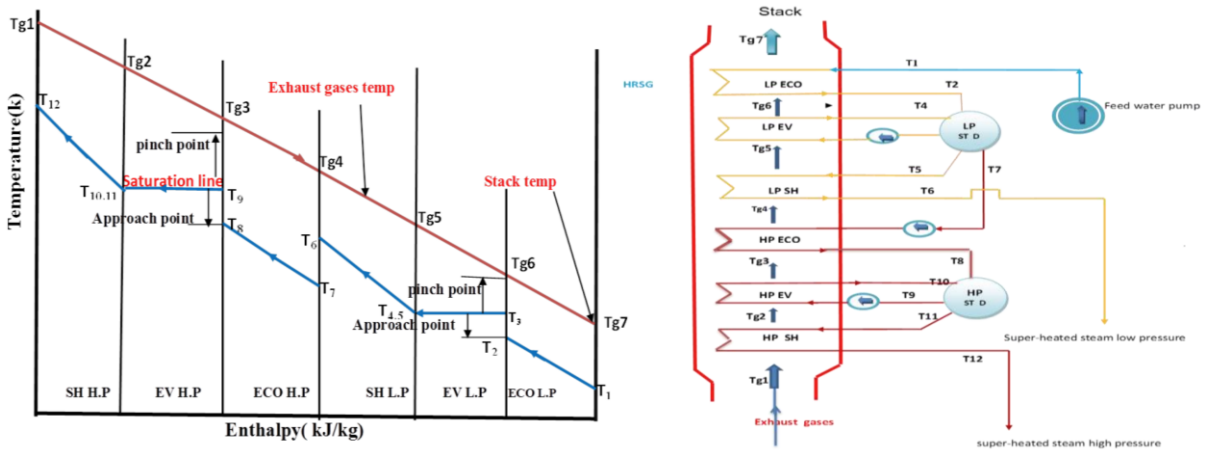


Figure 6-5. Example of the dual pressure heat recovery steam boiler with temperature distribution on (Temperature - Enthalpy) diagram

For each pressure level, the HRSB incorporates three main types of heat exchangers: the economizer, the evaporator, and the superheater. The **economizer** preheats the feedwater to a temperature close to its saturation point. The **evaporator** then converts this preheated water into saturated steam. Finally, the **superheater** heats the saturated steam to a superheated state suitable for driving steam turbines or fulfilling process steam needs (T_1=89°C, T_{12}=535°C, T_{g1}=600°C, T_{g7}=104°C).

Each heat exchanger comprises a bundle of tubes, which can be arranged either in-line or staggered, depending on the manufacturer's design specifications. The working fluid (water or steam) flows horizontally through these tubes, while the exhaust gases flow vertically across them. This perpendicular flow arrangement classifies each heat exchanger in the HRSB as a cross-flow heat exchanger.

Forced circulation is employed using circulation pumps dedicated to each pressure level (refer to Figure 6-5). **Steam drums** are incorporated to separate the saturated steam from the water-steam mixture exiting the evaporator.

Due to the relatively low heat transfer coefficients on the side of exhaust gases from the turbine compared to those of the working fluid in the evaporator and economizer, **finned tubes** are utilized to enhance heat transfer on the gas side. The fins can be either solid or serrated, selected based on performance requirements and manufacturing considerations.

Critical parameters influencing the HRSB's performance include the **pinch point**, **approach point**, and the gas-side pressure drop through the heat recovery system. The **pinch point** is defined as the temperature difference between the gas temperature leaving the evaporator section and the saturation temperature corresponding to the steam pressure in that section. The **approach point**

is the difference between the saturation temperature of the fluid and its inlet temperature into the evaporator. These parameters are vital for optimizing the effectiveness of heat exchange and are carefully considered during the design phase.

Figure 6-5 illustrates a Temperature-Enthalpy (T-h) diagram showing the temperature profiles for the dual-pressure levels, providing a visual representation of the heat exchange processes occurring within the HRSB.

Steam turbine

High pressure steam from HRSB is then delivered to high pressure section of steam turbine and low-pressure steam to low pressure section of steam turbine. The turbine steam path inside steam turbine converts thermal energy into mechanical energy through a series of stages that capture the momentum from the expanding steam. These impulses and reactions are used to drive the shaft, which is connected to the generator to produce electricity.

The **counter-pressure turbine** is the most widespread among all industrial units, it is especially suitable for installation in power plants which need a lot of heat production. It is characteristic of all counter-pressure turbines that the entire amount of steam flowing through the turbine serves for heating after passing through the turbine, so that the heat contained in the output steam can be used in coupling process. That is why the heating plant with a counter-pressure unit does **minimizes losses** due to not utilizing the heat of the outgoing steam, which is the biggest loss of the condensing blocks. This advantage of connecting the production of electricity and heat is so great that no other solution can compare economically with the installation of counter-pressure units. However, in this case the production of electricity and heat is **coupled** in the way that it is impossible to produce electricity if an adequate amount of steam for heating is not consumed at the same time. Usually, the device is dimensioned in such a way that all the steam from the boiler passes through the turbine, in the amount needed for heating, while all the produced electricity is placed in the power system.

Certain flexibility can be achieved by installing reduction-cooling stations, which direct part of the steam from the boiler to the steam distributor for technology/heating for consumers (by-pass steam turbine), while the remaining amount is passed through the steam turbine and further distributed to consumers.

In industrial power plants that, in addition to electricity, supply consumers with considerable amounts of steam for heating at different pressures, counter-pressure turbines with steam extraction can be installed (Figure 6-6).

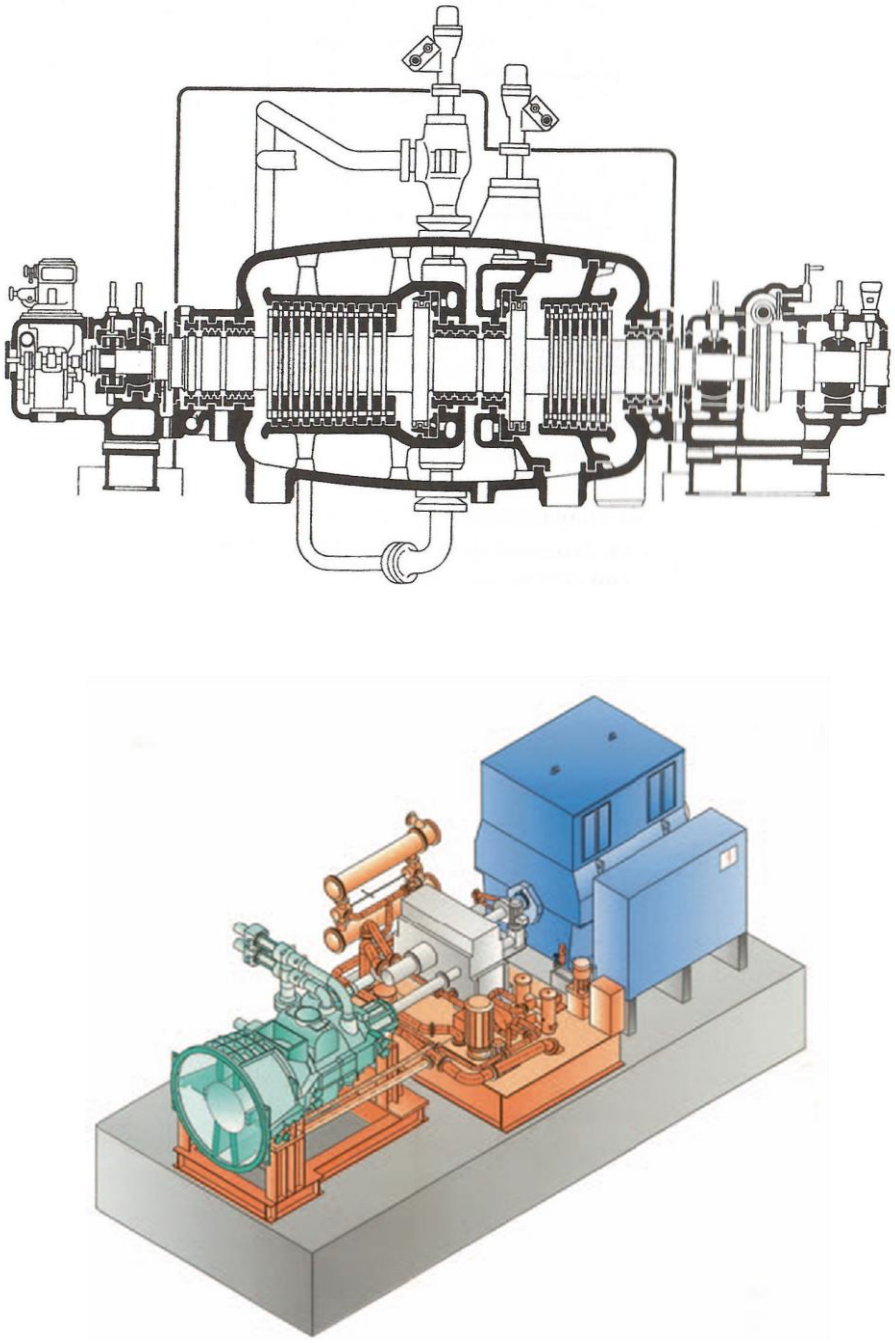


Figure 6-6. Example of counter pressure steam turbine with steam extraction

Fresh steam of pressure p1 first enters the **high-pressure part** of the turbine (HP), where it expands to pressure pe, giving up part of its energy for the purpose of generating electricity. After passing through the high-pressure part of the turbine, the steam stream is divided. Part of the steam is **extracted** from the turbine and taken to steam consumers for heating at a higher pressure pe. The rest of the steam is mixed with low-pressure steam from HRSB and passes through the **low-pressure part** of the turbine (LP), where the expansion process takes place from the pressure pe to p2, which produces additional mechanical energy to drive the electric current generator. Steam

after which passed through the low-pressure part of the turbine goes to the steam consumers for heating at a lower pressure p2.

The heat utilization is as good as that of counter pressure turbines without stream extraction, as all the steam streams coming out of the turbine are taken to the heat consumers. Due to this, counter pressure steam turbine with steam extraction is used in all analysed combined circle power plants.

Auxiliary facilities

In order to better utilize the waste heat of the steam-turbine cycle, the option of using a heating condenser instead of the classic design of a condenser cooled by cooling water was analysed.

The main advantage of using a **heating condenser** is the utilization of waste heat that would otherwise be thrown away into nature. Instead of condensing the steam from the last stage of the turbine with cooling water, the steam in the heating condenser condenses, transferring the heat to the district heating water, which is used for covering DHS heating demand during the heating season

In order to ensure the cooling of the DHS water even in periods without the need for heating or with a reduced need, an additional cooling of the district heating water is necessary.

This additional **cooling exchanger** of main water can be directly cooled by air (the version of an air cooler or so-called dry cooler) or by cooling water that is further cooled in e.g. cooling towers. However, the usual solution is to use a dry cooler due to the similarity of network water temperatures in the heating season and the temperatures achieved by dry air cooler in the summer. In this way, a similar mode of operation of the steam turbine is ensured in summer and winter (similar temperatures or condensation pressures).

6.2.1.2 Connection points within the scope of construction of a new block

Fitting the new block into the existing system of the CHP Source 1 at the operational level implies defining the connection points of the new block system to the existing systems of the CHP Source 1, as well as the eventual reconstruction of individual existing systems or their parts.

The points of connection within the scope of the construction of a new block are elaborated in the following paragraphs.

- Natural gas system

The establishment of a new combined heat and power facility near CHP Source 1 in Chisinau is closely linked to the existing natural gas supply framework. As of February 2025, Moldova no longer receives natural gas directly from Russia following Gazprom's suspension of supplies on January 1, 2025, due to contractual disputes and alleged payment arrears (to be noted the natural gas supplied from Gazprom since 2022 was transferred to the Transnistrian region). Moldova has shifted to European energy markets for natural gas procurement starting with 2022, relying on the Iași-Ungheni-Chișinău pipeline, which connects the country with Romania.

In the past period, the main operator of Moldova's natural gas transmission system was **Moldovatransgaz**. Moldovatransgaz is a subsidiary of Moldovagaz, which is a joint stock company with significant Russian ownership by Gazprom. **Moldovagaz** is responsible for gas distribution and supply within Moldova, while Moldovatransgaz specifically manages the transmission infrastructure.

In recent years, Moldova has been diversifying its natural gas import routes to reduce dependence on Gazprom. This has included projects to connect to the European gas network through Romania, with one of the key infrastructures being the **Iasi-Ungheni-Chișinău gas pipeline**. This pipeline is operated by **Vestmoldtransgaz**, which is a Moldovan company owned by Transgaz, the Romanian

gas transmission system operator. This connection enables Moldova to access gas supplies from other sources within the EU, enhancing its energy security and transmission flexibility.

Since October 19, 2023, "Vestmoldtransgaz" has been the sole operator of the gas transmission system (operating also the Moldovatransgaz transmission network).

The infrastructure leading to the Gas Distribution Station (GDS) operates under a pressure regime ranging from 28 to 33 bar(g). This pressure is subsequently reduced to approximately 6 bar after passing through the GDS. For the efficient functioning of the Combined Cycle Power Plant (CCPP), it is crucial that the gas pressure at the inlet of the gas turbine exceeds 30 bar(g).



Figure 6-7. Moldova natural gas transmission and distribution lines, by Moldovatransgaz

This requirement poses particular challenges when considering the integration of a new Combined Heat and Power (CHP) system with the existing gas pipeline infrastructure.

To address these challenges, one viable solution is the installation of a compressor station on the CHP premises. This station would be responsible for increasing the gas pressure from its post-GDS level to the required operational threshold. Although the implementation of a compressor station

would lead to an increase in electricity consumption, it provides an effective method to achieve the necessary pressure levels without extensive modifications to the existing pipeline network.

A significant challenge in this context is the absence or severe limitation of a suitable corridor for pipeline construction. The proposed pipeline extension from the high-pressure transmission network would need to cover a distance of approximately 3 km. The construction of such a pipeline is complicated by spatial constraints and the need to comply with stringent construction standards and urban planning regulations currently applicable in the Republic of Moldova. By opting for a compressor station, the requirement for this extensive pipeline construction could be negated, which is a critical consideration given the physical and regulatory limitations.

There are two natural gas pipelines to CHP Source-1. One natural gas pipeline was originally designed to handle a maximum supply pressure of 6 bar(g), with a corresponding maximum flow rate of 300.000 m^3/h; however, it is operated at 3 bar(g) due to the technical conditions of the existing pipeline. There is a second gas pipeline with design pressure of 3 bar(g) and maximum flow rate of 150.000 m^3/h. The site currently features two pressure regulating and metering stations, one designed for 6 bar(g) and one for 3 bar(g); the 3 bar(g) one is used.

During periods of peak demand in winter, the natural gas pressure has been observed to drop to as low as 1 bar(g), presenting additional challenges for maintaining adequate supply. CHP Source 1, a major consumer within this network, requires a substantial 90.000 m^3/h of natural gas at maximum load conditions, typically witnessed during the coldest ambient temperatures. On average, the facility's consumption hovers around 60.000 m^3/h. The plant's natural gas intake boundary is established at the pressure regulation station situated within the confines of CHP Source 1.

Integrating a new CHP system near CHP Source 1 involves navigating a complex interplay of technical, regulatory, and logistical factors. The pressure requirements must be meticulously managed to ensure seamless integration with the existing infrastructure, while the physical constraints of pipeline construction necessitate innovative solutions like compressor stations. Additionally, adherence to safety, environmental, and urban planning regulations is paramount, requiring a holistic and well-coordinated approach to this integration project. This comprehensive strategy ensures that the benefits of the new CHP system are realized without compromising operational efficiency or regulatory compliance.

Summary of the Natural Gas Supply Infrastructure

- **CHP Source 1 Capacity**: The facility has a maximum available natural gas capacity of 150.000 m^3/h (300.000 m^3/h if using both pipelines) at a delivery pressure of 3 bar(g), with potential to be enhanced to a capacity of 300.000 m^3/h at 6 bar(g) within the current safety regulations.
- **Existing Connections**: The current infrastructure at CHP Source 1 necessitates the operation of gas booster compressors to elevate incoming pressure to approximately 45 bar for optimal CHP operation.
- **Regional Network**: The natural gas network in the vicinity of Chisinau, including pressure reducing stations, is designed to support the fuel demands of new power generation capacities. This includes the Iasi-Ungheni-Chisinau pipeline, which aims to enhance gas supply reliability by increasing the capacity available for natural gas importation.

In order for estimation of the maxim available capacity of the delivery point at 6 bar(g), it is crucial for comparison of the maximum consumption of naturel gas on the hourly level for each variant of the CHP. Therefore, on the following table no. 23 all the needed capacities as well as the maximum available capacity on this level of natural gas pressure, considering the maximum consumption of the CHP Source 1 in the highest pick hours during the year, are presented.

It has to be concluded on the connection point where CHP Source 1 is connected, there is enough natural gas flow for CHP Source 1 and the new CHP power plant for continuously operation of both facilities.

Table 6-1. Natural gas consumption and available capacities

Variant	Variant description	Gross power output of one unit	Power Efficiency	Net heat value of one unit	Gas units	Natural gas Lower heating value (LHV)		Natural gas consumption	Maximum consumption of natural gas of Source 1 Gross Power of 240 MW + HOB 1 & 2		Maximum available natural gas capacity on 6 bar pressure gas capacity	Surplus of natural gas availability
		MW	%	kJ/kWh	No.	kcal/m³	kJ/m³	m³/h	Gcal/h	m³/h	m³/h	m³/h
A	**CHP (type 1)** [2 x SGT800 + 2 x HRSB + ST]	62,5	41,1	8.759	2			**32.049**				**157.221**
B	**CHP (type 2)** [3 x SGT800 + 3 x HRSB + ST]	62,5	41,1	8.759	3			**48.074**				**141.196**
C	**CHP (type 3)** [GT 9G.04 + 1 x HRSB + ST]	288	38,7	9.295	1	8.164	34.162	**78.360**	904	110.730	**300.000**	**110.910**
D	**CHP (type 4)** [3 x GT LM6000 + 3 x HRHB]	53,9	40,8	8.817	3			**41.733**				**147.537**
E	**CHP (type 5)** [Gas engines J920 FleXtra]	10,7	47,4	7.596	18			**90.562**				**98.708**

Note: The route of the gas pipeline from the transmission network to the CHP Source-1 site does not transit populated/residential areas. Internationally, in other countries (Croatia for example) there is experience and regulations for installing high-pressure networks via urban areas. Thus, when preparing for a project based on gas turbines, it is highly recommended to assess the possibility to install a high-pressure gas pipeline from the transmission network to CHP Source-1 – to avoid the costs for compressor station and the energy costs for gas compression (e.g., for CHP Type-2, the electricity consumption for gas compression would be circa 3 MW). This could be possible by adopting practices and regulations used in other countries (or eventually identifying and approving a special solution for such a pipeline, with the necessary safeguards).

- Feed water preparation system

The new block will be integrated with a newly installed feed water preparation system, replacing the outdated existing system that requires significant refurbishment. In this setup, chemically treated water will be supplied to the feed water tank, functioning as part of the deaerator.

- Steam turbine cooling water system (condenser cooling)

The cooling system of the new block will be integrated with newly installed dry cooling towers, ensuring efficient heat dissipation and improved operational reliability.

- Waste and oily water system

The waste and oily water system must be connected to the existing wastewater system.

- Connection to the power grid

Having in mind that new CHP will be located in the vicinity of existing 110 kV substation (SS) CHP Source 1, it is convenient to use existing infrastructure for connection of new power plant.

The existing substation has double busbar with auxiliary busbar arrangement of primary circuits that guarantee high reliability of supply and flexibility of operation. 110 kV switchyard consist of 20 bays. It has strong integration to the 110 kV grid by eleven 110 kV lines. Two 110 kV lines are connecting SS CHP Source 1 to 110/330/(400) kV SS Chisinau. One 110 kV line is connecting SS CHP Source 1 to 110/330/(400) kV SS Straseni. This substation is hosting existing CHP Source 1 with installed capacity of about 250 MW, meaning that it is designed to evacuate power within a range of 250 MW or even higher.

110 kV circuit breakers have robust basic parameters, In = 2000 A and Isc = 57.8 kA (Ssc = 11,000 MVA). Existing equipment of the CET Source 1 distribution facility is outdated, with frequent cases of connection failures, lack of spare parts, outdated relay protection equipment, with insulation resistance at the lower limit, degraded concrete structures. Having in mind the age and condition of high voltage and secondary equipment in the substation, the Client should consider modernization of the equipment while keeping the existing design parameters. Modernization cost of existing 110 kV switchyard comprising both primary and secondary equipment is estimated on 10 million euros.

Practically, replacement of CHP Source 1 with new CHP with capacity up to 250 MW (alternatives A, B and D) do not impose any additional challenge to feed-in the power into the 110 kV grid.

Alternative E assumes installed capacity of new CHP of 193192 MW, but the flexibility of 18 gas engines and the structure of existing 110 kV local grid will allow smooth integration of this power.

Parallel operation of new CHP with the existing CHP Source 1 seems also possible (variants A, B, E and D), but detailed grid studies should be performed for power evacuation of the total production of both power plants. These grid studies usually are part of the connection process and carried out by Transmission System Operator, in line with the national Grid Code requirements. Grid studies are done using detailed model of complete 110 kV and 330 kV (400 kV) national grid, comprising steady state simulation to check normal (N-0) and contingency (N-1) regimes. Dynamic performance of the unit during faults and fault-ride-through requirements are checked using dynamic model of the power system.

Only alternative C with large gas and steam units of 440 MW is challenging for grid integration; this level of power is recommended to be connected at 330 kV level. The connection of new 440 MW CHP in alternative C is associated with high cost (7-8 times higher) due to higher voltage level, large distance and spatial complexity of routing to 330/110/35 kV SS Chisinau.

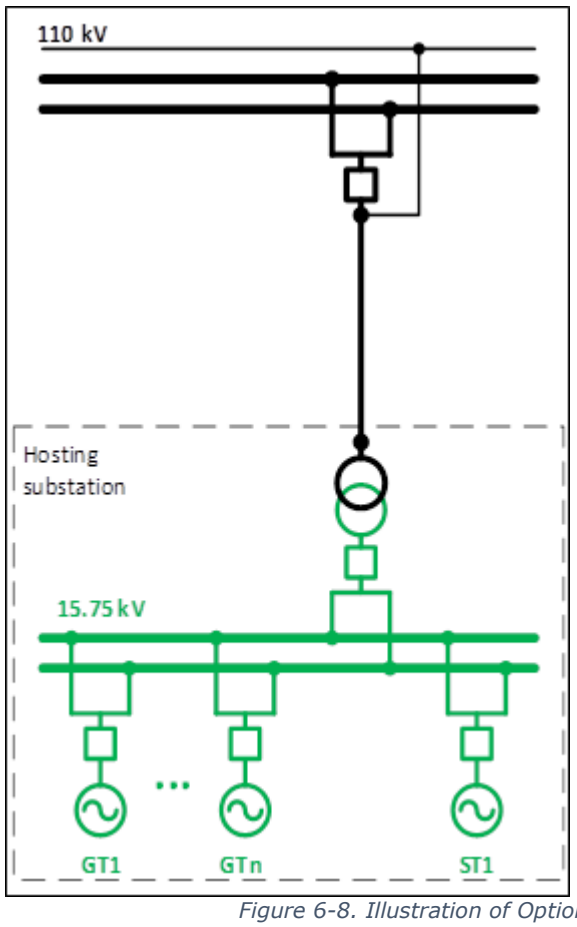
Consultant considered three options for connection arrangement of new CHP.

Option 1

Connection of each alternative of new CHP shall be of radial type and will comprise:

- one step-up transformer from generation to high-voltage level (ex. 15.75/110 kV or 15.75/330 kV),
- single radial high voltage line from generation site to PoC at existing grid

  - one 110 kV line (short cable of approx. 0.4 km for alternative A, B, D, E), or
  - 330 kV line (hybrid line comprising underground cable and overhead line for alternative C)
- direct coupling of step-up transformer and high voltage line,
- there is no need for high-voltage switchyard (bay) at generation side,
- one high-voltage outdoor switchgear (bay) for the connection line at the PoC (point of connection) at existing substation.



Advantages:
- low cost,
- small space requirements,
- simple maintenance and easy switching actions.

Disadvantages:
- single connection link, lower reliability.

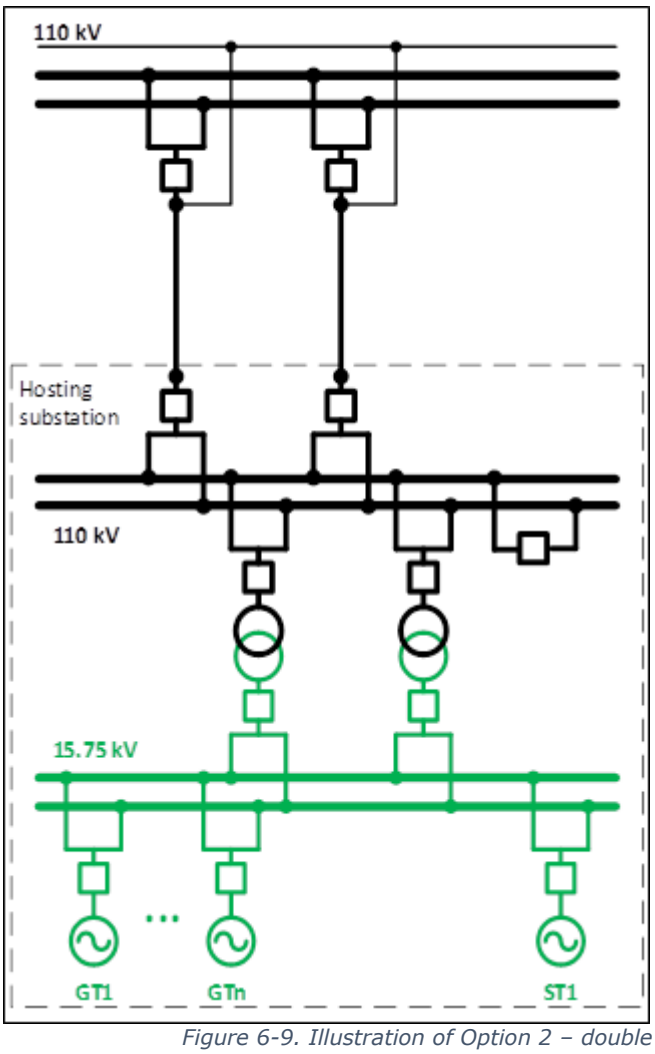
The reliability of connection could be improved by use of 4th single-core cable, kept in reserve and being activated to replace any faulted cable.

Figure 6-8. Illustration of Option 1 - radial connection of new CHP

Option 2

Connection of each alternative of new CHP shall be with double links and will comprise:

- two step-up transformers from generation to high-voltage level (ex. 15.75/110 kV or 15.75/330 kV),
- hosting substation with double busbar arrangement,
  - 15.75/110 kV substation with 110 kV double busbar arrangement (for alternative A, B, D, E), or
  - 15.75/330 kV substation with 330 kV double busbar arrangement (for alternative C)
- two radial high voltage lines from hosting substation to PoC at exising grid
  - 110 kV lines (short cables of approx. 0.4 km for alternative A, B, D, E), or
  - 330 kV line (hybrid lines comprising underground cable and overhead line for alternative C)
- five high-voltage outdoor bays for the lines and transformers at the hosting substation
- two high-voltage outdoor bays for the connection lines at the PoC at existing substation



Advantages:
- improved reliability,
- full redundancy,
- flexibility of operation.

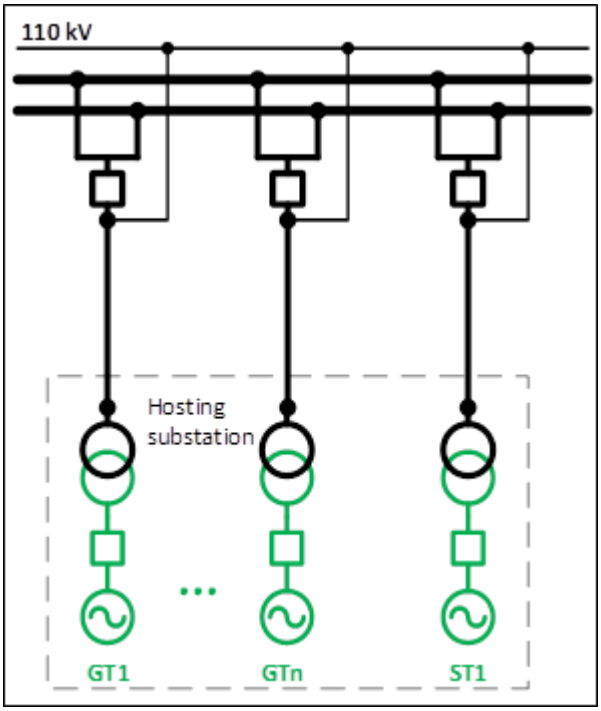
Disadvantages:
- highest cost,
- large space requirements,
- complex switching operations and maintenance.

Figure 6-9. Illustration of Option 2 – double links for connection of new CHP

Option 3

Connection of each alternative of new CHP shall be of radial/block type and will comprise:

- step-up transformer from every generation unit to high -voltage level (ex. 15.75/110 kV or 15.75/330 kV),
- single radial high voltage lines from generation site to PoC at exising grid:
  - 110 kV line from every generation unit (short cables of approx. 0.4 km for alternative A, B, D, E), or
  - 330 kV line from every generation unit (hybrid lines comprising underground cable and overhead line for alternative C).
- direct coupling of step-up transformer and high voltage line,
- no need for high-voltage switchyard (bay) at generation site,
- high-voltage outdoor bay for every connection line at the PoC at existing substation.



Advantages:
- medium cost,
- simple maintenance and easy switching actions.

Disadvantages:
- single connection link, lower reliability.

Figure 6-10. Illustration of Option 3 – radial/block connection of new CHP

Summary of connection options for different alternatives of new CHP with estimation of cost are given in the following table

Table 6-2. Summary of connection options for different alternatives for new CHP

	Alternative description	GT units [no]	ST units [no]	Power [MW]	Step-up TR [voltage ratio / winding /power]	Connection [line type / conductor / rating]
A	CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]	2	1	170	10,5/15,8/110 kV, 3w, 200 MVA	4 x single pole XLPE cable Al-1600 mm², 183 MVA
B	CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	3	1	250	10,5/15,8/110 kV, 3w, 300 MVA	4 x single pole XLPE cable Cu-2000 mm², 268 MVA
C	CHP (type 3) [GT 9G.04 + 1 x HRSB + ST]	1	1	440	10,5/15,8/330 kV, 3w, 500 MVA	OHL ACSR ACO-500 mm², 548 MVA 4 x single pole XLPE cable Al-1600 mm², 548 MVA
D	CHP (type 4) [3 x GT LM6000 + 3 x HRHB]	1	-	162	10,5/110 kV, 2w, 200 MVA	4 x single pole XLPE cable Al-1600 mm², 183 MVA
E	CHP (type 5) [Gas engines Jenbacher J920 FleXtra]	18	-	192,6	10,58/15,8/110 kV, 3w, 350 MVA	7 x single pole XLPE cable Al-1600 mm², 366 MVA

- Connection to DHS

The connection of the new unit to the system for heating of DHS water will be carried out in parallel with the existing exchangers of the existing CHP blocks at CHP Source 1, as it is shown in Figure 6-11. In this context, it will be necessary to carry out an appropriate reconstruction of the system, because the pipes are relatively large dimensions, the placement of which can represent a certain problem.

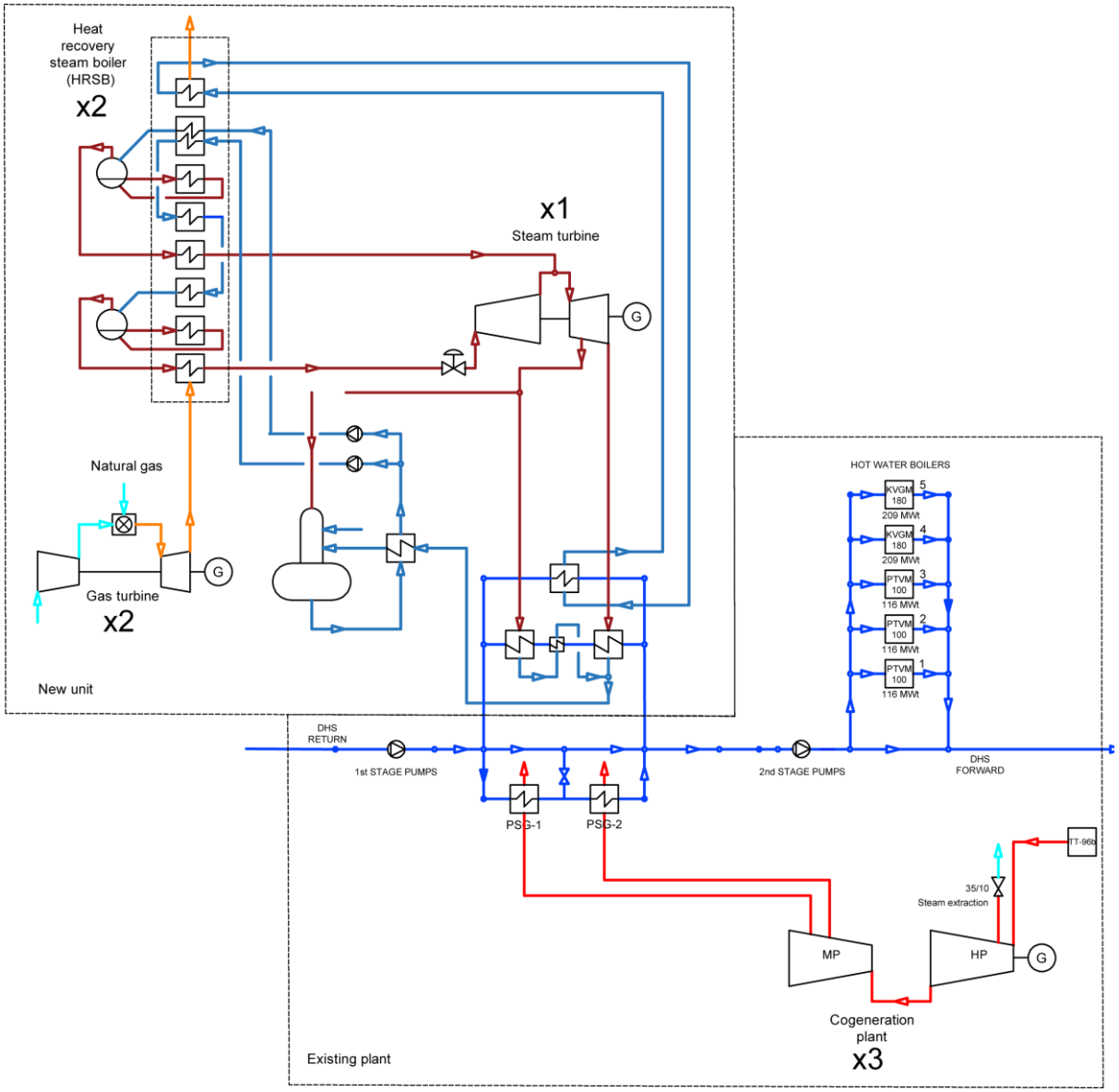


Figure 6-11. Connection to DHS

In following sub-chapters description of specific analysed combined cycle cogeneration power plant configurations is given.

6.2.1.2.1 CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

The first type of possible configuration of combined cycle cogeneration power plant is system based on **2x1 configuration with two gas turbines**, **two dual pressure heat recovery steam boilers** (HRSBs), and **one backpressure steam turbine**, as it can be seen on following figure.

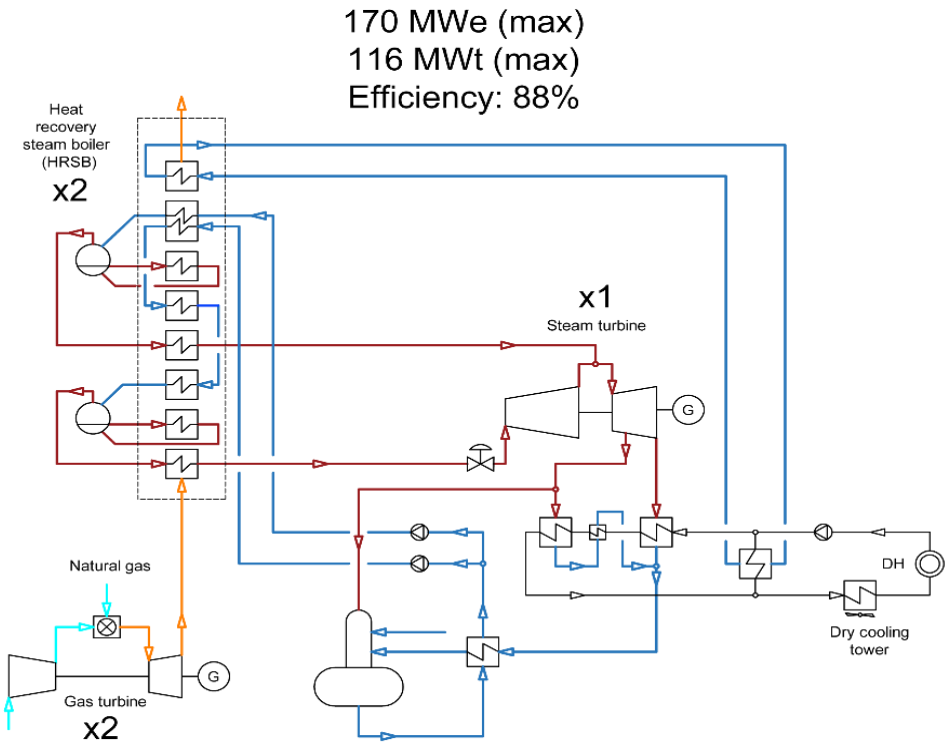


Figure 6-12. Combined cycle CHP configuration type 1 [2 x SGT800 + 2 x HRSB + ST]

Combining more gas turbines in combined cycle enables increased flexibility and meeting various energy needs. The following table (Table 6-3) shows the main characteristics of the considered gas turbine in this study and possible alternative in this power range.

Table 6-3. Considered and alternative gas turbines for CHP type 1 and 2 technical solutions

	Unit	Siemens SGT-800	GE 6B
Manufacturer	-	Siemens Energy	GE Vernova
Model	-	SGT-800	6B
Country of Origin	-	Sweden	France
Electrical output (ISO)	MW	62.5	45.0
Efficiency (open cycle)	%	41.1	33.4
NOx Emission (@15% O2)	ppm	15	8

The considered gas turbine, **Siemens SGT-800** gas turbine, is a high-efficiency industrial gas turbine renowned for its reliability, operational flexibility, and low emissions. The single-shaft engine of Siemens SGT-800 turbine is composed of a 2-bearing rotor with a 15-stage compressor and a 3-stage turbine.

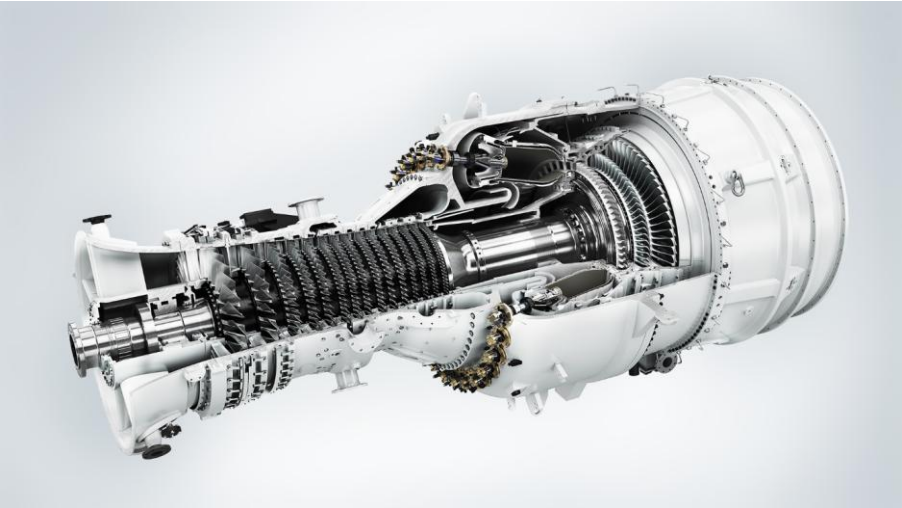


Figure 6-13. 3D view of Siemens SGT-800 gas turbine

It is particularly well-suited for combined heat and power (CHP) applications due to its high electrical efficiency and excellent steam-raising capability. Each SGT-800 gas turbine has a power output ranging from approximately 45.3MWe to 62.5 MWe, and gross electrical efficiency from 38,4 to 41,1% respectively in simple cycle power generation, which also has an influence on exhaust temperatures, exhaust mass flow and, sequacious, heat production potential.

Table 6-4. Parameters of SGT-800 gas turbine in correlation with power increase

	Unit	Value				
Power rating	**MW**	**45**	**50**	**56**	**57**	**62**
Gross power output	MW(e)	45.3	49.9	55.6	57.0	62,5
Frequency	Hz	50/60	50/60	50/60	50/60	50/60
Gross efficiency	%	38.4	39.4	39.5	40,1	41,1
Gross heat rate	kJ/kWh	9381	9147	9123	8970	8759
Turbine speed	rpm	6600	6600	6600	6600	6600
Pressure ratio	-	18.3:1	19.8:1	22.0:1	22,0:1	21,1:1
Exhaust mass flow	kg/s	115.1	124.7	137.7	136,6	135,5
Exhaust temperature	°C	574	560	564	565	596
NO_x emissions	ppmvd	≤ 15*	≤ 15*	≤ 15*	≤ 15*	15 - 25

To ensure operational security in case of natural gas supply distributions, the SGT-800 offers gas only, liquid only (Diesel No.2) or dual fuel (gas/liquid) with on-load fuel-changeover capability. The excellent fuel flexibility allows e.g. for high content of inert gases, hydrogen and heavy hydrocarbons in the gas fuel composition without any maintenance impact. The relatively low gas supply pressure requirement (27–31 bar[a] / 390–450 psi[a]) minimizes the need for extensive on-site gas compression. However, an additional compressor will still be required to ensure optimal pressure levels for efficient operation. The turbine combustion system is equipped with a dual-fuel burner system, enabling automatic switching between natural gas and Diesel No. 2 as needed. Fuel changeover can be initiated either manually or automatically, depending on grid and operational requirements. This capability ensures that the plant can maintain uninterrupted operation even in cases of gas supply shortages or pressure drops in the gas network. The fuel injection system

includes dedicated pumps, filters, and heaters to ensure optimal diesel atomization and combustion performance, maintaining efficiency and emission standards during backup operation.

The engine, equipped with DLE burners, is also capable to burn up to 75 vol% of hydrogen (H_2), thus it is capable to lead the way of energy transition to the use of sustainable fuels.

The combustion of natural gas in gas turbines produces exhaust gases (T: 596 °C, with excess air coefficient between 2 and 3), which are routed from the turbine diffuser into two dual pressure HRSBs where it exchanges heat with feedwater. One part of feedwater flows into the high-pressure section where it is converted into dry saturated steam which is further heated in the superheater to 520°C and 95 bar which are required operating parameters in the high-pressure section of the steam turbine. The rest of the water is preheated and flows into the low-pressure section where the dry saturated steam is separated and heated to 200°C and 7 bar which are parameters necessary for injection into the low-pressure section of the steam turbine.

The turbine steam path inside steam turbine converts thermal energy into mechanical energy through a series of stages that capture the momentum from the expanding steam. These impulses and reactions are used to drive the shaft, which is connected to the generator to produce electricity.

The steam turbine is equipped with **uncontrolled extraction** of steam with pressure of 0.7 bar and temperature of 110°C for DH purposes. This higher-pressure steam from uncontrolled extraction, together with **backpressure outlet steam** of 0.3 bar and 65°C, is used for heat supply of two DHS heat exchangers.

All condensed steam from the network water heaters and feedwater preheater is collected in feedwater tank which is supplemented with demineralized water as needed to compensate for water losses in the system (boiler blowdown, sludge removal and condensate loss from process steam). The feedwater tank is equipped with a deaerator which is supplied with low pressure steam. After exiting the deaerator, two feedwater pumps, one for high and one for low pressure in boiler) increase the pressure of the feedwater which then enters the HRGS, completing the cycle and initiating a new one.

After two heat exchangers which use steam from the steam turbine, DH flow water is additionally heated with remaining heat from gas turbine exhaust gasses residual heat, left after two stages of HRSB, through the dedicated heat exchanger loop. Also, in a DH loop, there is a dry cooling tower enables additional cooling of DH return water to enable electricity production during periods of low thermal demand, mainly in summer period.

Overall technical characteristics of CHP (type 1) configuration is given in following table:

Table 6-5. Technical characteristics of the gas turbine unit in combined cycle cogeneration

GAS TURBINE AGGREGATE	Unit	CHP (type 1)
Manufacturer of gas turbine		Siemens
Gas turbine model		SGT-800
Type of turbine		Heavy-duty gas turbine
Number of gas turbines	-	2
Gross power output in simple cycle (per turbine)	MW	62.5
Efficiency (simple cycle)	%	41.1
Heat rate	kJ/kWh	8,759[2]
Pressure ratio	-	21.1:1

GAS TURBINE AGGREGATE	Unit	CHP (type 1)
NOx Emission (@ 15% O2)	ppm	15 – 25 ppmvd
Exhaust temperature	°C	596
Exhaust mass flow	kg/s	135.5
Maximum electric power in the combi cycle (overall CHP plant)	MW	170
Heat output (overall CHP plant)	MW	116
Efficiency (in the combi cycle)	%	87.6
Compressor power (6-30 bar)	MW	2,37

[1] Gross heat rate

The maximum electrical output of the analysed system is **164 MWe** and maximum thermal output of the system is **120 MWt**, with an efficiency of energy transformation of **87.6 %**. Simple cycle efficiency of the gas turbine is 41.1%.

Connection points within the scope of construction of a new block

Fitting the new block into the existing system of the CHP Source 1 at the operational level implies defining the connection points of the new block system to the existing systems of the CHP Source 1, as well as the eventual reconstruction of individual existing systems or their parts.

The points of connection within the scope of the construction are elaborated in the following paragraphs.

- Natural gas system

This point is elaborated in paragraph 6.2.1.2 for all the alternatives of CHP.

- Feed water preparation system

A new unit will be connected to the newly constructed chemical treatment section, as the existing one is worn out after over 40 years of operation, with degraded concrete structures.), whereby the chemically prepared water is fed into the feed water tank as part of the deaerator. In this context, it is necessary to create a connected pipeline from the chemical water treatment station to the supply tank of the new block.

- Waste and oily water system

The waste and oily water system must be connected to the existing wastewater system.

- Connection to the power grid of **CHP - type 1 [2 x SGT800 + 2 x HRSB + ST]**

For connection of alternative A of new CHP, type 1 are proposed three different options: (1) radial connection, (2) double links connection and (3) radial/block connection. While option 1 is the cheapest solution and has smallest space requirements, it has lower reliability of operation. Option 3 solution is the most reliable because of redundant links but implies highest cost and largest space. Option 2 connection has medium cost and lower reliability. All three options consider cable/s with length of approx. 0.4 km connected to 110 kV outdoor switchgear (bay) at the existing substation SS CHP Source 1, see Figure 6-14. Ampacity of the cable/s shall be compatible with installed power of the units/plant (170 MW) - it is recommended to use single-pole aluminium conductor cables with cross-linked polyethylene insulation, (XLPE Al 1600 mm^2) that has rated power higher than 180 MVA. In case of option 3 where each unit has direct radial block (step-up transformer + cable) connection, cables should have smaller ampacity of about 80 MVA (XLPE Al-300 mm^2) due to nominal

rating of the unit. The number of single-pole cables are different for all three options, please refer to heading "Connection to the power grid" on this section for more details.

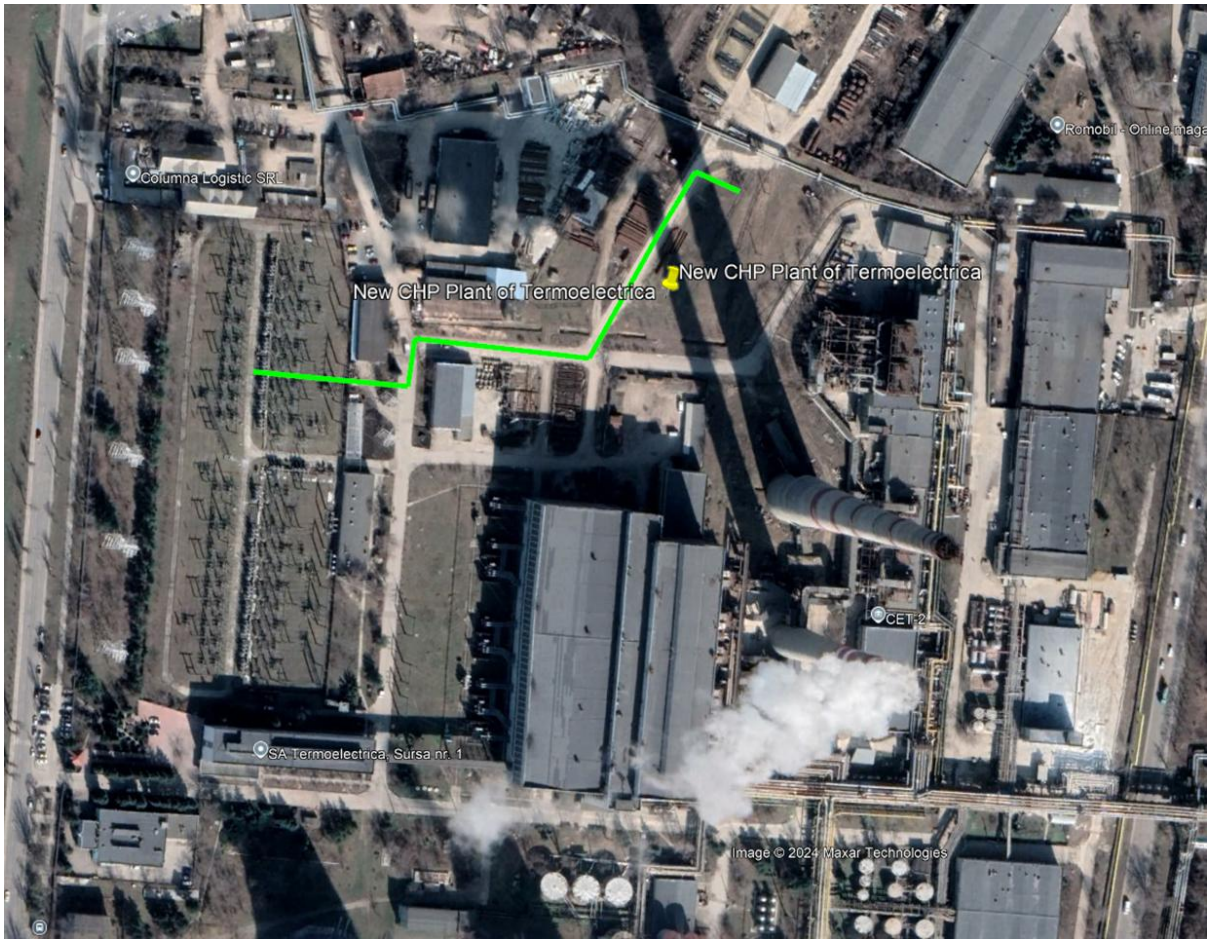


Figure 6-14. Grid connection of new CHP configuration type 1, 2, 4 and 5

- Connection to DHS

The connection of the new unit to the system for heating of DHS water will be carried out in parallel with the existing exchangers of the existing CHP blocks at CHP Source 1, as it is shown in Figure 6-21. Connection to DHS. In this context, it will be necessary to carry out an appropriate reconstruction of the system, because the pipes are relatively large dimensions, the placement of which can represent a certain problem.

6.2.1.2.2 CHP (type 2) [3 × SGT800 + 3 × HRSB + ST]

The new configuration of the CHP unit, as depicted in the accompanying figure (Figure 6-15), closely resembles the previous design. The key difference is the addition of an **extra gas turbine as well as HRSB**, which enables the generation of additional electricity and steam. The integration of the third gas turbine increases the total electrical generation capacity enabling the system to meet higher demand profiles with greater flexibility. Furthermore, the additional turbine's exhaust gases contribute to an increased volume of available thermal energy which is captured by an **expanded set of Heat Recovery Steam Boilers** (HRSBs).

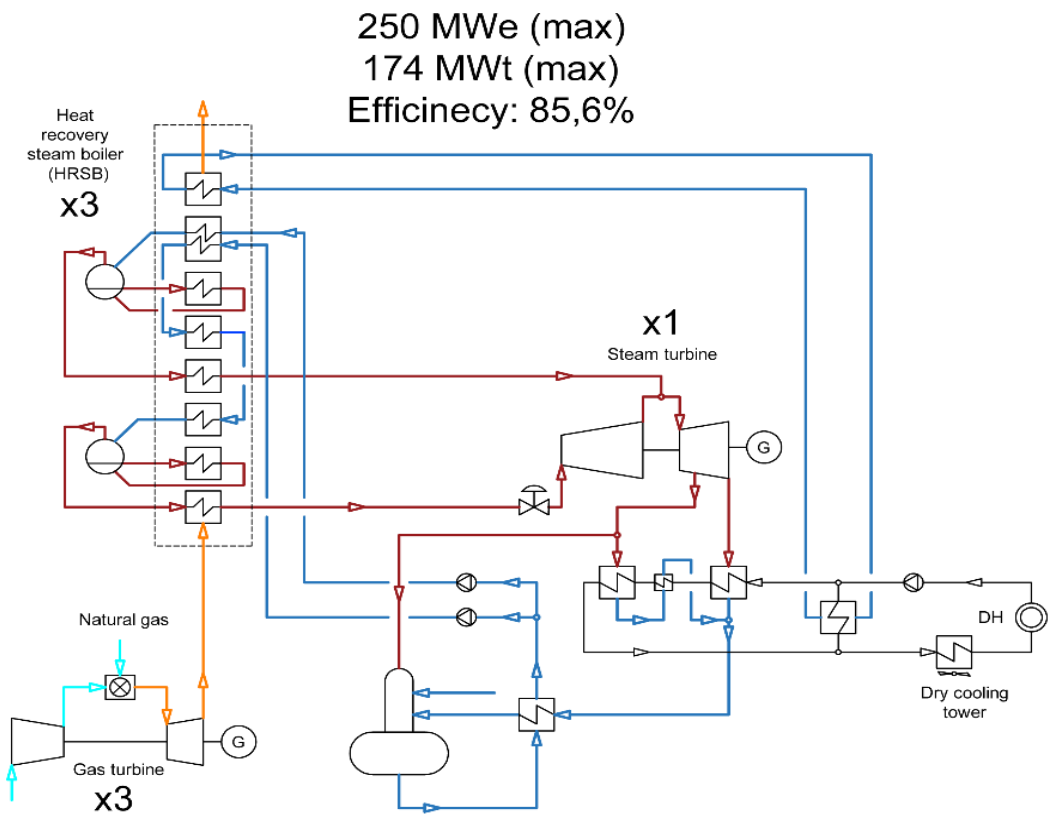


Figure 6-15. Combined cycle CHP configuration type 2 [3 x SGT800 + 3 x HRSB + ST]

This cogeneration system features a 3x1 configuration with three Siemens SGT-800 gas turbines (one more than in previous case), three dual pressure heat recovery steam boilers (HRSBs), and one backpressure steam turbine.

The considered gas turbine, Siemens SGT-800 gas turbine, is a high-efficiency industrial gas turbine renowned for its reliability, operational flexibility, and low emissions. The single-shaft engine of Siemens SGT-800 turbine is composed of a 2-bearing rotor with a 15-stage compressor and a 3-stage turbine.

The combustion of natural gas in gas turbines produces exhaust gases which are routed from the turbine diffuser into two dual pressure HRSBs where it exchanges heat with feedwater. One part of feedwater flows into the high-pressure section where it is converted into dry saturated steam which is further heated in the superheater to 520°C and 95 bar which are required operating parameters in the high-pressure section of the steam turbine. The rest of the water is preheated and flows into the low-pressure section where the dry saturated steam is separated and heated to 200°C and 7 bar which are parameters necessary for injection into the low-pressure section of the steam turbine.

The turbine steam path inside steam turbine converts thermal energy into mechanical energy through a series of stages that capture the momentum from the expanding steam. These impulses and reactions are used to drive the shaft, which is connected to the generator to produce electricity.

The steam turbine is equipped with **uncontrolled extraction** of steam with pressure of 0.7 bar and temperature of 110°C for DH purposes. This higher-pressure steam from uncontrolled extraction,

together with **backpressure outlet steam** of 0.3 bar and 65°C, is used for heat supply of two DHS heat exchangers.

All condensed steam from the network water heaters and feedwater preheater is collected in feedwater tank which is supplemented with demineralized water as needed to compensate for water losses in the system (boiler blowdown, sludge removal and condensate loss from process steam). The feedwater tank is equipped with a deaerator which is supplied with low pressure steam. After exiting the deaerator, two feedwater pumps, one for high and one for low pressure in boiler) increase the pressure of the feedwater which then enters the HRGS, completing the cycle and initiating a new one.

After two heat exchangers which use steam from the steam turbine, DH flow water is additionally heated with remaining heat from gas turbine exhaust gasses residual heat, left after two stages of HRSB, through the dedicated heat exchanger loop. Also, in a DH loop, there is a dry cooling tower enables additional cooling of DH return water to enable electricity production during periods of low thermal demand, mainly in summer period.

Overall technical characteristics of CHP (type 2) configuration is given in following table:

Table 6-6. Technical characteristics of the gas turbine unit in combined cycle cogeneration

GAS TURBINE AGGREGATE	Unit	CHP (type 2)
Manufacturer of gas turbine		Siemens
Gas turbine model		SGT-800
Type of turbine		Heavy-duty gas turbine
Number of gas turbines	-	3
Gross power output in simple cycle (per turbine)	MW	62.5
Efficiency (simple cycle)	%	41.1
Heat rate	kJ/kWh	8,759[2]
Pressure ratio	-	21.1:1
NOx Emission (@ 15% O2)	ppm	15 – 25 ppmvd
Exhaust temperature	°C	596
Exhaust mass flow	kg/s	135.5
Maximum electric power in the combi cycle (overall CHP plant)	MW	250
Heat output (overall CHP plant)	MW	174
Efficiency (in the combi cycle)	%	87.6
Compressor power (6-30 bar)	MW	3,65

[1] Gross heat rate

The maximum electrical output of the system is **246 MWe** and maximum thermal output of the system is **180 MWt**, with an efficiency of energy transformation of **87.6**%.

Connection points within the scope of construction of a new block

Fitting the new block into the existing system of the CHP Source 1 at the operational level implies defining the connection points of the new block system to the existing systems of the CHP Source 1, as well as the eventual reconstruction of individual existing systems or their parts.

The points of connection within the scope of the construction of a new block are presented in the following paragraphs.

- Natural gas system

This point is elaborated in paragraph 6.2.1.2 for all the alternatives of CHP.

- Feed water preparation system

A new unit will be connected to the newly constructed chemical treatment section, as the existing one is worn out after over 40 years of operation, with degraded concrete structures.), whereby the chemically prepared water is fed into the feed water tank as part of the deaerator. In this context, it is necessary to create a connected pipeline from the chemical water treatment station to the supply tank of the new block.

- Waste and oily water system

The waste and oily water system must be connected to the existing wastewater system.

- Connection to the power grid of **CHP - type 2 [3 x SGT800 + 3 x HRSB + ST]**

For connection of alternative B of new CHP, type 2 are proposed three different options: (1) radial connection, (2) double links connection and (3) radial/block connection. While option 1 is the cheapest solution and has smallest space requirements, it has lower reliability of operation. Option 3 solution is the most reliable because of redundant links but implies highest cost and largest space. Option 2 connection has medium cost and lower reliability. All three options consider cables with length of approx. 0.4 km connected to 110 kV outdoor switchgear (bay) at the existing substation SS CHP Source 1, see Figure 6-14. Ampacity of the cables shall be compatible with installed power of the plant (250 MW) - it is recommended to use single-pole copper conductor cable with cross-linked polyethylene insulation, (XLPE Cu 2000 mm^2) that has rated power higher than 265 MVA. In case of option 3 where each unit has direct radial block (step-up transformer + cable) connection, cables should have smaller ampacity of about 80 MVA (XLPE Al-300 mm^2) due to nominal rating of the unit. The number of single-pole cables are different for all three options, please refer to heading "Connection to the power grid" on this section for more details.

6.2.1.2.3 CHP (type 3) [GT 9F.04 + 1 x HRSB + ST]

This configuration of the CHP unit, as depicted in the accompanying image (Figure 6-16), also closely resembles the previous designs. It includes one more powerful gas turbine compared to the more smaller gas turbines in the previous configurations, enabling greater electricity and steam production while simultaneously achieving higher overall efficiency. Drawback of this approach is decreased flexibility of operation.

This cogeneration system features a **1x1 configuration with one gas turbine** coupled with **one dual pressure heat recovery steam boiler** (HRSB) and **one backpressure steam turbine**.

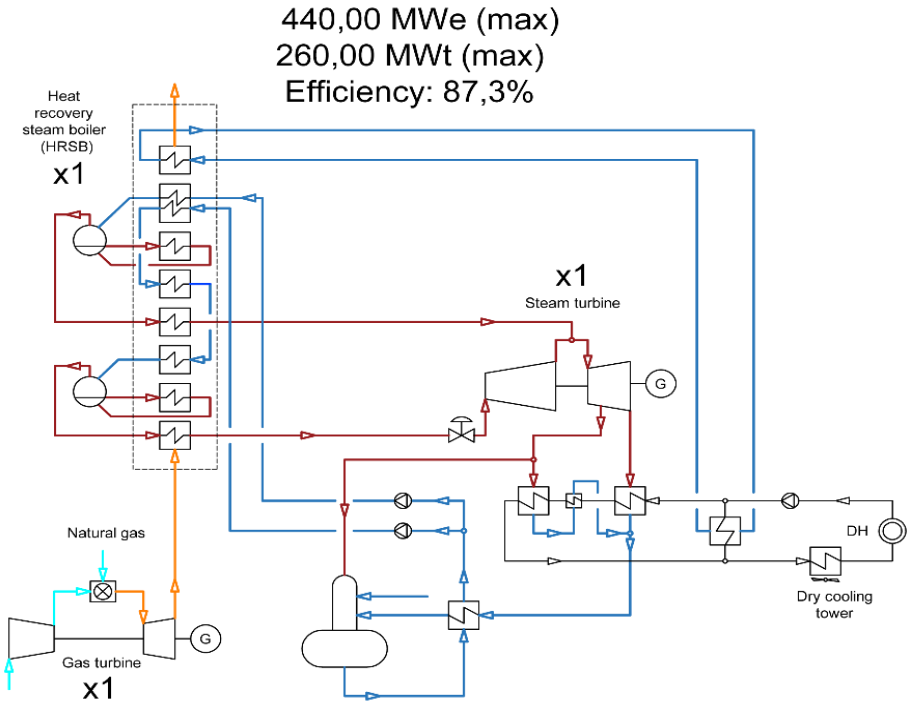


Figure 6-16. Combined cycle CHP configuration type 3 [1 x GE 9F.04 + 1 x HRSB + ST]

The following table (Table 6-7) shows the main characteristics of the considered gas turbine in this study and possible alternative in this power range.

Table 6-7. Considered and alternative gas turbines for CHP type 3 technical solutions

	Unit	GE 9F.04	Siemens SGT5-4000F	MHPS M701G	AE 94.3A
Manufacturer	-	GE Vernova	Siemens Energy	Mitsubishi-Hitatchi	Ansaldo Energia
Model	-	9F.04	SGT5-4000F	M701G	AE94.3A
Country of Origin	-	France	Sweden	Japan	Italy
Electrical output (ISO)	MW	288	329	330	340
Efficiency (open cycle)	%	38.7	41.0	39.5	40.3
NOx Emission (@15% O2)	ppm	15	15	25	15

GE 9F gas turbine delivers consistent performance and accommodates a diverse range of fuels, making it great for a variety of combined cycle and CHP applications. With over 450 units deployed to more than 40 countries, GE F class turbines are established as the clear industry leader. It includes 18-stage axial compressor and a three-stage turbine on a single shaft, and features a cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements.

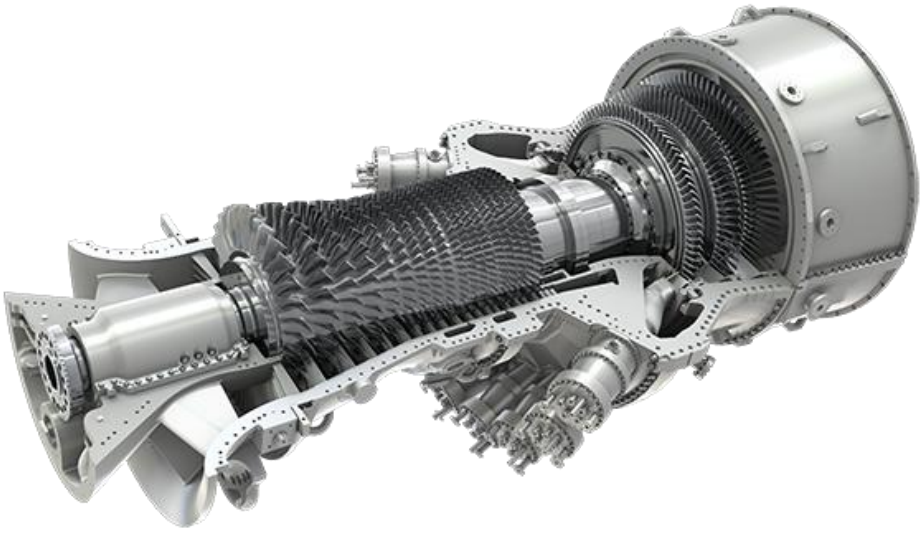


Figure 6-17. 3D view of GE 9F.04 gas turbine

GE 9F.04 is particularly well-suited for combined cycle and CHP applications due to its high electrical efficiency and excellent steam-raising capability. SGT-800 gas turbine has a power output of 288 MWe, net electrical efficiency of 38.7% respectively, and net heat rate of 9295 kj/kWh (LHV) in simple cycle power generation.

The GE 9F.04 offers excellent fuel flexibility and also has the ability to operate with approximately 30% premixed hydrogen volume content in dry mode enabling transition to the use of sustainable fuels. The ability of gas turbine to operate on a high hydrogen fuel requires a combustion system that can deal with the specific nature of this fuel. Through the use of the single nozzle or multi-nozzle quiet combustor (MNQC) diffusion combustion of up to 100% of hydrogen can be achieved. This leads to very high flame temperatures as well as high NOx emissions which can be mitigated through the use of diluent such as water, steam, or nitrogen injected into the combustor to reduce NOx emissions.

The combustion of natural gas in gas turbines produces exhaust gases which are routed from the turbine diffuser into dual pressure HRSBs where it exchanges heat with feedwater. One part of feedwater flows into the high-pressure section where it is converted into dry saturated steam which is further heated in the superheater to 520°C and 95 bar which are required operating parameters in the high-pressure section of the steam turbine. The rest of the water is preheated and flows into the low-pressure section where the dry saturated steam is separated and heated to 200°C and 7 bar which are parameters necessary for injection into the low-pressure section of the steam turbine.

The turbine steam path inside steam turbine converts thermal energy into mechanical energy through a series of stages that capture the momentum from the expanding steam. These impulses and reactions are used to drive the shaft, which is connected to the generator to produce electricity.

The steam turbine is equipped with **uncontrolled extraction** of steam with pressure of 0.7 bar and temperature of 110°C for DH purposes. This higher-pressure steam from uncontrolled extraction, together with **backpressure outlet steam** of 0.3 bar and 65°C, is used for heat supply of two DHS heat exchangers.

All condensed steam from the network water heaters and feedwater preheater is collected in feedwater tank which is supplemented with demineralized water as needed to compensate for water losses in the system (boiler blowdown, sludge removal and condensate loss from process steam). The feedwater tank is equipped with a deaerator which is supplied with low pressure steam. After exiting the deaerator, two feedwater pumps, one for high and one for low pressure in boiler) increase the pressure of the feedwater which then enters the HRGB, completing the cycle and initiating a new one.

After two heat exchangers which use steam from the steam turbine, DH flow water is additionally heated with remaining heat from gas turbine exhaust gasses residual heat, left after two stages of HRSB, through the dedicated heat exchanger loop. Also, in a DH loop, there is a dry cooling tower enables additional cooling of DH return water to enable electricity production during periods of low thermal demand, mainly in summer period.

Overall technical characteristics of CHP (type 3) configuration is given in following table:

Table 6-8. Technical characteristics of the gas turbine unit in combined cycle cogeneration

GAS TURBINE AGGREGATE	Unit	CHP (type 3)
Manufacturer of gas turbine		General Electric
Gas turbine model		9F.04
Type of turbine		Heavy-duty gas turbine
Number of gas turbines	-	1
Gross power output in simple cycle (per turbine)	MW	288
Efficiency (simple cycle)	%	38.7
Heat rate	kJ/kWh	9295[1]
Pressure ratio	-	16.8:1
NOx Emission (@ 15% O2)	ppm	15
Exhaust temperature	°C	608
Exhaust mass flow	kg/s	n/a
Maximum electric power in the combi cycle (overall CHP plant)	MW	440
Heat output (overall CHP plant)	MW	260
Efficiency (in the combi cycle)	%	89.1
Compressor power (6-50 bar)	MW	7,72

[1] Net heat rate

The maximum electrical output of the system is **440 MWe** and maximum thermal output of the system is **260 MWt**, with an efficiency of energy transformation of **89.1%**.

Connection points within the scope of construction of a new block

Fitting the new block into the existing system of the CHP Source 1 at the operational level implies defining the connection points of the new block system to the existing systems of the CHP Source 1, as well as the eventual reconstruction of individual existing systems or their parts.

The points of connection within the scope of the construction of a new block are presented in the following paragraphs.

- Natural gas system

This point is elaborated in paragraph 6.2.1.2 for all the alternatives of CHP.

- Feed water preparation system

The new block is connected to the existing feed water preparation system (it does not have its own system), whereby the chemically prepared water is fed into the feed water tank as part of the deaerator. In this context, it is necessary to create a connected pipeline from the chemical water treatment station to the supply tank of the new block.

- Waste and oily water system

The waste and oily water system must be connected to the existing wastewater system.

- Connection to the power grid of **CHP - type 3 [1 x GE 9F.04 + 1 x HRSB + ST]**

For connection of alternative C of new CHP, type 3 are proposed three different options: (1) radial connection, (2) double links connection and (3) radial/block connection. While option 1 is the cheapest solution and has smallest space requirements, it has lower reliability of operation. Option 3 solution is the most reliable because of redundant links but implies highest cost and largest space. All three options consider 330 kV hybrid line. Line will end-up to 330 kV outdoor switchgear (bay) at the existing substation 330/110/35 kV SS Chisinau. Hybrid Line will comprise overhead section and cable section, see Figure 6-18. Urban area shall be crossed by underground cable, while open space could be passed by overhead line.

Ampacity of the hybrid line shall be compatible with installed power of the plant (440 MW) - it is recommended to use ACSR ACO-500 mm2 conductor for overhead line with rating of about 550 MVA and use single-pole aluminium conductor cable with cross-linked polyethylene insulation, (XLPE Al 1600 mm^2) that has the same rated power of about 550 MVA. The number of single-pole cables are different for all three options, please refer to heading "Connection to the power grid" on this section for more details.

Two different routes have been considered. The yellow route is shorter, with 8.5 km of overhead line and 11 km of underground cable, about 19 km in total. The blue route is longer, with 3 km of overhead line and 38.5 km of underground cable, about 42 km in total. However, the routing of the connection could potentially confront a lot of urban barriers because of densely populated area and will be challenging for permitting and construction.

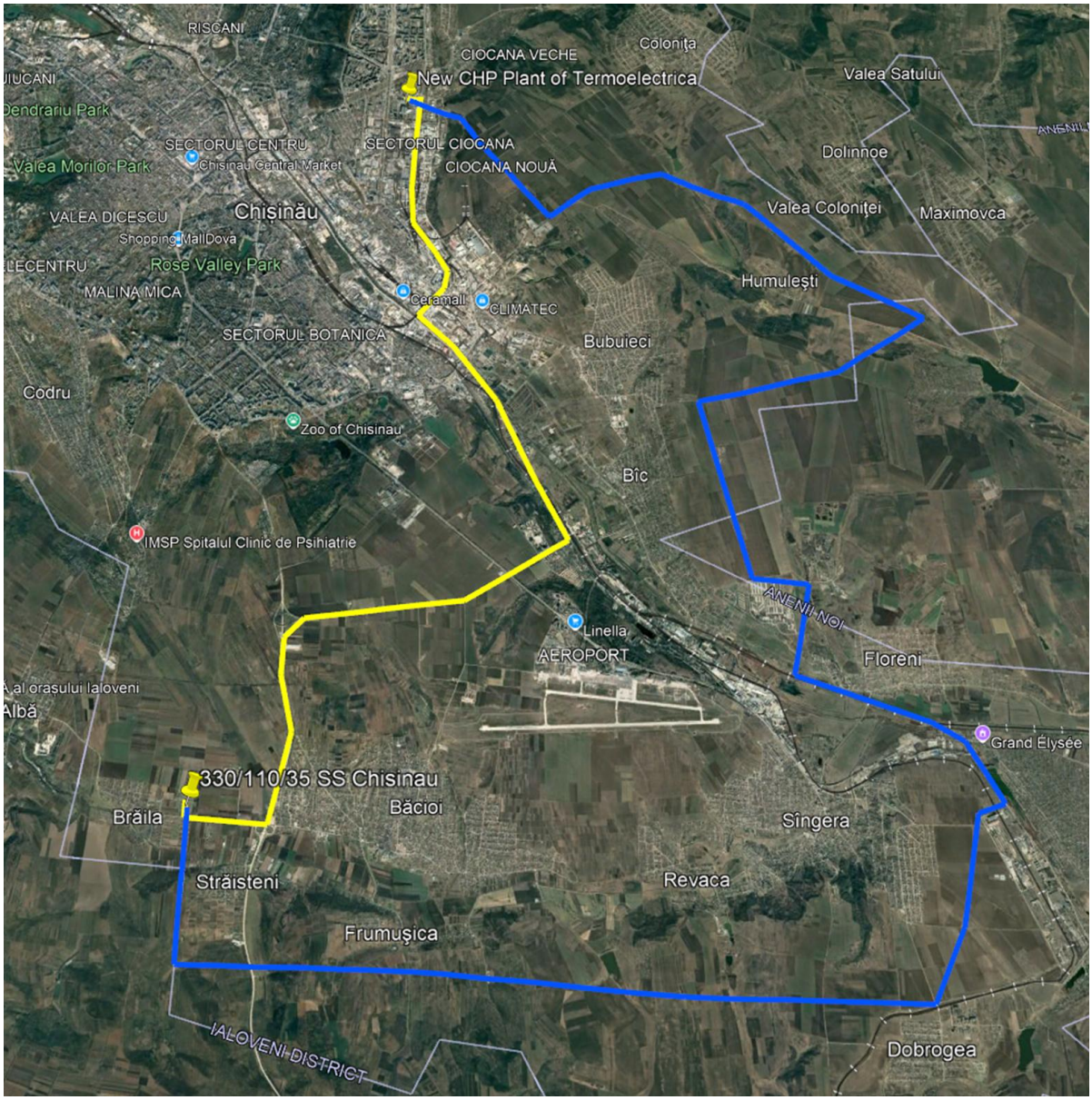


Figure 6-18. Grid connection of new CHP configuration type 3

6.2.1.3 Gas turbine with heat recovery boiler

Second type of possible options of new energy source is cogeneration system which also features a **gas turbines**, but the energy from exhaust gasses is recovered in **Heat Recovery Boiler (HRBs)** and directly supplies the heating demand, eliminating the need for a backpressure steam turbine. This way system complexity is decreased, as well as space requirements and installation time, response time is also decreased and flexibility of operation is increased, but at the same time, by elimination of steam turbine, electricity and heat production ratio is decreased in the favour of heat production.

To further build upon the system strong sides, Aeroderivative gas turbine is used. They are developed for installation in small spaces, they are small in weight and have modular design. They have the ability to be put into operation very quickly and quick ramp up to nominal power with little

consequences due to dynamic stresses. They are designed for simple and quick moving and maneuvering, which enables quick installation, efficient maintenance and considerably shortens downtime and increases flexibility and working time.

In this case, in gas turbine, natural gas is mixed with compressed air and burned in the combustion chamber. Then the gases - products of combustion, move the rotor blades of the gas turbine, so the power is transmitted via the common shaft to the rotor of the electricity generator. The thermal energy of the flue gases is used in the HRs for covering energy needs of district heating system.

HRHG consists of a series of heat exchangers where each heat exchanger comprises a bundle of tubes, which can be arranged either in-line or staggered, depending on the manufacturer's design specifications. The working fluid (water) usually flows horizontally through these tubes, while the exhaust gases flow vertically across them. Due to the relatively low heat transfer coefficients on the side of exhaust gases from the turbine compared to those of the working fluid in the evaporator and economizer, finned tubes are utilized to enhance heat transfer on the gas side. The fins can be either solid or serrated, selected based on performance requirements and manufacturing considerations.

In the following subchapter, considered system configuration, which will be used in scenario development, is further analysed.

6.2.1.3.1 CHP (type 4) [3 × GT LM6000 + 3 × HRB]

Considered system configuration utilizes a **3x1 configuration with gas turbines** in a **simple cycle** arrangement and **three Heat Recovery Boiler** (HRBs).

Combustion of natural gas in the gas turbine produces flue gases. When there is no demand for thermal energy, these gases are released into the atmosphere. Otherwise, they pass through the Heat Recovery Boiler (HRBs), where a series of heat exchangers transfer the heat to the feedwater used for delivering heat for district heating purposes.

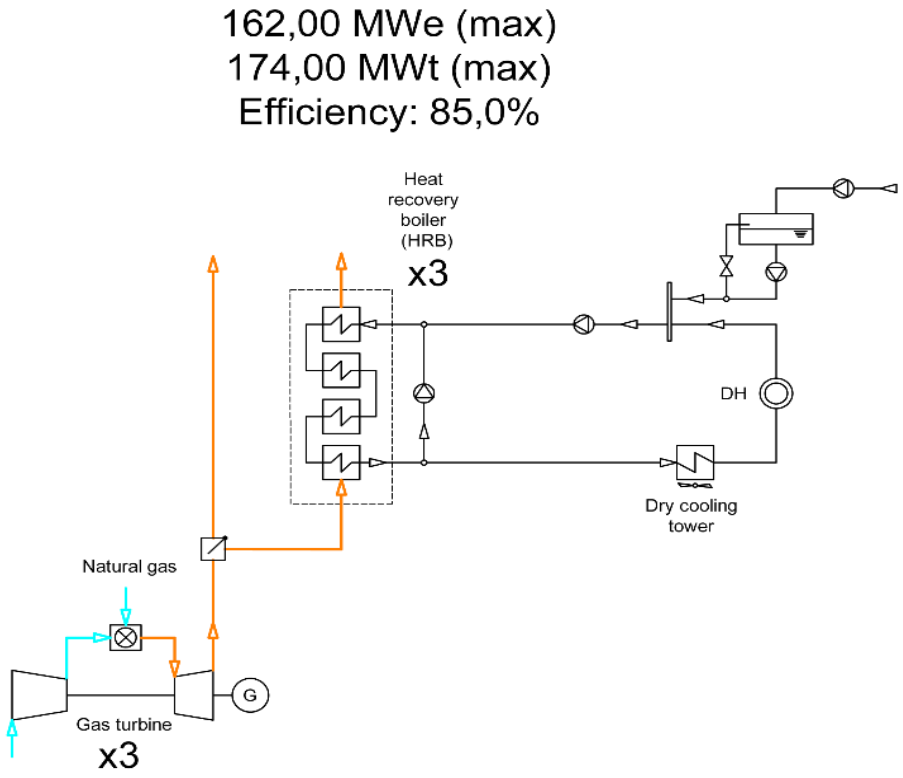


Figure 6-19. Gas turbine with heat recovery boiler CHP configuration [3 x GE-LM6000 + 3 x HRB]

The following table (Table 6-9) shows the main characteristics of the considered gas turbine in this study and possible alternative in this power range.

Table 6-9. Considered and alternative gas turbines for CHP type 3 technical solutions

	Unit	GE LM6000 PF+	Siemens SGT-A35
Manufacturer	-	GE Vernova	Siemens Energy
Model	-	LM6000PF+	SGT-A35
Country of Origin	-	France	Sweden
Electrical output (ISO)	MW	53.9	38.1
Efficiency (open cycle)	%	40.8	40.5
NOx Emission (@15% O2)	ppm	15	15-25

GE LM6000 gas turbine is an aeroderivative gas turbine with the most operating experience than in its power range offering better efficiency and lower start-up time compared to heavy frame industrial gas turbines. It includes five-stage low-pressure compressor (LPC), a 14-stage high-pressure compressor (HPC), an annular combustor, a two-stage high-pressure turbine (HPT), and a five-stage low-pressure turbine (LPT).

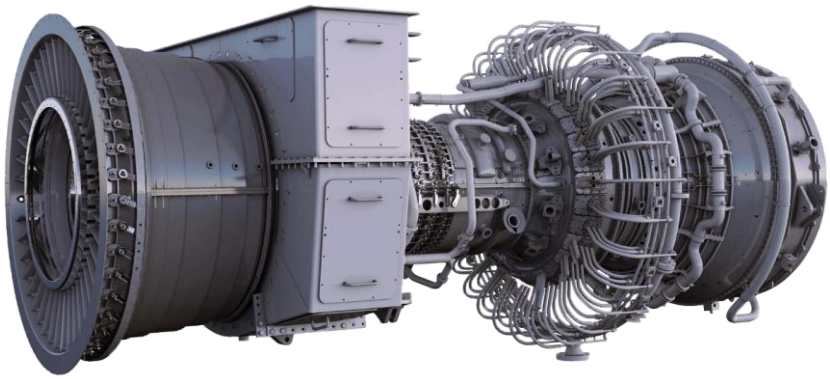


Figure 6-20. 3D view of GM LM6000 gas turbine

LM6000 is well-suited for simple and combined cycle configurations as well as dry or wet combustor configuration. Used model LM6000 PF+ has a power output of 53.9MWe, net 40.8% in simple cycle power generation, and net heat rate of 8817 kj/kWh (LHV) in simple cycle power generation.

With integration of SPRINT solution engine performance can be boosted using a spray intercooling design that increases the mass flow by cooling the air during the compression process. The system is based on an atomized water spray injected through spray nozzles which use increase net power output to 57.1 MWe.

The LM6000 allows operation on a wide variety of fuels – including natural gas, LPG (propane and butane), isopentane, ethanol, diesel, Coke Oven gas, and hydrogen. Even though by using premixing it can handle up to 20% of volume chare of hydrogen, through the use of single annular combustor (SAC) operation the LM6000 is 100% hydrogen capable.

The combustion of natural gas in gas turbines produces exhaust gases which are routed from the turbine diffuser into dual pressure HRBs which directly cover district heating energy needs.

Overall technical characteristics of CHP (type 4) configuration is given in following table:

Table 6-10. Technical characteristics of the gas turbine unit in open cycle cogeneration power plant

GAS TURBINE AGGREGATE	Unit	CHP (type 4)
Manufacturer of gas turbine		General Electric
Gas turbine model		LM6000 PF+
Type of turbine		Aeroderivative gas turbine
Number of gas turbines	-	3
Gross power output in simple cycle (per turbine)	MW	53.9
Electrical Efficiency (simple cycle)	%	40.8
Heat rate	kJ/kWh	8817[1]
Pressure ratio	-	28.0:1
NOx Emission (@ 15% O2)	ppm	15
Exhaust temperature	°C	498
Exhaust mass flow	kg/s	139.4
Maximum electric power in the combi cycle (overall CHP plant)	MW	162
Heat output (overall CHP plant)	MW	174
Overall Efficiency	%	85

Compressor power (6-30 bar)	MW	2,9

[1] Net heat rate

The maximum electrical output of this system is 162.0 MWe and maximum thermal output of the system is 174.0 MWt, with efficiency of energy transformation of 85.0%

Connection points within the scope of construction of a new block

Fitting the new block into the existing system of the CHP Source 1 at the operational level implies defining the connection points of the new block system to the existing systems of the CHP Source 1, as well as the eventual reconstruction of individual existing systems or their parts.

The points of connection within the scope of the construction of a new block are:

- Natural gas system

This point is elaborated in paragraph 4.2.1.2 for all the alternatives of CHP.

- Feed water preparation system

A new unit will be connected to the newly constructed chemical treatment section, as the existing one is worn out after over 40 years of operation, with degraded concrete structures.), whereby the chemically prepared water is fed into the feed water tank as part of the deaerator. In this context, it is necessary to create a connected pipeline from the chemical water treatment station to the supply tank of the new block.

- Waste and oily water system

The waste and oily water system must be connected to the existing wastewater system.

- Connection to the power grid **CHP - type 4 [3 × GT LM6000 + 3 × HRB]**

For connection of alternative D of new CHP, type 4 1 are proposed three different options: (1) radial connection, (2) double links connection and (3) radial/block connection. While option 1 is the cheapest solution and has smallest space requirements, it has lower reliability of operation. Option 2 solution is the most reliable because of redundant links but implies highest cost and largest space. Option 3 connection has medium cost and lower reliability. All three options consider cable/s with length of approx. 0.4 km and connected to 110 kV outdoor switchgear (bay) at the existing substation SS CHP Source 1, see Figure 6-14. Ampacity of the cable shall be compatible with installed power of the units/plant (162 MW) - it is recommended to use single-pole aluminium conductor cable with cross-linked polyethylene insulation, (XLPE Al 1600 mm^2) that has rated power higher than 180 MVA. In case of option 3 where each unit has direct radial block (step-up transformer + cable) connection, cables should have smaller ampacity of about 80 MVA (XLPE Al-300 mm^2) due to nominal rating of the unit. The number of single-pole cables are different for all three options, please refer to heading "Connection to the power grid" on section 6.2.1.2 for more details.

- Connection to DHS

The connection of the new unit to the system for heating of DHS water will be carried out in parallel with the existing exchangers of the existing CHP blocks at CHP Source 1, as it is shown in Figure 6-21. Connection to DHS. In this context, it will be necessary to carry out an appropriate reconstruction of the system, because the pipes are relatively large dimensions, the placement of which can represent a certain problem.

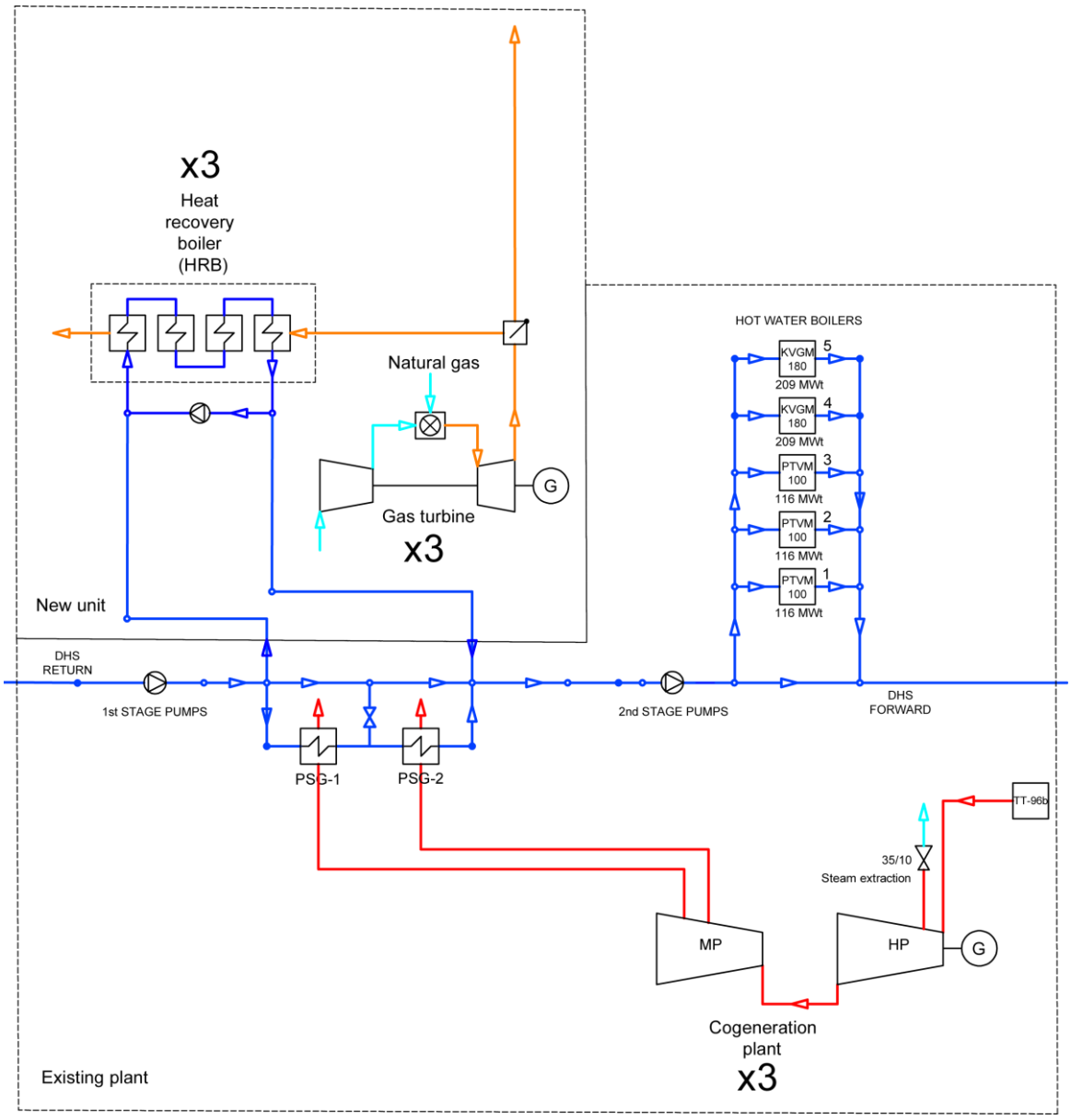


Figure 6-21. Connection to DHS

6.2.1.4 CHP gas engines

This power generation system leverages a **fleet of gas engine CHPs**. Gas engine-driven units consist of an **internal combustion engine** (ICE), a **generator**, a **clutch**, a common base and **supporting structure**. Typically, the engine and generator are firmly mounted on a common base. Components can be added to the basic configuration to create a cogeneration unit that serves to produce electricity and heat. Additional components are:

1. waste heat exchanger,
2. engine cooler,
3. engine oil coolers,

4. intercoolers for compressed air,
5. silencers,
6. flue gas cleaning system,
7. fuel tank or gas station,
8. supply of engine oil,
9. monitoring system.

A cogeneration plant with gas engines consists of one or more cogeneration aggregates, electrical connections with a control system, an air supply system and an air exhaust system as shown in the figure below.

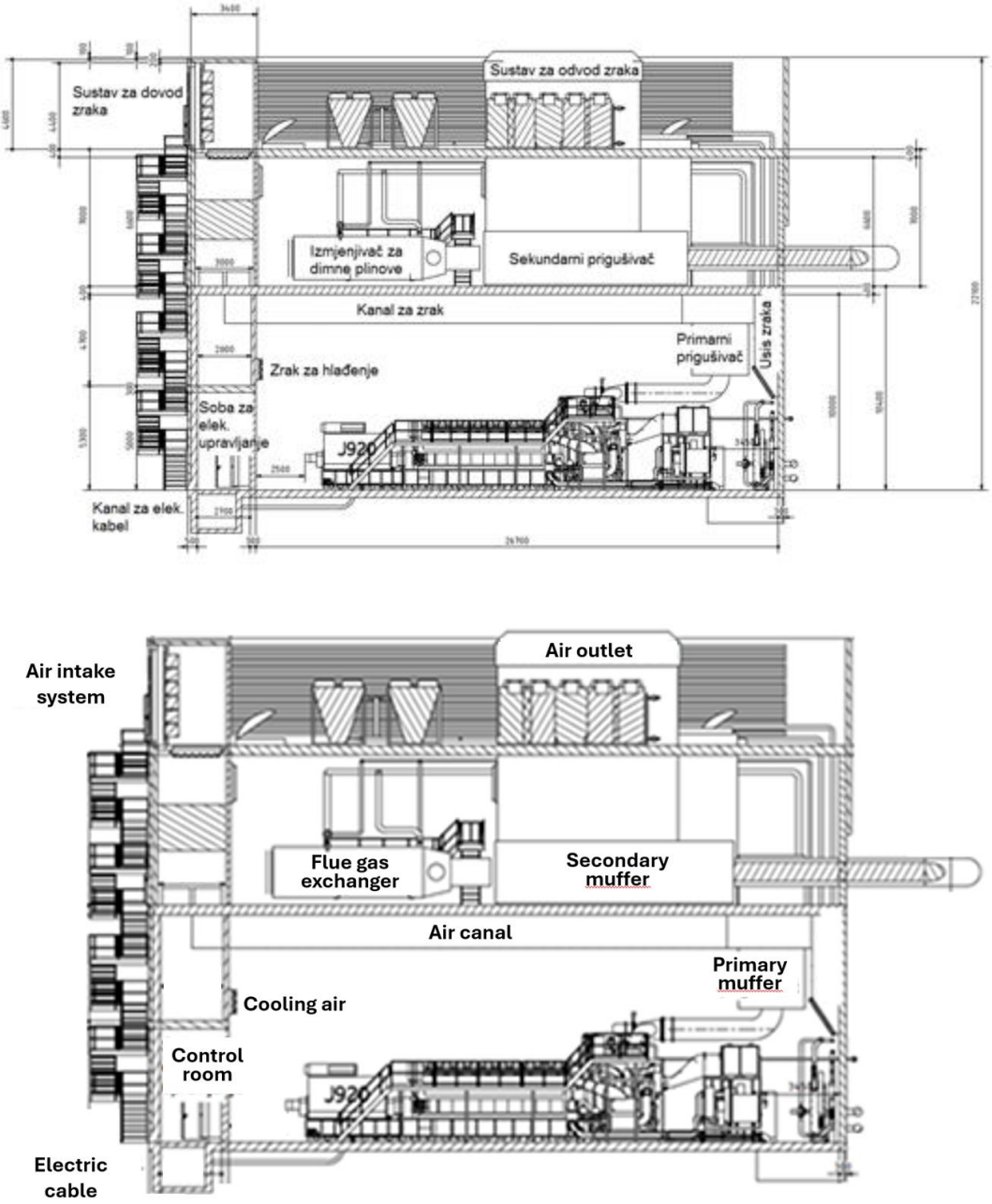


Figure 6-22. Gas engines CHP plant

In the considered system, power generation system leverages a fleet of up to 20 gas engine cogeneration units. The following table (Table 6-11) shows the main characteristics of the considered gas engine in this study and possible alternative in this power range. The data are presented at a load of 100% and a lower calorific value of the fuel of 9.5 kWh/mn3

Table 6-11. Considered and alternative gas engines

	Unit	Innio Jenbacher J920FleXtra*	MAN V51/60G TS
Manufacturer	-	Jenbacher, Austria	MAN Energy Solutions Germany
Speed	r/min	1.000	500
Frequency	Hz	50	50
Fuel consumption	kW	21.929	41.973
Mechanical power	kW	10.567	-
Electrical power	kW	10 387	20 220
Efficiency (for electric power generation)	%	47,4	48,2
Specific heat consumption	kJ/kWh	7.596	7.473
Air intercoolers	kW	3.716	-
Motor oil coolers	kW	1.194	-
Engine coolers	kW	1.171	-
Usable heat of flue gases	kW	4.103	-
Total usable heat	kW	10.185	17.892
Efficiency (for thermal energy)	%	46,4	42,6
Electric power + usable thermal power	kW	20.752	38.112
Overall efficiency	%	93,8	90,8

Aggregates with gas engines in cogeneration systems can meet various energy needs.

There are high performance heavy-duty gas engines / gensets from a number of manufacturers, including Innio Jenbacher, Bergen Engines, MAN Energy Solutions, Caterpillar, Wartsila, Hyundai.

Gas engines typically allow operation with a mixture of hydrogen and natural gas, with perspective of operation on hydrogen in the future.

Besides, in case liquid reserve fuel needs to be used (e.g. diesel), dual-fuel models (natural gas / diesel) are available from a several manufacturers, including MAN Energy Solutions, Wartsila, Hyundai. To be noted that in natural gas mode, dual-fuel engines need to use a small amount of diesel as pilot fuel.

In the following subchapters, considered system configuration, which will be used in scenario development, is further analysed.

6.2.1.4.1 CHP (type 5) [Gas engines Jenbacher J920FleXtra]

In this system combined energy of a fleet of up to **18 Jenbacher J920FleXtra gas engine CHPs** is utilised for covering heat and electricity demand. Each considered CHP engine can achieve a maximum electrical output of **10.7** megawatts electric power, contributing to a total gross potential electrical generation capacity exceeding **192 MWe** (depending on the number of engines). Regarding efficiency of power generation, it is 47,4%, but can change depending on operation regime and existence of the turbocharger. Notably, these engines also boast a maximum thermal output of 10.18 megawatts thermal (MWt) per unit, presenting a significant opportunity for waste heat recovery.

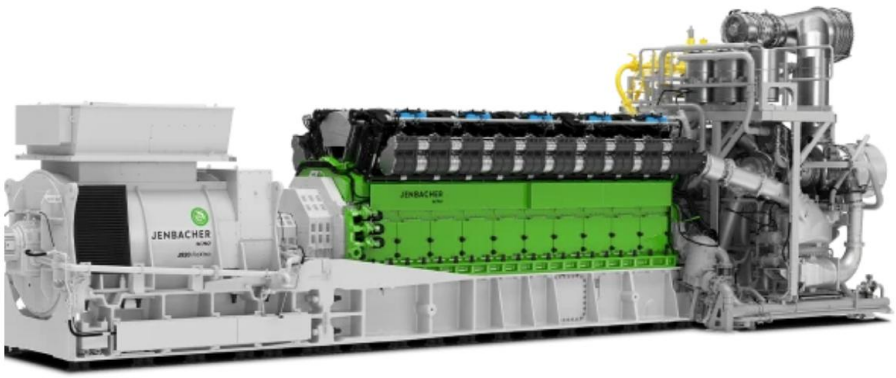


Figure 6-23. 3D view of Jenbacher J920FleXtra CHP gas engine

The considered configuration of the CHP unit with gas engines is shown in Figure 6-24. The process begins with the entry of natural gas into the gas engine which is a critical phase that affects the efficiency of the entire system. Natural gas is delivered through a pipeline system under controlled pressure to ensure a stable supply and prevent operational irregularities. Before entering the engine, the gas passes through a series of safety valves and pressure regulators to ensure the proper fuel quantity and optimal pressure for combustion. Simultaneously, air is drawn into the engine through an intake system equipped with an air filter to remove impurities and protect the internal components of the engine. The air-fuel mixture must be precisely balanced to achieve optimal combustion efficiency. In gas engines, this mixture is typically formed within the intake manifold or by direct injection of gas into the cylinders during the compression stroke. The air-fuel ratio is controlled by advanced engine management systems (ECU) which adjust to operating conditions, optimizing combustion and minimizing emissions.

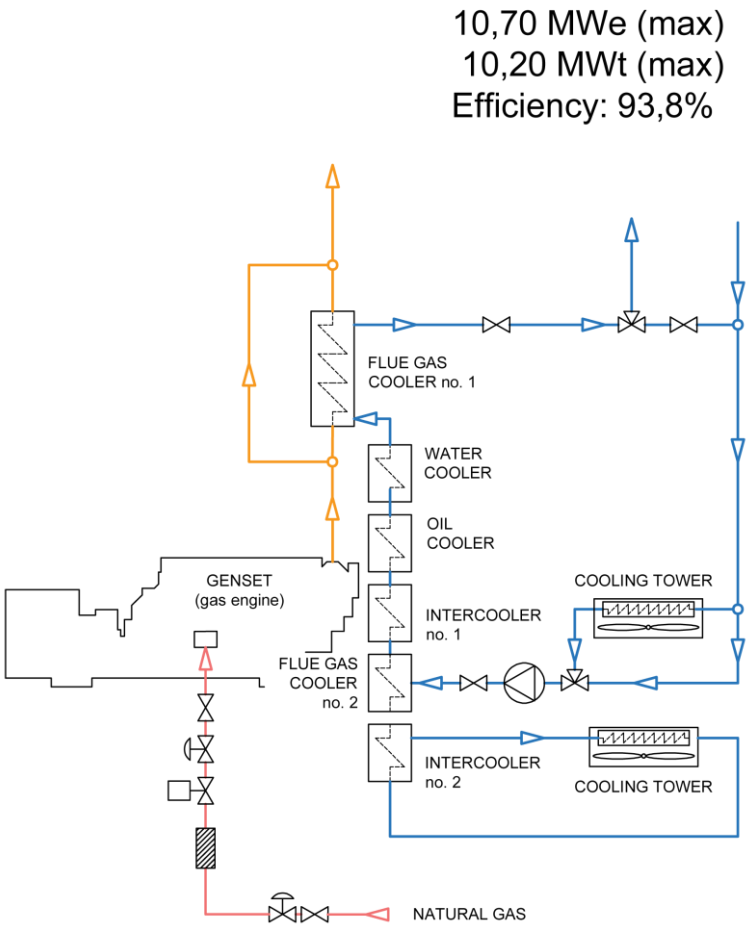


Figure 6-24. Gas engine CHP

Within the engine cylinder, the compressed air-fuel mixture is ignited by a spark plug that generates a spark. This spark initiates the combustion process where rapid expansion of gases occurs due to the release of thermal energy from the fuel. The combustion causes a sudden increase in pressure within the cylinder, pushing the piston downward in a powerful stroke known as the power stroke. The mechanical energy produced by this piston movement is transmitted to the crankshaft via the connecting rod, converting the linear motion into the rotational motion of the crankshaft. The rotation of the crankshaft drives the electric generator which converts mechanical energy into electrical energy. This electrical energy can be used locally in the plant or supplied to the electrical grid.

During combustion in the engine, residual heat remains in the exhaust gases and the engine's cooling system (water cooler, oil cooler and air cooler (intercooler)). In conventional setups, this heat would be released into the environment, but cogeneration plants efficiently repurpose this waste heat for further energy production. The exhaust gases, cooling water, oil and compressed air are routed through a heat exchanger where their thermal energy is transferred to the feedwater. The heated feedwater is then utilized for district heating, effectively supplying thermal energy to surrounding areas. Any remaining heat in the feedwater is directed to cooling towers, where it is dissipated, allowing the water to be cooled and recirculated. This closed-loop system of feedwater circulation ensures the engine operates efficiently by consistently removing excess heat, thus minimizing losses and maintaining high overall system performance.

Overall technical characteristics of CHP (type 5) configuration is given in following table:

Table 6-12. Technical characteristics of the CHP gas engines

GAS ENGINE	Unit	CHP (type 5)
Manufacturer of gas engine		Jenbacher
Gas engine model		J920 FleXtra
Number of gas engines	-	18
Maximum gross power output (per engine)	MW	10,7
Electricity generation efficiency	%	47,4
Heat rate	kJ/kWh	7.596
NOx Emission (@ 15% O2)	ppm	25
Maximum electric power (overall CHP plant)	MW	191,0
Heat output (overall CHP plant)	MW	185,0
Efficiency (overall CHP plant)	%	91,0

Connection points within the scope of construction of a new block

Fitting the new block into the existing system of the CHP Source 1 at the operational level implies defining the connection points of the new block system to the existing systems of the CHP Source 1, as well as the eventual reconstruction of individual existing systems or their parts.

The points of connection within the scope of the construction of a new block are:

- Natural gas system

This point is elaborated in paragraph 6.2.1.2 for all the alternatives of CHP.

- Feed water preparation system

A new unit will be connected to the newly constructed chemical treatment section, as the existing one is worn out after over 40 years of operation, with degraded concrete structures.), whereby the chemically prepared water is fed into the feed water tank as part of the deaerator. In this context, it is necessary to create a connected pipeline from the chemical water treatment station to the supply tank of the new block.

- Waste and oily water system

The waste and oily water system must be connected to the existing wastewater system.

- Connection to the power grid of **CHP - type 5 [Gas engines Jenbacher J920FleXtra]**

For connection of alternative E of new CHP, type 5 are proposed three different options: (1) radial connection, (2) double links connection and (3) radial/block connection. While option 1 is the cheapest solution and has smallest space requirements, it has lower reliability of operation. Option 2 solution is the most reliable because of redundant links but implies highest cost and largest space. Option 3 connection has medium cost and lower reliability. All three options consider cables with length of approx. 0.4 km and connected to 110 kV outdoor switchgear (bay) at the existing substation SS CHP Source 1, see Figure 6-14. Ampacity of the cable shall be compatible with installed power of the plant (192.6 MW) - it is recommended to use single-pole aluminium conductor cables with cross-linked polyethylene insulation, (XLPE Al 2000 mm^2) that has rated power higher than 200 MVA. In case of options 3, due to the small nominal capacity and large number of units, it is rational to have three 110 kV radial block connections (step-up transformer + cable) where each link will integrate group of six units; cables should have smaller ampacity of about 80 MVA (XLPE Al-300

mm^2) due to nominal rating of the units. The number of single-pole cables are different for all three options, please refer to heading "Connection to the power grid" on this section for more details.

- Connection to DHS

The connection of the new unit to the system for heating of DHS water will be carried out in parallel with the existing exchangers of the existing CHP blocks at CHP Source 1, as it is shown in Figure 6-25. In this context, it will be necessary to carry out an appropriate reconstruction of the system, because the pipes are relatively large dimensions, the placement of which can represent a certain problem.

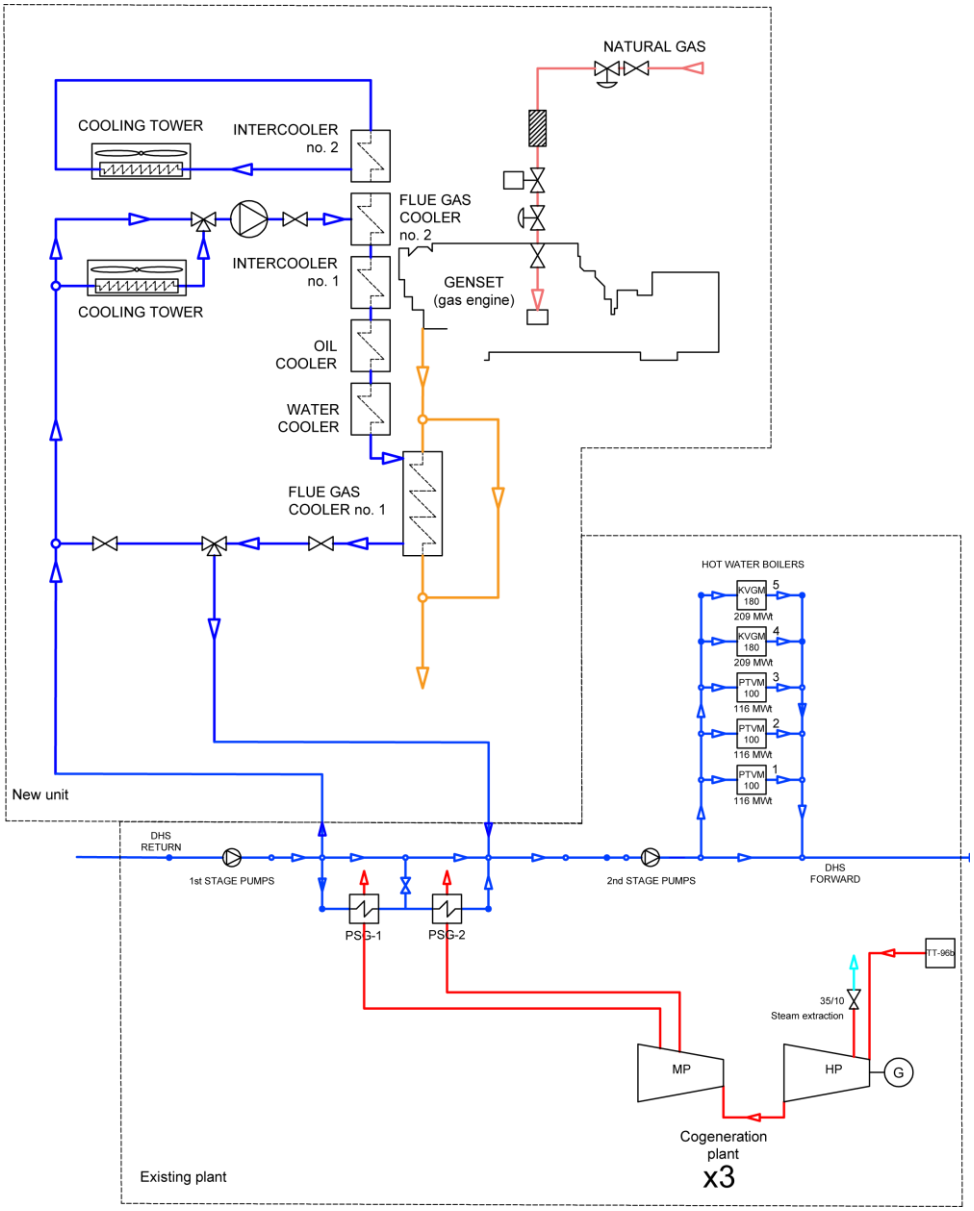


Figure 6-25. Connection to DHS

6.2.2 Description of Different Alternatives of Complementary Facilities and Technologies for Heat Energy Generation From Renewable Energy Sources, Waste to Energy and Combination With Thermal Energy Storage Facilities

Complementary facilities (CF) represent units that are considered as future investments to meet specific national and/or local goals and encompass renewable energy sources (RES), like solar collectors and heat pumps, waste-to-energy (WtE) plant, as well as electric water boiler and energy storage system.

In the study, the following technical-technological solutions are considered for scenario development.

- Waste-to-energy (WtE) plant
- Heat pumps
- Electric water boiler
- Solar collectors
- Thermal energy storage (TES)

6.2.2.1 Waste to Energy (WtE) plant

The main goal of energy recovery of waste via thermal treatment is to reduce the mass and volume of waste, the share of organic substances in waste, the destruction of organic harmful substances, and the utilization of energy stored in waste, while enabling the separation of inorganic substances (precious metals, glass that can be sold on the market of secondary raw materials).

Which technology will be chosen for the energy recovery process depends on the physico-chemical properties of the waste. Factors such as calorific value, moisture content of the fuel or particle size affect applicability and operational suitability. Therefore, it is necessary to pay special attention to the choice of technology depending on these parameters.

Today, the following technologies are most often applied for the energy recovery of waste:

a) combustion on the grate
b) rotary kiln
c) incineration in a fluidized bed

There are other technologies that have not found widespread use:

d) Pyrolysis
e) Gasification

Comparisons of the waste incineration technologies is given in the following table.

Table 6-13. Comparative analysis of important features of waste incineration technologies

Technology	General characteristics	Advantages	Disadvantages
Grate - air cooled	- heating value of fuel 5-16.5 MJ/kg - 5-30 t/h per one line - temperature 850-1000°C - TOC 0.5-3% - share of fly ash 2-4%, share of slag 17- 22% of the input mass of fuel - mixed and other untreated heterogeneous solid waste - the possibility of accepting a certain amount of sludge for co-incineration - application in most modern power plants on mixed municipal waste (almost 90% of power plants on mixed municipal waste in Europe)	- widely applicable and well-proven technology at large plants (long history of application) - robust design with low maintenance costs - heterogeneous waste without special pre-treatment - no special restrictions on fuel particle size and impurity content low operating costs and high utilization factor (>90) %, >8000h) - large capacity reduces the specific investment cost	- not applicable for powdered or liquid fuels - when co-incinerating sludge, prior drying (90% dry matter) is required, or separate introduction into the chamber, a maximum proportion of 10% thermally if it has a low proportion of dry matter (25-30%) - narrow range of heating value of the fuel - a larger amount of flue gases increases the investment in purification technologies - a higher proportion of NOx in the flue gases due to higher combustion temperatures
Grate - water-cooled	- lower calorific value of the fuel 10-20 MJ/kg - 5-30 t/h - unburned carbon in the slag (TOC) 0.5-3% - the rest as with the air-cooled grid	- fuel with a higher calorific value - the possibility of better control of the combustion process - the rest is the same as with the air-cooled grate	- more complex design - due to the higher calorific value of the fuel, there is a greater risk of damage to the grid - higher investment costs - higher maintenance costs
Fluidized bed - stationary	- does not find wide application for the recovery of mixed municipal waste - 5-25 MJ/kg - temperature 800-900°C - fuel particle size up to 50mm - sand particle size in the layer 0.5-1.5 mm, flow speed around 0, 9-3m/s, layer height 0.5-1.5m- up to 25 t/h- TOC < 1% (0.1-1% most often) - frequent application in sludge burning (3.5-6.5 MJ /kg for independent combustion) and co-incineration of sludge together with waste fuel	- tolerates fuel with a high moisture content due to a stable combustion process, uniform temperature and oxygen concentration - homogeneous combustion due to good fuel mixing in the layer - due to lower combustion temperatures, lower NOx emissions are achieved - a smaller amount of flue gases reduces investment costs in its purification - a wide range of heating fuel values - due to the size of the fuel particles and the combustion conditions, it has a more complete combustion - a smaller proportion of unburned substances and solid residues - a smaller amount of slag compared to the combustion technology on the grate - lower investment costs than with combustion on the grate if no investment in fuel preparation technology is required location	- requires better fuel pretreatment (removal of heavier fractions, metals) - due to a higher proportion of impurities with a low melting point, agglomeration and clogging of the nozzles may occur - higher consumption of sand - additional requirements for the size of fuel particles (< 50mm) - possible erosion of the exchanger due to the drift of sand particles - higher internal electricity consumption (12-20% depending on fuel pre-preparation technology) due to maintenance of the fluidized bed (fans) - greater amount of floating ash due to higher flow speed and use of smaller fuel particles - requires a wider professional staff and careful handling - need for pre-preparation fuel increases investment costs - higher maintenance costs and lower operability compared to the grid

(continuation of the previous table)

Technology	General characteristics	Advantages	Disadvantages
Fluidized bed - circulating	- wide range of heating value of fuel 6-25 MJ/kg - size of sand particles in the layer 0.1-0.6 mm, flow speed 4-9 m/s - up to 70 t/h - share of floating ash 3-5%, slag content 15-18% - the same as with stationary fluidized bed technology	- the most common application in larger power plants (>100MW) - greater fuel flexibility than in a stationary fluidized bed - prolongs the reaction time of combustion and gas mixing, which leads to better combustion and greater utilization - the technology enables the placement of the last heat exchanger in the particle retention layer, which makes it possible to reach high steam parameters (up to 500°C)	- higher requirements for the size of fuel particles - higher consumption of the material used in the layer (sand) and higher erosion of the exchanger due to the higher velocity of the gas flow than with the stationary layer - higher amount of floating ash - higher investment costs due to the need for fuel preparation - higher maintenance costs and lower operability in relation to the grid - requires professional staff and careful handling
Rotary kiln	- also applicable for liquid, gaseous fuels - < 16 t/h - TOC < 3% - the most commonly used technology for burning hazardous waste (900-1200°C)	- very well-proven technology for accepting different types of waste - by using a chamber for additional combustion, organic compounds in flue gases burn without residues	- input quantity per line limited in relation to combustion technology on the grid - higher temperature can damage the refractory lining - possible use of water or air-cooled lining, which makes the investment more expensive - large volume of flue gases (6000 - 10000 m3/t) - higher specific cost - longer fuel retention time in the combustion chamber
Pyrolysis	- for smaller plants 1-10 t/h - pretreated mixed municipal waste - no special limit for the share of inert materials - less used and proven than incineration technology	- the use of synthetic gas for various applications - a very low amount of flue gases reduces the investment for purification technologies	- complex process control - requires a high level of knowledge to manage the process - synthetic gas cleaning increases the already high investment costs - due to poor application, the technology is not proven and sufficiently well researched - requires a market for synthetic gas if it is not used at the combustion location
Gasification	- mixed plastic waste - pre-treated mixed municipal waste GIO/SRF - most often 20-50 t/ha, there are also applications in much larger plants	- technology that has found application in co-combustion in existing thermal power plants for fuel substitution - more flexible operation - use of synthetic gas directly in the combustion chamber or sale of cleaned gas on the market - proper handling results in low gas and dust emissions	- necessary pre-preparation of fuel by additional shredding - requires synthetic gas cleaning technology, which makes the investment even more expensive - required professional staff to operate the plant - higher operating and maintenance costs

Considered technologies as a part of this study are **Combustion on the grate**, **Combustion in a fluidized bed**, and **Rotary kiln**

Combustion on the grate

Energy recovery of waste using combustion on grate technology is the most used technology in Europe. There are different versions of the combustion chamber, and they are classified according to the way the grate movement. The task of the grate is to continuously deliver fuel and position the main combustion zone within the firebox with by influencing the control parameters of the process, such as grid speed, amount of primary air, etc.

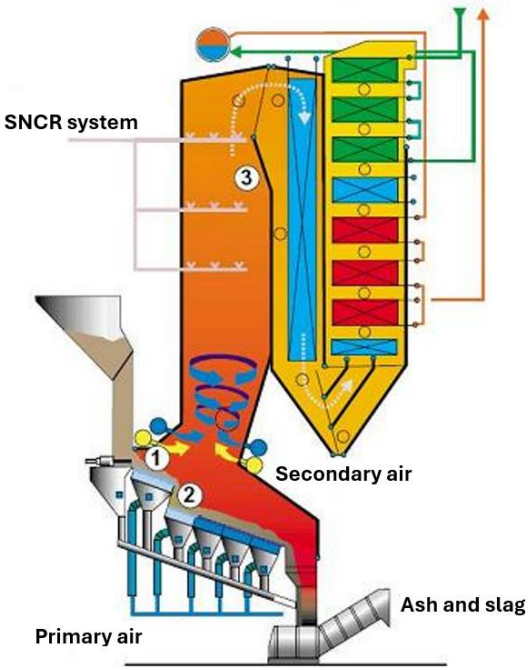


Figure 6-26. Schematic representation of the firebox and boiler with combustion technology on the grate

The primary air supplied from the lower side of the grate, in addition to being used for combustion, has a role of cooling the grate in order to regulate the temperature in the combustion area. Additionally, it prevents the formation of slag in the combustion chamber and mixes the flue gases for homogeneous temperature distribution. The primary air is supplied from the fuel tank, which creates a slight negative pressure and prevents the spread of unpleasant odors from the tank.

The air-cooled grill version is used for fuels with a calorific value of less than 16 MJ/kg. By using fuel with a higher calorific value (14-20 MJ/kg), the amount of primary air for cooling would be greater than that required for combustion. In this case, water cooling or a combined cooling of the grate with water and air is used.

Secondary air is supplied to the area of the combustion chamber, which also helps in maintaining the temperature of the flue gases in the combustion chamber at least 850°C for a minimum of 2 seconds. The temperature in the combustion chamber is usually around 950 °C, with a fuel retention time of 40-60 minutes.

In order to ensure complete combustion with less than 3% organic carbon in slag and ash, it is necessary to supply more air than the amount that is stoichiometrically required for combustion. Excess air is reduced on the primary side if water is used to cool the grate, and on the secondary side by recirculation of part of the purified flue gases (about 15%) and better mixing of the secondary air in the combustion chamber. With this, it is possible to achieve a better level of action.

During the cold start, auxiliary burners are used to heat the combustion chamber to the required temperature. This is the main task of auxiliary burners, and they can be automated, so that they are automatically switched on if the temperature in the combustion chamber falls below the required temperature during the process. During plant shutdown, these burners are usually used only if waste is still in the combustion chamber.

The technology has less requirements regarding fuel particle size. This leads to lesser requirements for pretreatment of the particles by shredding. Smaller fuel particles can fall through the grate and end up as an unburned part of the fuel, therefore grate combustion it is not applicable for powder or liquid fuels.

Due to the larger air flow, i.e. the larger amount of flue gases during combustion, a larger flue gas treatment plant is also needed, which usually increases the investment price.

Combustion in a fluidized bed

The technology is slightly newer than grate combustion technology and has been used for the past 40 years. The development of the technology was stimulated by the need for the flexibility of burning coal in thermal power plants, which was of different calorific value and composition, with different moisture content.

The combustion chamber is made in the form of a vertical cylinder, on the lower part of which there is a layer of inert material (sand). Under the layer of sand there are nozzles through which preheated air is blown into the chamber, creating a fluidized layer. Waste is continuously fed into the fluidized bed from above or from the side, depending on the design and composition of the fuel.

In order for the combustion process to begin, the fluidized bed must be preheated. This is achieved by using oil or gas burners that are extinguished only when the minimum required temperature is reached and combustion becomes self-sustaining.

Fluidized bed combustion is commonly used for energy recovery of refuse derived fuel and sewage sludge with a low dry matter content (25 %). There are two main variants of fluidized bed boilers:

- stationary (bubbling) fluidized bed which can be in atmospheric pressure (AFBC) and elevated pressure (PFBC) variant. A special variant of this solution is a solution with a rotating fluidized bed, which is adapted to the combustion of waste.
- circulating (CFBC) fluidized bed in which a much better heat exchange is achieved, which enables the production of boilers with much higher power and efficiency.

The technology requires pre-treatment of the waste in order to achieve homogenous composition and to reduce the fuel particle size to a maximum of 50 mm in diameter. It allows the use of fuel with a different calorific value range (5-25 MJ/kg), and tolerates fuel with a high moisture content due to a stable combustion process, which enables plant flexibility.

Due to the inertia of the heated sand in the layer, a uniform temperature is achieved in the combustion chamber, which is generally lower than combustion on the grate. Homogeneous conditions allow more efficient control of the entire process, and the emission of carbon monoxide and nitrogen oxides is reduced. Fuel particle sizes and combustion conditions ensure more complete combustion, which implies a smaller proportion of unburned residues and slag. The technology requires slightly less air in the circulation, which reduces the size of the flue gas treatment plant.

Fuel particles carried away by the air current can burn only at the higher layers of the combustion chamber, which can lead to problems with corrosion, creation of high temperature pockets and burnout of the heat exchanger. The circulating layer separates the unburned particles using a cyclone and returns them to the sand layer, which partially avoids this possibility. Due to the flow of fuel particles and sand in the combustion chamber at high speeds (3-9 m/s), the need for regular maintenance is increased in order to avoid possible damage due to material erosion.

The electricity consumption for covering internal needs of such plant is slightly higher than in the case of grate combustion technology due to the increased requirements for the preparation of fuel by shredding, and the need to ensure air flow in order to achieve fluidization of the layer in the combustion chamber. Due to the vertical flow of air to achieve fluidization of the sand in the layer, there is an increased amount of fly ash that is separated on the filters.

There is a system of gas burners to start the boiler. If necessary, these burners can also be used for emergency situations when there is no fuel from waste and the boiler must be kept in operation.



Figure 6-27. Section of a combustion chamber with combustion in a fluidized bed: stationary (left) and circulating (right)

CHP unit based on this technology will be used in scenario development and is further analysed in chapter 6.2.2.1.1 CF (type 1) - Stationary (bubbling) fluidised bed WtE CHP plant.

Rotary kiln

In contrast to the combustion on the grate, technological solutions that use a rotary kiln are more adapted to the burning of certain types of hazardous waste, considering that in addition to solid waste, liquid wastes can also be burned. Temperatures range from 500 °C in the gasification part of the process, up to 1,250 °C.

The combination of a rotary kiln and an additional combustion chamber has proven to be very successful in processing hazardous waste, regardless of its aggregate state. Solid waste retention time is usually 2-20 min. The additional combustion chamber ensures the additional combustion of flue gases from the furnace, as well as the combustion of liquid and gaseous wastes that are subsequently added. Temperatures in the additional combustion chamber range from 900 to 1,200 °C. Most plants have the option of injecting secondary air for subsequent combustion. Due to high temperatures and secondary air injection, the combustion of flue gases is complete and organic compounds (hydrocarbons of low molecular weight, polycyclic aromatic hydrocarbons (PAH), polychlorinated biphenyls (PCBs) and dioxins) burn without residues.

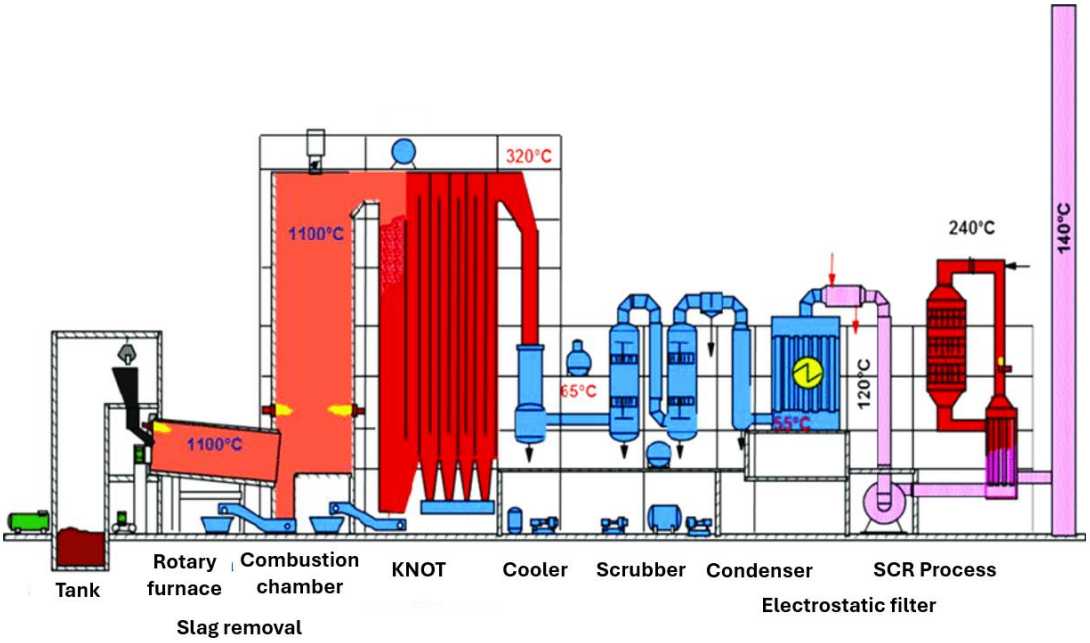


Figure 6-28. Rotary furnace for burning hazardous waste

6.2.2.1.1 CF (type 1) - Stationary (bubbling) fluidised bed WtE CHP plant

In this chapter considered WtE plant configuration, which will be used in scenario development, is further analysed. This WtE plant operates on a single-line configuration with the key components being a stationary (bubbling) fluidized bed (BFB) RDF-fired steam boiler and a condensing steam turbine equipped with a 3 bar (absolute) steam extraction. The process begins with the combustion RDF in the steam boiler, where the chemical energy stored in the RDF is converted into thermal energy, producing high-pressure steam.

This steam is then directed to the condensing steam turbine where it expands and drives the turbine blades, converting the thermal energy into mechanical energy. The turbine is specifically designed to extract steam at 3 bar (absolute). This higher-pressure steam from uncontrolled extraction, together with backpressure outlet steam is used for heat supply of DHS heat exchangers, providing a substantial thermal output of 54 MWt to meet local heating demands.

All condensed steam from the network water heaters and feedwater preheater is collected in feedwater tank which is supplemented with demineralized water as needed to compensate for water losses in the system (boiler blowdown, sludge removal and condensate loss from process steam). The feedwater tank is equipped with a deaerator which is supplied with low pressure steam. After exiting the deaerator, the feedwater which then enters steam generator once again completing the cycle and initiating a new one.

By maximizing both thermal and electrical outputs, this process achieves a net electrical output of 17.77 MWe, which is fed into the grid, contributing to the overall energy supply while simultaneously reducing waste volume that would otherwise end up in landfills.

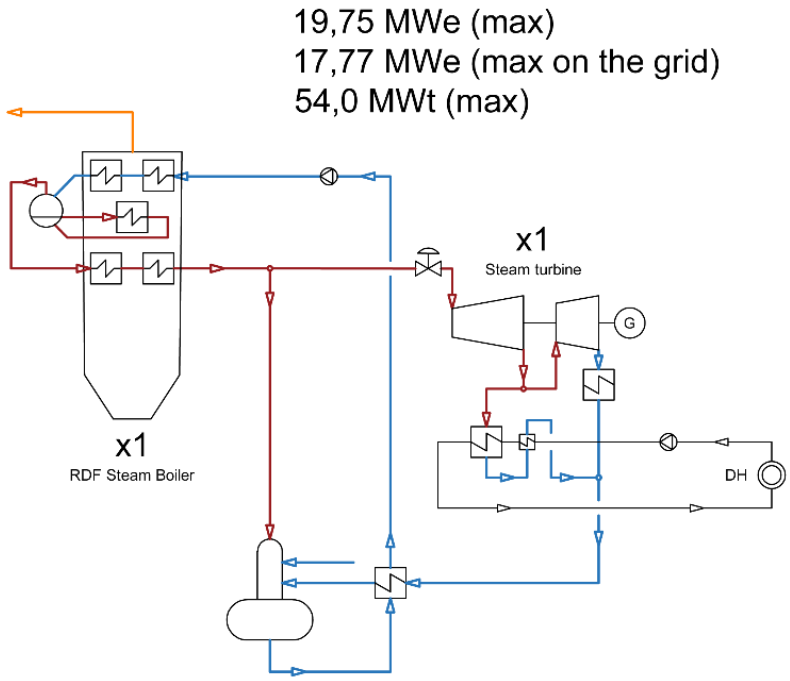


Figure 6-29. Waste to energy plant

Overall technical characteristics of CF (type 1) configuration is given in following table:

Table 6-14. Technical characteristics of the WtE plant

WtE Plant	Unit	CF (type 1)
Boiler type		BFB boiler
Capacity (RDF)	t/y	200,000
Steam turbine type		Backpressure with steam extraction
Steam extraction pressure	bar	3
Gross power output	MW	19.75
Net power output (on grid)	MW	17.77
Heat output	MW	54
Efficiency (CHP production)	%	78

Location of the WtE plant

In consultation with Termoelectrica, micro location for building new WtE plant is identified - Figure 6-30. It is a location of the decommissioned **HOB East plant** (coordinates: 46.969763, 28.917232). or in the vicinity of that location HOB East was intended to produce predominantly heat and industrial steam.

HOB East is located, as the name said, on the **south-east side of the city**. The plant area is 11,0 ha and the installed heat capacity is 360 Gcal/h of district heating heat and 100 t/hr of steam. The boilers were installed 1992-1995 and used natural gas and heavy fuel oil for operation. The installed water treatment capacity is 315 m3/h. HFO was supplied by the railroad and the storage tanks capacity was 15.000me 3 (3 x 5000 m3). CT-East is connected to DHS and equipped with three DH network circulation pumps, type СЭ-2500 x 180, with capacity of 2,500 m3/h, head pressure of 18.0 bar and power of 1600 kW.

HOB East is decommissioned and is not the property of Termoelectrica. thisT location has advantages for construction of WtE plant - heating network, electrical network, gas pipeline, water pipeline,

sewage pipeline, etc. were built to this location. In addition, this location is the most suitable for the purpose of building WtE plant, land for waste storage is available within this region and it is situated quite far from residential sectors.

Land acquisition would be required for construction of the WtE plant in that location.



Figure 6-30. Location of WtE plant

The selection of the final location for the construction of the WTE plant must be agreed by the local and central authorities.

Fuel availability – Waste for thermal treatment

According to an older report "Pre-feasibility Study of a Waste to Energy Plant in Chisinau, Moldova", the needed capacity for thermal treatment of waste is 400,000 tons per year, and the proposed waste-to-energy plant is 54 MW plant with an electric capacity of 20 MWe.

Another recent report "Waste characterization study and evaluation of Moldova's prospects for waste-to-energy production - Final report on one-year waste composition survey". In this survey analysis of quantities, physical composition, and chemical analyses of waste in Chisinau and Balti

municipalities are analysed, and capacities of waste-to-energy plants are proposed. Results show waste generation on the level of 309,000 tons in Chisinau and 129,000 tons in Balti in 2024. The energy potential for the year 2030 was estimated based on projections regarding waste generation, results of composition analysis, and chemical analyses of waste sampled in these regions. The waste generation analyses are based on the calculation of Waste Generation Indices (WGIs) considering expected economic development, and projected WGIs were established for negative, low-growth, and high-growth scenarios up until 2030. According to the estimations for the Chisinau municipality, a plant of an average capacity of 46 MWe would be possible, with a range from 42.1MWe for the Negative WGI scenario to 50 MWe for the High WGI scenario. However, it is noted that the estimated energy potentials are the maximum ones since in this estimation the recycling rates are assumed to be the same as in the present context and no further recycling has been considered. This means that if an increase in recycling of recyclable fractions is considered the energy and electricity potential would be lower.

Also, on the basis of Moldova Environmental Protection Agency data in publication Waste Management in the Republic of Moldova published collected raw waste quantities on the national level in the area of 660,000 tonnes. Published data per year can be seen in the following table.

Table 6-15. Waste collection data per Moldova Environmental Protection Agency

Collected municipal waste / Year	2019	2020	2021	2022
Mixed municipal waste	482,877.70	638,989.28	683,915.76	655,238.30
Market waste	480.00	515.36	521.90	724.79
Street waste	63.00	80.00	7,759.50	2,389.87

Taking into account circular economy goals and prioritising of material recovery/recycling, all this waste needs to be subjected to secondary separation to remove recyclable fractions, and the residual waste can be considered refuse derived fuel (RDF) that can be thermally treated. Thus, building of WtE facility implies changes in waste management system. Based on this presumption, and all available data on waste generation/collection, collected quantities of waste in Republic of Moldova are in the range of 400,000 to 660,000 tonnes per year, resulting in 180,000 to 300,000 tonnes of RDF susceptible as a fuel for WtE plant. Also, in this analysis future waste generation projections need to be taken into account, increase in separate collection and recycling, secondary waste separation, as well as transport problems and cost effectiveness. Due to this, in the analysis, 200,000 t/y WtE units are considered in envisaged scenarios, where one or two of such units are used in different alternatives.

For further calculations, RDF with **LHV of 12 MJ/kg** is assumed, share of fossil carbon in RDF of 40%, and emission coefficient of fossil carbon in solid RDF of **50 t CO_2/TJ**.

6.2.2.2 Heat Pumps

Heat pumps use the energy potential of low-temperature heat (from lower-temperature heat source) by increasing its temperature level, releasing more valuable energy, i.e. higher-temperature heat (to higher-temperature heat sink). Such energy, with a higher temperature, exists as useful energy for covering energy needs. In other words, heat pumps are devices that increase the temperature level of very often widely available energy (heat of air, surface water, soil, geothermal water) to a temperature level at which heat can be used. The mentioned heat sink and heat source of different temperatures can be categorized as:

• Heat source: a heat reservoir with a lower temperature level from which heat energy is taken away. Heat source are often represented by widely available sources, such as ambient air, surface and underground water, soil, solar energy.

• Heat sink: a heat reservoir with a higher temperature level to which heat energy is supplied, i.e. delivered. Heat sink represent the conditioned air of the space that heats, heating water or some form of heating medium.

For the aforementioned increase in the temperature level of the available thermal energy heat pumps require mechanical work for their operation. The amount of mechanical work required to operate the heat pump depends on the difference between the temperature levels of the required and available thermal energy (the difference between the temperature levels of the heat sink and the source). The greater the temperature difference, the more mechanical work needs to be done in order to transfer energy from a lower to a higher temperature level. The just-mentioned temperature difference is one of the key factors that limit the usefulness and thus the application of heat pumps.

Heat pumps can be divided according to various criteria. One of the basic criteria is the driving energy of the heat pumps. Accordingly, we distinguish mechanical, i.e. compressor driven heat pumps, and sorption heat pumps, i.e. thermally driven heat pumps. As part of this study, only mechanical heat pumps powered by electricity will be considered.

When choosing the type and mode of operation of heat pumps, it is necessary to know the basic parameters that define the field of operation of the specific heat pump, such as: the temperature level of the lower temperature heat source (evaporation temperature), the temperature level of the higher temperature heat sink (condensation temperature) and the available amount of energy of the heat source that can be extracted. In addition to the above, it is necessary to define the working medium of the heat pump, which can be divided into the following groups:

- halogenated hydrocarbons,
- pure hydrocarbons,
- zeotropic mixtures,
- azeotropic mixtures,
- inorganic substances.

In January 1, 2015, the so-called F-Gas regulation that entered into force. The goal of the regulation is to reduce the use of fluorinated hydrocarbons as working substances and their impact on climate change. One of the main goals of the regulation is the complete withdrawal from the use of active substances whose global warming potential (GWP) is greater than 2,500 by 2020. The update of the F-Gas regulation from February 2024 further limits the use of active substances used in heat pumps and prohibits the export of refrigeration, air conditioning and heat pump equipment with GWP higher than prescribed. Thus, from 2025, any new commercial refrigeration equipment cannot use F-gas refrigerants with a GWP greater than 2500 and the new refrigeration equipment that is self-contained will no longer be permitted to use F-gas refrigerants with GWP greater than 150. Furthermore, in 2030, the current limit for any new refrigeration equipment will be entirely reduced to GWP 150. The alternative to banned substances are natural refrigerants such as CO_2, propane, isobutane, ammonia and water are sustainable. Also, there are new hydrofluoroolefin (HFO) refrigerants, such as R1234 yf/ze/zd and R1233zd whose GWP values are below 10, which are offered as alternative refrigerants.

For this reason, in the continuation of this study, the use of the working substance called R1234ze is considered as a substance that offers long term regulative acceptance and thus ensures market availability.

Heat pumps can also be used for cooling purposes, i.e. production of cooling energy. In doing so, the principle of operation and the components of the heat pump remain the same, while the medium from which the heat is removed (conditioned air, cooling water) becomes a heat source, and the medium to which the heat is transferred to (environment, underground and surface water) takes on the role of a heat sink. As part of this analysis, the use of heat pumps for cooling needs will not be

considered, however, it should be noted that the installation of a heat pump creates an additional product - cooling energy, which represents an additional option for the investor. Of course, for the above, it is necessary to ensure utilization of produced cooling capacity.

If the use of heat pumps for covering DHS heating needs is considered, then it is necessary to bridge a large temperature difference between the heat source and the heat sink. Namely, the temperature of the ground or wastewater, which have relatively low temperatures during the peak heating season, can be used as a heat source for the heat pumps at the site location. In such cases, special versions of heat pumps are used, such as cascade heat pumps or multi-stage (most often two-stage heat pumps). Such designs have various positive effects on the technical performance of heat pumps. The cascade type of heat pump is a system that essentially consists of two heat pumps, each of which uses a different working substance. The multi-stage type of heat pump uses the same working substance, but has multiple compression stages.

In order to evaluate the performance of the heat pump, the so-called COP factor (Coefficient of Performance), which is also called heating factor or thermal multiplier, is defined as a basic value for evaluating the efficiency of heat pumps in the heating regime. The COP factor is defined as the ratio of the useful, produced heat and the electricity required to operate the heat pump.

If the operation of the heat pump in the cooling mode is considered, i.e. when the heat pump produces cooling energy, the so-called EER factor (Energy Efficiency Ratio), i.e. cooling factor, is used as a value for evaluating the operation of the heat pump. The EER factor is defined as the ratio of the removed heat, i.e. the cooling effect, and the electrical energy required to operate the heat pump.

COP and EER factors are highly dependent of temperature difference between heat source and heat shink. Below are graphical representations of the COP and EER factors for a two-stage heat pump. It should be noted here that the given representations of the COP factor are purely illustrative, i.e. they serve to illustrate the change of the COP factor depending on the temperatures of condensation, i.e. temperature of evaporation.

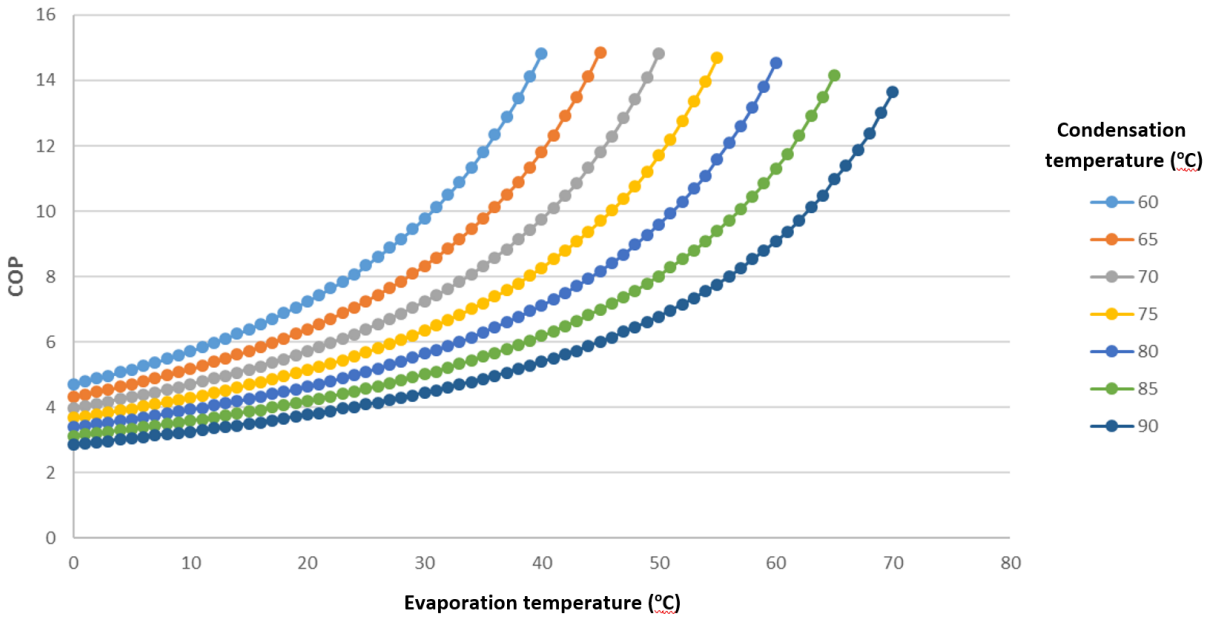


Figure 6-31. COP in dependence of evaporation and condensation temperatures

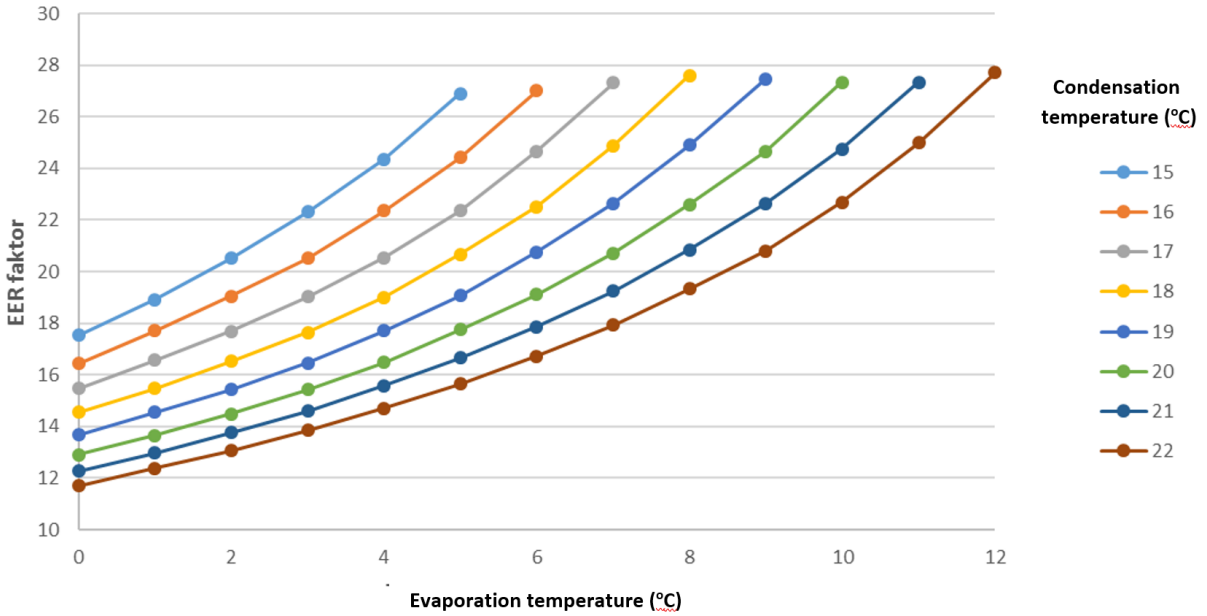


Figure 6-32. EER in dependence of evaporation and condensation temperatures

Unit based on this technology will be used in scenario development and is further analysed in the subchapter 6.2.2.4.

As provided location of heat pump facility is Central wastewater treatment plant, available heat sources for heat pumps are geothermal energy and wastewater from wastewater canal.

6.2.2.3 CF (type 2a) - Geothermal two-stage R1234ze heat pumps

The system is designed to integrate one or more heat pumps in a scalable configuration, supporting up to ten individual units. Each heat pump possesses a substantial thermal capacity of 20 MW, making it a robust solution for large-scale heating applications. The heat pumps employ a two-stage compressor design and utilize R1234ze as the working fluid.

The system harnesses geothermal energy as its heat source, utilizing a network of vertical ground probes. These probes, extending to a depth of approximately 130 meters, are embedded in the ground to extract low-grade thermal energy from the earth. The extracted heat is then transferred to the working fluid within the heat pump system.

For a single heat pump, up to 3,500 ground probes may be required, necessitating an estimated land area of 130,000 m² per unit. This extensive probe field is essential for ensuring a stable and sufficient heat supply, enabling continuous operation under varying load conditions. Given the significant thermal output requirements, a thorough analysis of the available geothermal energy at a specific location is necessary to determine the feasible extraction potential.

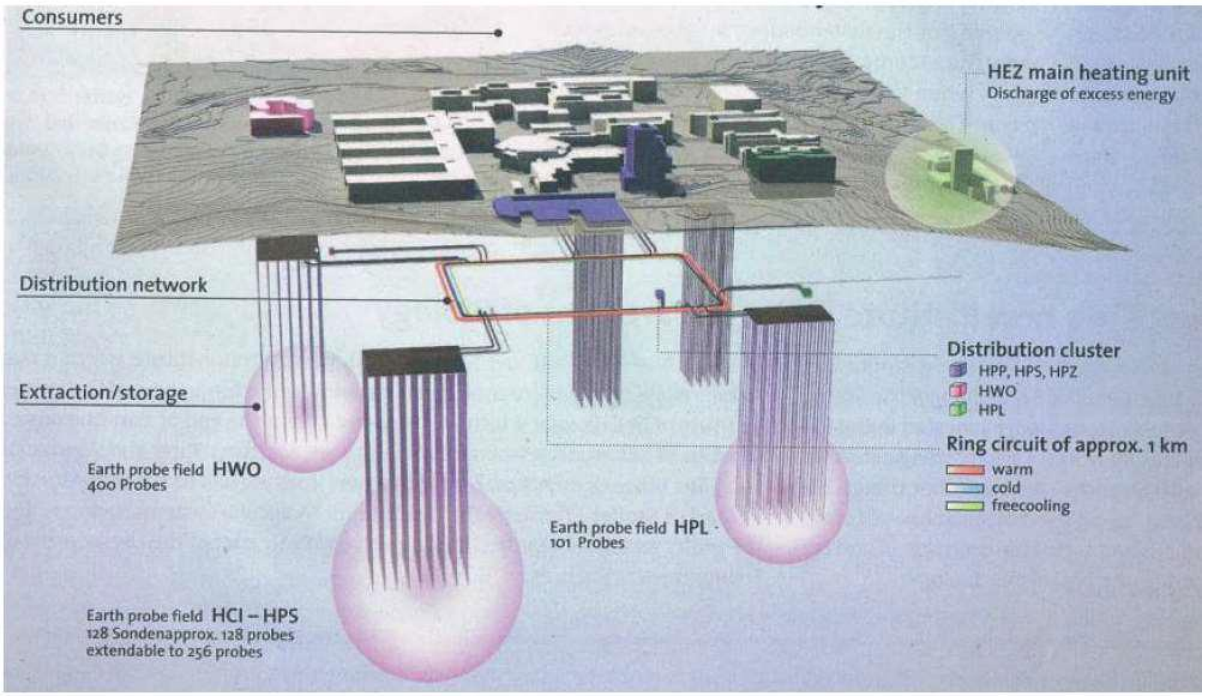


Figure 6-33. Example of 5.5 MW geothermal heat pump with ground probe field (434 probes, depth 200m)

During operation, the heat pumps absorb heat either from the ground via vertical probes or from wastewater through heat exchangers. The working fluid, R1234ze, circulates through the evaporator, where it absorbs thermal energy from the heat source and evaporates into a low-pressure gas. The gas is then compressed by the compressor, increasing its temperature and pressure to levels suitable for heating applications.

The high-temperature, high-pressure gas is subsequently directed to a condenser, where it releases heat to the heating system, typically for space heating or industrial processes. After transferring its heat, the working fluid condenses back into a liquid and passes through an expansion valve, which reduces its pressure and temperature before re-entering the evaporator to repeat the cycle.

This closed-loop process is highly efficient, particularly when implemented across multiple heat pumps, ensuring a reliable and consistent heat supply. The system's reliance on geothermal energy - a renewable and stable heat source - further enhances its sustainability and long-term viability.

The modular design of the system allows for flexibility in deployment, enabling customization to meet specific site conditions and heating demands. By adjusting the number of heat pumps and the corresponding ground probe field, the system can be optimized for varying scales of operation, from individual large buildings to extensive district heating networks. In the analyzed case, the system achieves a coefficient of performance (COP) of 3.4.

Due to the exceptionally large number of required ground probes, the associated very high costs (additional 18,2 mil. EUR for 20 MWt heat pump[31]), and the extensive area needed for the

[31] The investment cost of a ground probes ranges from €27 to €60 per meter, depending on the drilling method and geological conditions

construction of such a geothermal field, geothermal heat pumps were abandoned and are no longer considered in this study.

6.2.2.4 CF (type 2b) - Waste-water two-stage R1234ze heat pumps

The system is designed to integrate one or more heat pumps in a scalable configuration, accommodating up to ten individual units. Each heat pump has a substantial thermal capacity of 20 MW, making it a robust solution for large-scale heating applications. The heat pumps utilize a two-stage compressor design with R1234ze as the working fluid.

In operation, due to the comparable temperature ranges, this system functions similarly to the geothermal-based systems described in the previous chapter. However, instead of extracting heat from the ground, the heat pumps absorb thermal energy from wastewater via a network of heat exchangers positioned within the wastewater canal.

The maximum district heating (DH) capacity may be constrained by factors such as wastewater flow rate, temperature, and, if a wastewater treatment plant is present, the minimum required inlet temperature to avoid disrupting biological treatment processes.

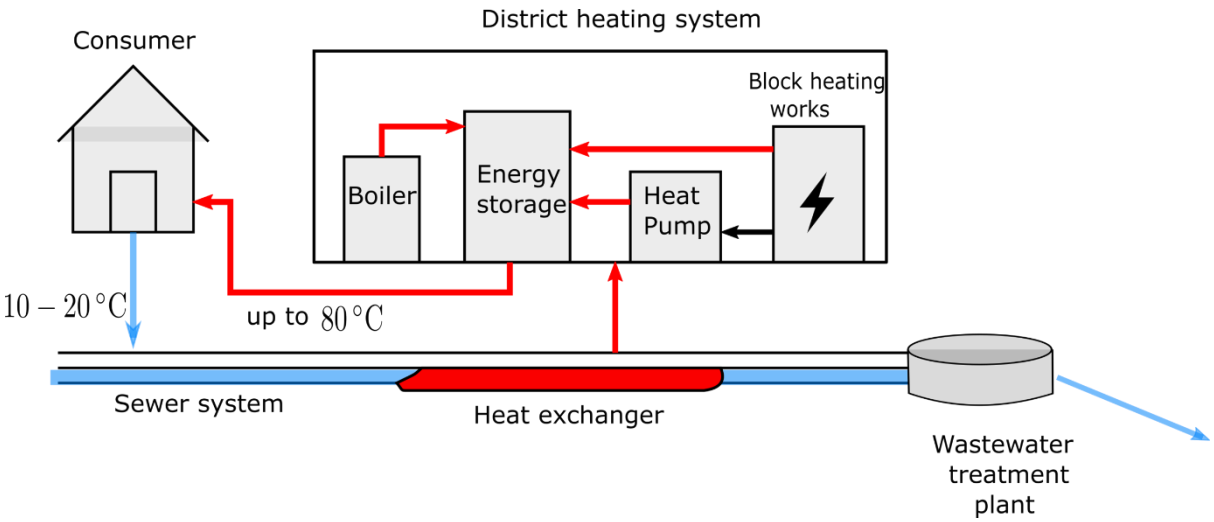


Figure 6-34. Waste-water heat pump as a part of district heating system

Based on the available data[32], the design capacity of the wastewater canal is 425,000 m³/day. However, the current average wastewater flow is significantly lower, at approximately 140,000 m³/day.

Assuming a temperature difference of 5°C between the wastewater entering and exiting the heat exchangers of the heat pump system, the estimated available thermal energy that can be extracted under current flow conditions is approximately 33.9 MWt. If the wastewater canal operates at its maximum design capacity of 425,000 m³/day, the potential heat extraction could increase

[32] Energy saving in wastewater treatment plants, Natalia Ciobanu Technical University of Moldova, Chisinau, Republic of Moldova (E3S Web of Conferences 212, 01003 (2020) ICBTE 2020)

substantially, reaching up to 105 MWt. This highlights the scalability of the system and the potential for significantly greater heat recovery under higher wastewater flow conditions.

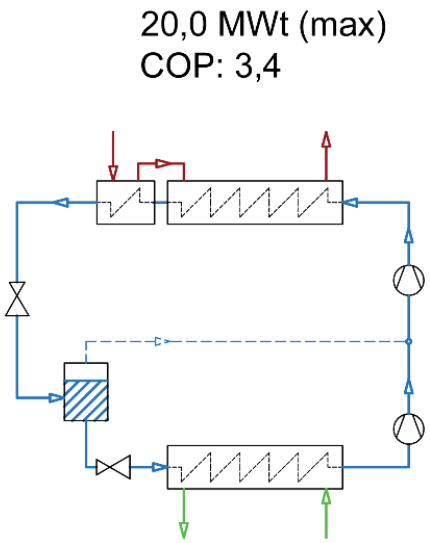


Figure 6-35. Heat pump

Overall technical characteristics of CF (type 2b) configuration is given in following table:

Table 6-16. Technical characteristics of the Heat pump-based plant

Heat pump	Unit	CF (type 2b)
Heat pump type	-	Compressor type
Number of stages	-	2
Working medium	-	R1234ze
Heat source	-	Waste water
Heat extraction method	-	Heat exchanger (in pipe)
Heat exchanger area	m^2	n/a
Electricity consumption (per heat pump)	MW	5.88
Heat output (per heat pump)	MW	20
Efficiency (COP)	-	3.4

In analysis of alternatives, one **heat pump** will be analysed, with overall **heat output of 20 MW** and **electrical power of 5.9 MW_e**.

6.2.2.5 Air-to-Water Heat Pumps for Summer Heat Load Coverage

Selection of Heat Pump Technology

When considering heat pump technologies for large-scale district heating systems, efficiency is the most critical factor. In this regard, water-to-water heat pumps (also known as water-source heat pumps) are generally a superior choice compared to air-to-water heat pumps.

Water-to-water heat pumps extract heat from stable water sources, such as groundwater or, in this case, a wastewater canal. These sources typically maintain a consistent temperature year-round, usually between 10–15°C. This thermal stability allows water-to-water heat pumps to operate at higher efficiency levels, achieving a superior coefficient of performance (COP) compared to air-to-water heat pumps.

In contrast, air-to-water heat pumps rely on ambient air as their heat source, which can experience significant temperature fluctuations, particularly in winter. As outdoor temperatures drop, the efficiency of air-to-water heat pumps decreases, leading to higher energy consumption. Furthermore, during cold weather, air-to-water systems require periodic defrosting cycles, further reducing their overall efficiency.

While air-to-water heat pumps may have a lower initial installation cost, this advantage is often outweighed by their lower efficiency (during cold weather), particularly when dealing with large-scale heat pump applications. Given the specific requirements of the district heating system in Chisinau, water-to-water heat pumps are the recommended solution due to their superior efficiency, reliability, and long-term cost-effectiveness. The recommended wastewater-to-water heat pump would be capable to operate efficiently throughout the year (not only during the summer).

Technical and Economic Analysis of Air-to-Water Heat Pumps for Summer Heat Load Coverage

Performance of air-to-water heat pumps is generally higher during warmer months, thus they could be an efficient source of heat during the summer.

However, installing air-to-water heat pumps for seasonal application (only covering summer heat loads), considering the high upfront costs of industrial-scale heat pumps, combined with installation and integration expenses, would represent an inefficient capital investment, particularly in the context of the other planned and proposed high-efficiency heat sources for the DH system in Chisinau.

A heat pump system designed for the summer season use would remain idle for a part of the year, leading to poor asset utilization.

Other planned and proposed technologies offer better economic and technical performance:

- **Solar Thermal Collectors**: A renewable energy cost-effective solution for summer heat production. Solar thermal systems operate with zero fuel cost, minimal maintenance, and can provide thermal energy during peak sunshine hours. Unlike heat pumps, which consume electricity, solar collectors operate passively and are an industry-standard solution for summer hot water production.
- **Planned high-efficiency CHPs based on gas engines**: High-efficiency CHPs with total electricity generation capacity of circa 55 MW and heat generation capacity of at least 50 MW, which are planned to be constructed under the current DHEIP-2 project. The new CHPs are planned to be operated to cover the summer DH load.
- **Proposed high-efficiency CHP Type 2**: When electricity will need to be produced and supplied to the grid to cover baseload / balancing needs during the summer using CHP Type 2, it will also be a heat source (in combination with the planned heat storage) for the DH system during the summer.
- **Wastewater-to-water heat pump**: Proposed wastewater-to-water heat pump, which could be operated throughout the year.
- **Waste-to Energy plant:** If/when the proposed waste-to-energy cogeneration plant would be built, it would also be capable to cover the summer DHW load.
- **Gas Boilers**: If necessary, gas-fired boilers provide an inexpensive and flexible backup heat source. Their CAPEX is significantly lower, and their operation can be adjusted dynamically based on demand.
- **Electric boilers:** In the future, if cheap electricity is available in certain periods (due to excessive production from renewable energy sources), electric boilers, having significantly lower CAPEX, could be used (in combination heat storage).

Conclusion: At this stage, investing in air-to-water heat pumps to cover the summer DHW load is not recommended by the Consultant.

Also, in the future there could be examined opportunities for integration of the heat produced by heat pumps providing cooling to buildings / data centers / district cooling systems (e.g. in areas with construction of modern buildings which would use both district heating and cooling services).

6.2.2.6 Solar Collectors

Solar district heating systems are still in the early development phase of the market, although their commercial application has already begun in some countries. Large solar thermal plants that supply heat networks of district heating systems represent only few percent of the total installed capacity of solar thermal systems in Europe. One of the characteristics of these systems is that they can fit well into different urban concepts, from small communities such as villages to parts of settlements, settlements or entire cities.

Solar district heating plants consist of a large field of thermal collectors that deliver the produced thermal energy to distribution networks in urban districts, smaller settlements or large cities. Fields of solar heat collectors are installed on free land or integrated on the roofs of buildings. The following picture shows an illustrative example of a solar district heating system.

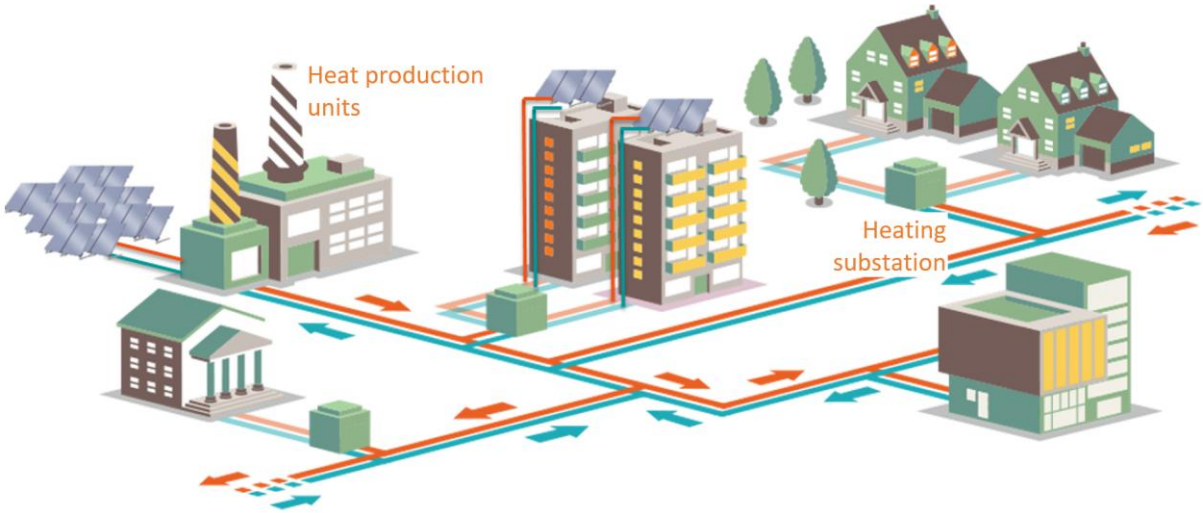


Figure 6-36. Solar district heating system

In terms of solar district heating, a system is considered large if it is greater than 350 kW_t (500 m^2), but today the power of the plant is up to 100 MW_t for the largest installed systems.

The usual share of solar heat is up to 20% in the total thermal energy produced in the district heating system. With the use of large-capacity heat storage tanks, which are also used to optimize cogeneration plants or in the production of thermal energy using electricity, the proportion of solar heat can reach up to 50%.

These systems can be applied wherever there are DH networks. Typically, these systems exist in colder climates where there is a significant demand for thermal energy during the cold seasons. Although it may seem that the application of solar thermal systems in these areas is neither competitive nor profitable, to date it has been proven otherwise in some cases.

From a technical point of view, solar heat can be combined with other energy sources for the production of thermal energy, but this is not always ecologically or economically profitable, and the application must be carefully considered.

Basically, these systems differ according to, among other things:

- the method of connecting the solar plant to the heating network,
- the size of the heating network to which solar heat is supplied,
- the type of solar heat collectors and the method of their integration,
- method of heat storage.

To date, different technological concepts for solar district heating have been developed in different countries. Two basic variables are the method of connection to the heating network and the size of the heating network. With regard to the way in which the solar plant is connected to the heating network, there are differences between centralized and decentralized solar plants, as shown in the following figure.

With the centralized method, the collector field is located near the main heat source, while with the decentralized method, the collector field is located at a convenient location, often far from the main heat source itself, and the heat network itself often serves as a heat reservoir.

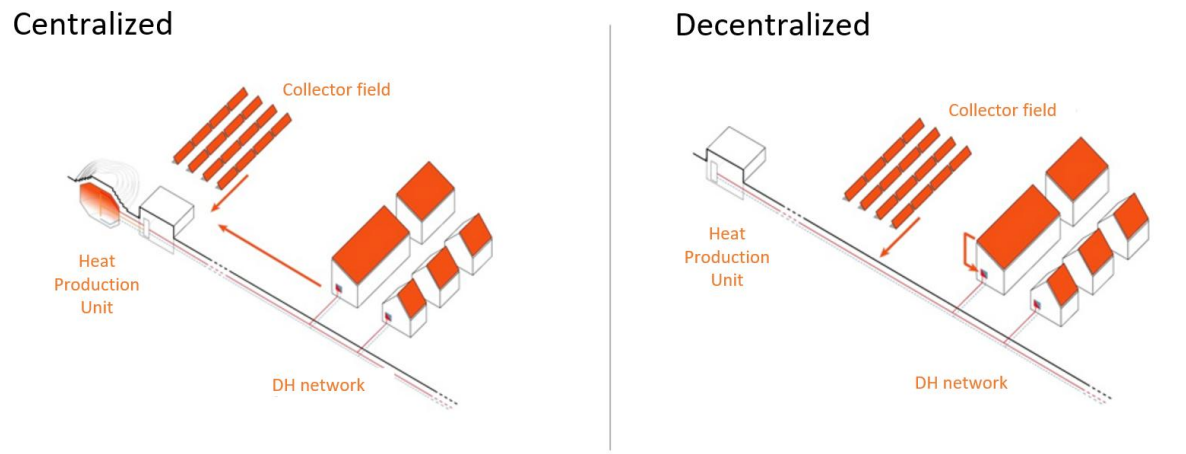


Figure 6-37. Technical concepts of solar district heating

Regarding the solar collectors, the most common type of collectors are F*lat Plate Collectors (FPC)*, followed by *Evacuated Tubular Collectors (ETC)* and the *Vacuum Flat Plate Collectors (VFPC)*.

The basic parts of the ***Flat Plate Collectors (FPC)*** are the absorber plate, pipe register, cover glass, insulation and housing. The absorber plate is coated with a special coating that absorbs solar radiation. The heat collected in this way is further conducted through the material of the absorber plate (thickness approx. 0.3 - 0.5 mm) towards the pipe register and finally handed over to the working fluid that flows through the pipe register.

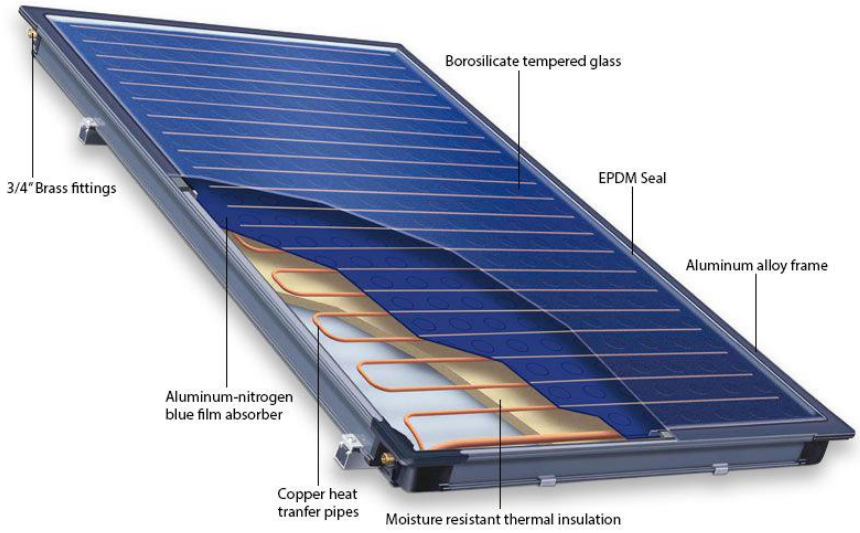


Figure 6-38. Flat Plate Collector (FPC)

The tubes are attached to the absorber either by soldering, laser or ultrasonic welding and sometimes by gluing. The mostly used selective absorber coatings characterized by high absorption coefficient for short-wave solar radiation (α = 0,9 - 0,96) and low absorption coefficient ($\alpha = \varepsilon$ = 0,06 - 0,2), i.e. emission for long-wave IR radiation, which represents heat losses of the collector. Such properties ensure at the same time a significant absorption of solar radiation and a substantial reduction of heat losses of the absorber plate heated by long-wave radiation compared to non-selective coatings (such as, for example, ordinary black paint).

Similar characteristics and role are played by the cover glass, whose permeability coefficient for short-wave solar radiation is high (τ = 0.9 - 0.95) and very low for long-wave radiation (τ < 0.02). In addition to reducing heat losses, glass also plays an important role in protecting the collector from atmospheric influences. In order to further reduce heat losses, the collector is insulated from the back and sides. Mineral wool or PU foam with a thickness of 30-70 mm is usually used for insulation, where the losses through the insulation amount to about 5-10% of the total losses of the collector.

They are intended for heating hot water up to 85 °C.

Vacuum tube collectors (Evacuated Tube Collector - ETC) are today, after plate collectors, the most used type of collector. They were developed to reduce convective losses from the absorber to the environment, which was done by extracting air (~10-5 mbar) from the space between the absorber and the glass.

With the standard construction of plate collectors, the resulting vacuum would cause the cover glass to crack, so with vacuum collectors, the absorber is placed in vacuumed glass tubes (which, due to the circular shape of the wall, have significantly lower stresses in the material at the same vacuum). In one type of collector, the fluid flows in two directions through a series of coaxial pipes connected in parallel, where the inner one is the return from the system (cold fluid) and the outer one is the outgoing one (heated fluid). As with plate collectors, the absorber is attached to the pipe (Figure 6-39 a), or the outer surface of the coaxial pipes, on which a coating has been applied (Figure 6-39 b).



Figure 6-39. Evacuated Tube Collector (ETC)

Vacuum tube collectors have lower heat losses compared to plate collectors under the same operating conditions. However, due to the necessity of using glass tubes, the useful area of the absorber is smaller in relation to the total projected area of the collector (ratio is about 0.6) compared to plate ones (ratio is about 0.9). The efficiency (and price) of vacuum, as well as plate collectors, is determined according to the total projected area of the absorber or collector. Because of this, the efficiency of vacuum collectors calculated in this way can be lower than that of plate collectors with identical absorber and glass characteristics. This is often the case in the part of the operating curve that corresponds mainly to the summer operating mode, i.e. at (ϑf,sr−ϑz) / Gsun = 0 - 0.05 Km2/W.

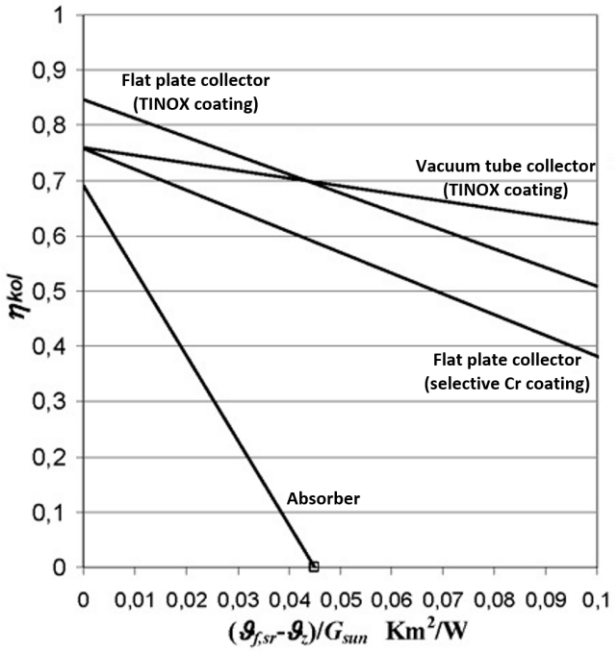


Figure 6-40. Comparison of efficiencies of collectors of different designs

In other words, if the same amount of solar energy is to be collected in the warmer half of the year as with plate collectors, vacuum collectors will occupy a larger area.

The opposite is true in the winter months, in cloudy weather or extremely high fluid temperatures (> 70 °C), i.e. at (ϑf,sr−ϑz) / Gsun = 0.05 - 0.15 Km2/W. Then the reduction of heat losses in vacuum collectors becomes more pronounced than in plate collectors, so their efficiency is also higher. This makes them suitable for use in colder climates with lower solar irradiance.

Due to lower heat losses, vacuum collectors enable higher outlet temperatures (max. 100 °C) to be achieved. This makes them suitable for use in, for example, solar cooling systems (absorption cooling).

As a disadvantage of vacuum collectors, it should be mentioned the possibility of glass cracking due to dilatations caused by temperature changes, which results in a loss of vacuum and a significant drop in efficiency.

Vacuum Flat Plate Solar (VFPC) Thermal Collectors are the type of solar collector combine the best properties of FPC and ETC collectors and have very good optical and thermal characteristics due to the combination of a large flat surface and good vacuum thermal insulation, which enables high efficiency and adaptability of the collector with various applications for industrial process heating and integration in buildings. Vacuum plate solar collectors consist of a solar absorber in a flat vacuumed housing with a glass or glass-metal cover sealed at the edges and a series of spacers that prevent the housing from being deformed due to the influence of external atmospheric pressure.

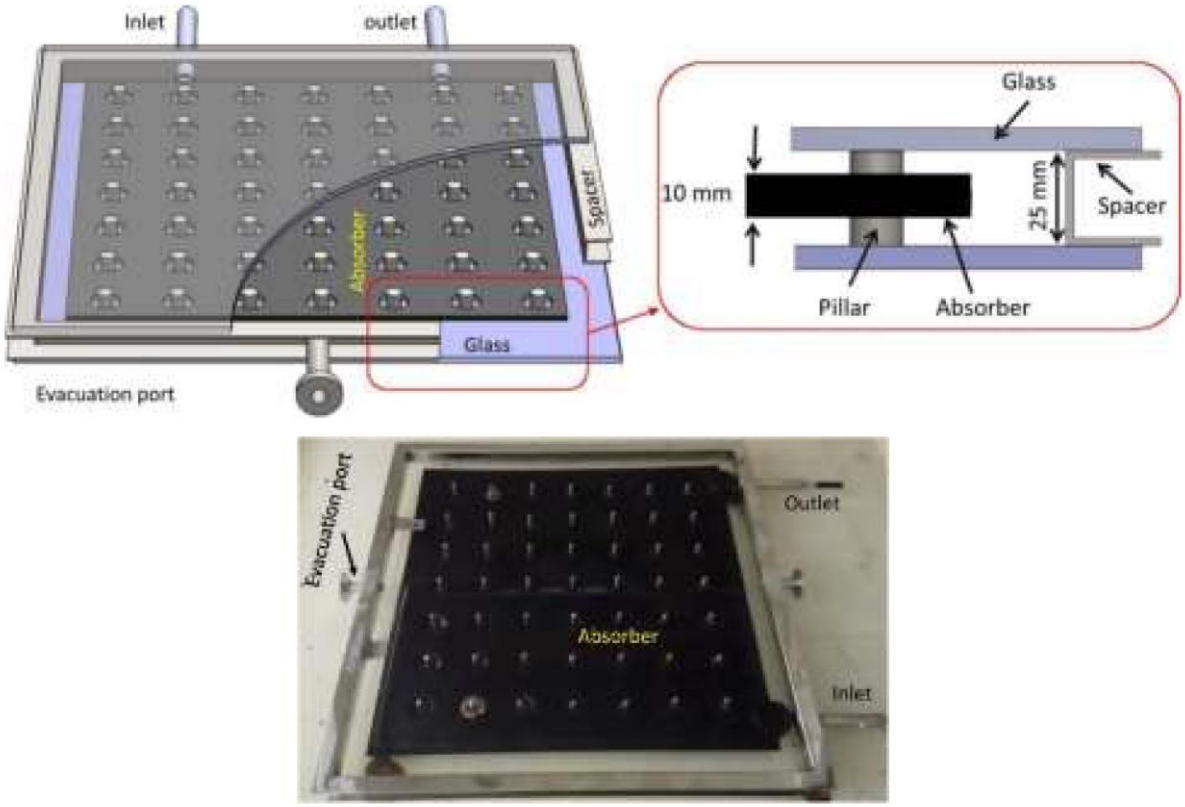


Figure 6-41. Vacuum Flat Plate Collectors

The sealing must be mechanically strong and air-tight in order to ensure the durability of the internal vacuum during the life of the collector, and this is also the main challenge in the manufacture of vacuum plate solar collectors.

Unit based on VPFC technology of producer TVP Solar, which has tackled challenge of ensuring the durability of the internal vacuum during the life of the collector, will be used in scenario development and is further analysed in the following subchapter.

6.2.2.7 CF (type 3) - TVP Solar MT-Power High-Vacuum Flat Plate Collectors (HVFPC)

Swiss manufacturer of solar collectors, TVP Solar has developed a set of technologies called Thermal Vacuum Power Charged™. This title covers the design, manufacture, maintenance and supervision of high vacuum (10-9 mbar) for MT-Power v4.3 collectors. The reason for using vacuum in these plate collectors is the fact that vacuum is one of the best thermal insulators, which minimizes all heat losses due to convection.



Figure 6-42. Flexible inorganic glass-metal seal

The use of innovative materials such as a flexible inorganic glass-metal seal (Figure 6-42) and sorption pumps for vacuum maintenance, as well as a special production system, makes it possible to withstand large mechanical loads that ensure the stability of the vacuum in solar collectors for a period of 25 years.

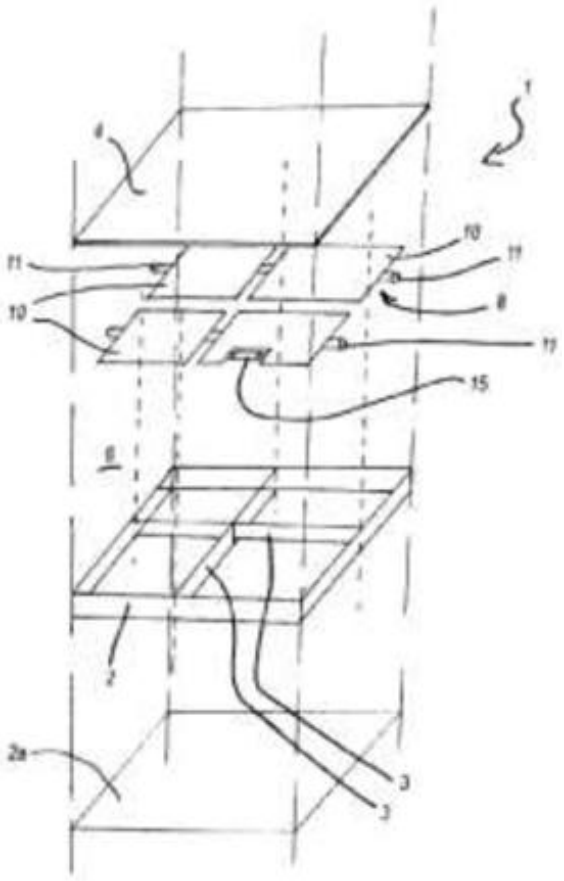


Figure 6-43. Cross section of TVP Solar high-vacuum plate solar collector (1) solar collector, (2) frame, (3) spacers, (4) glass cover, (6) closed chamber, (8) absorber, (15) sorption vacuum pump

In addition, the patented vacuum control system (Spot-Check) provides information on the quality of the vacuum inside the solar collectors to facilitate maintenance and ensure normal functionality throughout the equipment's lifetime.



Figure 6-44. Vacuum control system (Spot-Check)

High-Vacuum Flat Plate Collector (HVFPC) MT-Power v4.3 represents the latest generation of high-vacuum flat plate solar collectors manufactured by TVP Solar. This type of collector uses the previously described Thermal Vacuum Power Charged technology and has a Solar Keymark certificate up to 200°C.

With its design and functionality, this type of collector has been developed for the production of renewable thermal energy and application in plants where media temperatures between 65°C and

180°C are required, such as DHS, industrial processes, agricultural greenhouses, desalination plants and solar cooling systems.

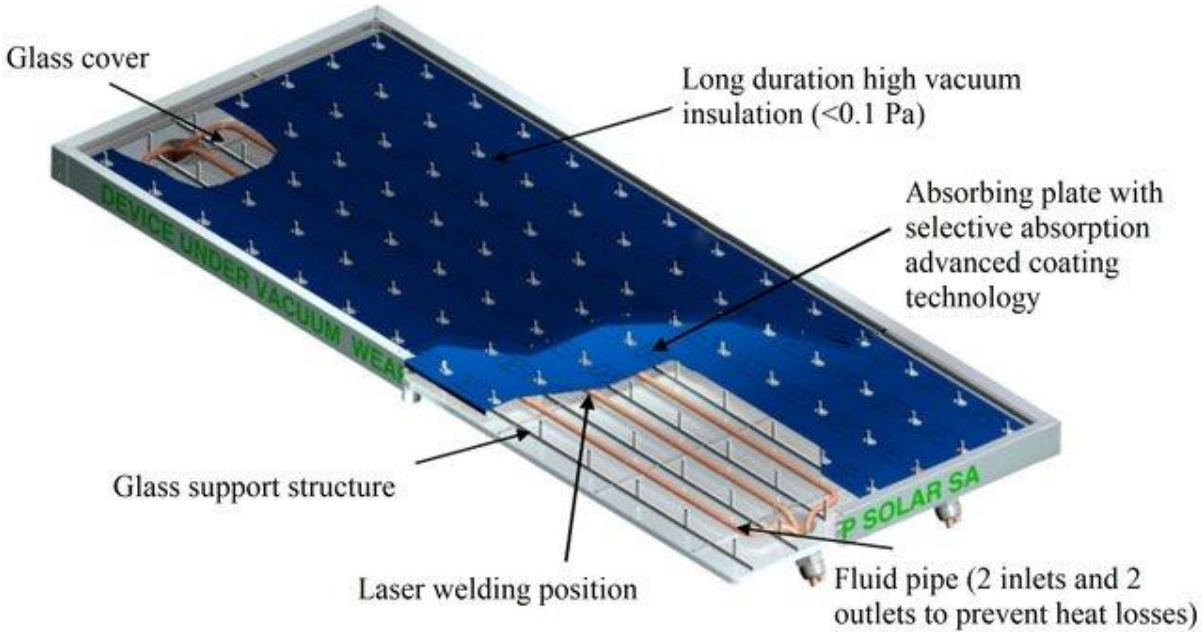


Figure 6-45. Flat plate high-vacuum solar panel construction

The main characteristics of the collector:

- The choice of flat plate dimensions in order to maximize active surface
- Using a vacuum to reduce heat losses and increase performance
- Integrated return loop to reduce heat losses and increase modularity, i.e. the independence of each solar collector
- Metal housing with anti-corrosion protection for durability in all types of environments
- Collectors do not require precise cleaning or additional parts
- There is no decline in the efficiency of solar thermal energy production throughout the equipment's working life
- Integration of the Spot-Check system for simple vacuum quality control
- All parts of solar collectors can be recycled and reused.

Technical characteristics of considered TVP Solar MT-Power HVFPC are shown in following table.

Table 6-17. Technical characteristics TVP MT Power HVFPC

Technical characteristics	
Dimensions (L x W x H)	975 x 2014 x 51(115) mm
Gross surface	1.96 m2
Aperture surface	1.84 m2
Mass	53 kg
Volume fluid	1.4 l
Material absorber and pipes	aluminum plate / copper tube
Absorber coating	Alanod Mirotherm ®
Material of plates	AISI 441 stainless steel
Glass coating	unilateral antireflective (internal)
Connection	SMS PN16
Operating conditions	

Temperature stagnation	302 °C
Max. operating pressure	16 bars
Pressure drop (water, at 260 l/h and 50 °C)	1.4 kPa
Power	1.200 kWh/m2

The considered configuration and integration of solar collectors in DHS is shown in Figure 6-46. When sunlight strikes the surface of the collectors, the absorbers capture this energy and transfer it to the working fluid. This fluid circulates through a closed piping system within the solar collectors, gradually heating up and transferring the thermal energy further into the system. The heat from the medium is then transferred to a heat exchanger, where the energy is passed on to the water circulating within the district heating network. Thus, the solar heating plant functions as a separate closed loop that is indirectly, through a heat exchanger, connected to the system to which it supplies thermal energy. Therefore, there is no direct connection between the heating medium that flows inside the solar field and the medium in the system to which the thermal energy is transferred. In terms of heat energy production, the solar collector system provides heat at a constant temperature through a control and monitoring system that manages variable flow pumps. The heating medium in solar thermal systems can be demineralized water, a mixture of water and glycol (for protection against freezing) or thermal oil. The solar heating plant is equipped with safety systems that include coolers, valves and expansion vessels to avoid overheating of the medium inside the closed loop in any situation.

The overall efficiency of solar collector systems and required number of solar collectors in the solar collector field depends on several key factors. First, geographical location plays a crucial role, as regions with higher levels of solar radiation allow for greater system efficiency. Then, the orientation and tilt of the collectors must be optimized to capture the maximum amount of solar energy. Additionally, the system sizing must be tailored to the user's needs, considering the size of the network and seasonal fluctuations in heat demand.

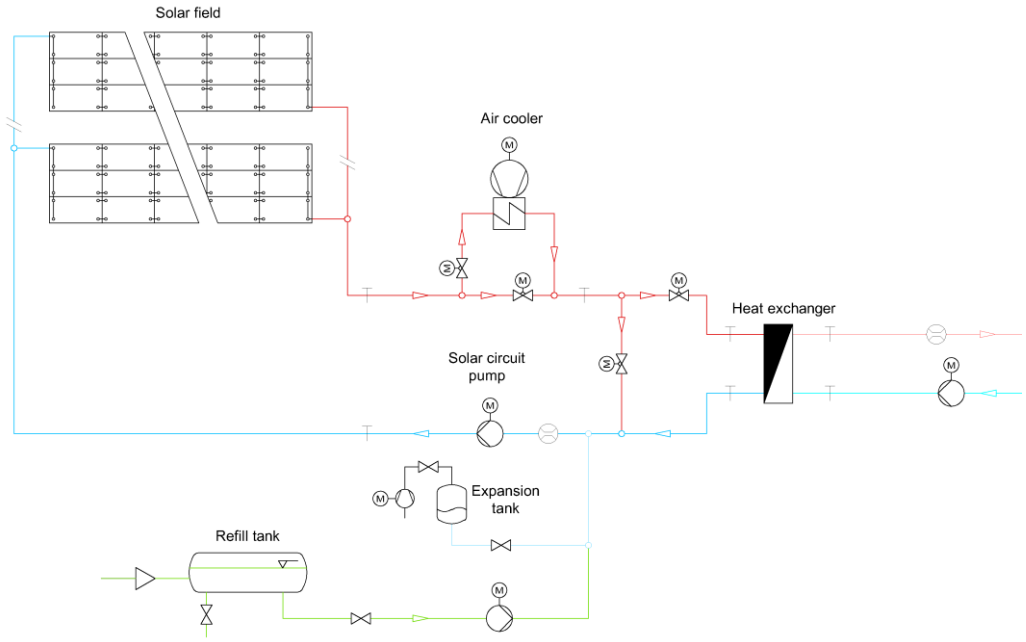


Figure 6-46. Basic scheme of integration of solar thermal system in DHS

The system is designed to work in conjunction with other energy sources. Integration of solar collectors along other heat sources increases the reliability of heat supply, decreases operating costs and emissions.

Many solar collector systems are equipped with thermal storage tanks. These tanks enable the storage of excess heat generated during the day, meaning that the produced energy can be used later when solar radiation is weak or non-existent. This increases operational flexibility and allows for a more stable energy supply, reducing dependence on immediate production.

Once the system is properly designed and implemented, solar collectors can significantly contribute to reducing fossil fuel consumption, leading to lower operational costs and reduced greenhouse gas emissions. In addition to offering economic benefits through energy cost savings, these systems also provide greater energy security by reducing reliance on external energy sources. This enables a long-term sustainable solution for district heating, particularly in the context of the global shift towards renewable energy sources and reducing environmental impact.

Overall technical characteristics of CF (type 3) configuration is given in following table:

Table 6-18. Technical characteristics of the Solar collector-based plant

Solar collectors	Unit	CF
Solar collector type	-	High-Vacuum Flat Plate Collector (HVFPC)
Manufacturer	-	TVP Solar
Solar collector model	-	MT-Power v4.3
Aperture surface	m^2	1.84
Media temperature range	°C	Up to 200
Max operating pressure	bar	16
Power	kwh/m2	650

Location of the Solar DH plant

A potential location for the solar filed was provided by Termoelectrica, and its situated 500 meters from the CHP Source 1 location, in the Colonita street (coordinates 47°02'06.0"N 28°54'21.6"E). It is a plot of it is a plot of **4 ha** in size with elevation of 69 meters above sea level.



Figure 6-47. Indicative location of solar collector field

On the basis of available area for solar array, taking into account size of solar panels, the supporting structure used and the inclination of the panels and possible shading, it is possible to install **10,626 collectors** with overall **heat output of 14 MW$_t$**.

Due to proximity to CHP Source 1, solar field can be directly connected to CHP Source 1 infrastructure.

Plant operation regimes and connection points within the scope of construction of a new solar thermal power plant

The solar heating plant functions as a separate closed loop that is indirectly, through a heat exchanger, connected to the system to which it supplies thermal energy, in this case the future central heating system (CTS) via CHP Source 1 district heating plant. Therefore, there is no direct connection between the heating medium that flows inside the solar field and the medium in the system to which the thermal energy is transferred. In terms of heat energy production, the solar collector system provides heat at a constant temperature through a control and monitoring system that manages variable (variable) flow pumps. The heating medium in solar thermal systems can be demineralized water, a mixture of water and glycol (for protection against freezing) or thermal (hot) oil. Preparation of the working medium can be performed on site or pre-filling can be done with a previously prepared medium, depending on solution, heating media preparation facility could be built on site or in remote location. The solar heating plant is equipped with safety systems that include coolers, valves and expansion vessels to avoid overheating of the medium inside the closed loop in any situation.

In order to prevent freezing of the heating medium of the solar circuit during cold nights or cold days with very low solar radiation, automatic anti-freezing protocols must be implemented (when the heating medium of the solar circuit is water). When the outside temperature falls below a certain threshold, the solar circuit pump should be activated, circulating the heating medium at a pre-set minimum flow to prevent the water inside the circuit from freezing. If the temperature of the heating medium in the solar circuit falls below 4 °C, heat will be taken from the CTS network to maintain the temperature of the heating medium of the solar circuit above this threshold. This minimum heat is sufficient to prevent freezing. The operational logic is based on temperature and time, with regular temperature checks at certain intervals, ensuring minimal heat consumption from the CTS network

For this purpose, it is necessary to build a connecting heat pipe between the solar field and CHP Source 1, which will be connected in CHP Source 1 to the existing hot water distributor and collector, after 1st stage pumps – Figure 6-48. In this way, the solar field serves to preheat the return water from DHS before CHP plant, ensuring the minimum possible input temperature for the solar field and, thus, the highest efficiency.

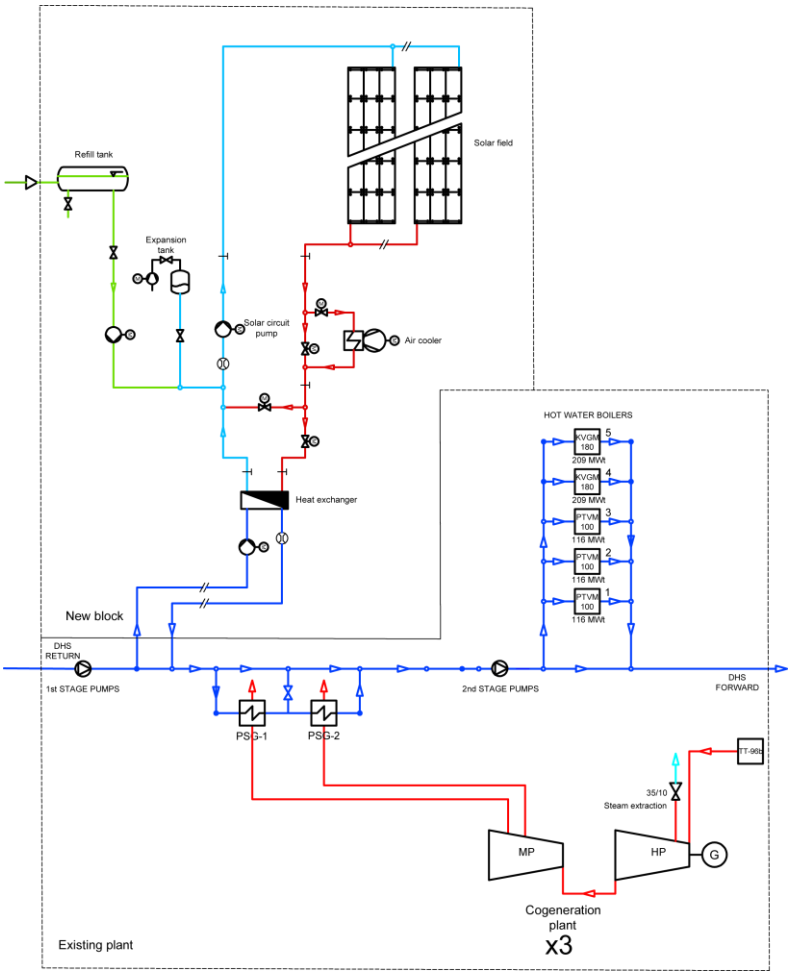


Figure 6-48. Connection to CHP source 1 and DHS

6.2.2.8 Electric Hot Water Boilers

To ensure security of heat supply and enable the use of renewable electricity in heat production, as well as enable demand response and utilisation of cheap electricity in certain hours, the hot water

production via electric boilers is analysed. Thus, in modern market conditions, a possible to reduce the operating costs of thermal energy plants that provide heat energy for DHS via (partial) substitution of natural gas with electricity.

There are two types commercially developed electric boilers:

- Conventional: heater elements use electric resistance (like in household water heaters). Typically, electrical resistance heaters are used for smaller devices, up to 1-2 MW of power.
- Electrode heater elements: the water in the boiler is heated system that consists of three-phase electrode, zero electrodes and management screen. Electric current from the electrode is conducted directly through water, which is heated in the process. Electrical current strength is a function active surfaces electrode and electrical conductivity of the water itself. Active surface the electrode can be continuously regulated by the means of regulation screens and their movement, and the power can be regulated from typical 10-20% (depending on size boiler and voltage) up to 100% of nominal strength. Boilers with electrodes are used for larger strength installations and they typically connect on the 10 kV network.

Due to their simple construction, electric boilers are considered extremely reliable and easy to maintain. The start of the boiler is quick, and the regulation is simple. There is no requirement for a fuel injection system or chimney. Operating costs, as expected, mostly depend on the price of electricity. An essential advantage of electric boilers is their suitability for use for regulatory needs of electricity system due to their quick response.

Electric hot water boilers should be constructed in accordance with EN 12953 standards (a series of standards for the design, construction, testing, supervision and operation of electrically heated and directly fired boilers).

The electric hot water boiler consists of an outer and an inner tank, and the output power is directly proportional to the water level in the inner tank. Since the hot water boiler uses chemically prepared water, a circulation circuit of primary water has been implemented between the boiler and the heat exchanger. The boiler also acts as an expansion vessel for the primary water circuit.

One version of the boiler is used when the minimum load should be low, with a high regulation speed. The load range is then 0 - 100%, and the boiler can be on standby with the main switch on, without mains power. The boiler is supplied with high-resistance earthing or directly earthed zero point.



Figure 6-49. Electric hot water boiler, regulation by changing the water level

There is also a different version. The same water is continuously used in the circulation circuit of the boiler, so the conductivity of the water does not change and there is no need for *blow - down.* This design of boilers has 1-2 electrodes per phase. Power management is done by changing the position of the screens covering the electrodes. At maximum covering of the electrodes, the power of the

boiler is minimal. The control range for this performance is 8-100% of maximum power, and the regulation time from minimum to maximum is about three minutes.

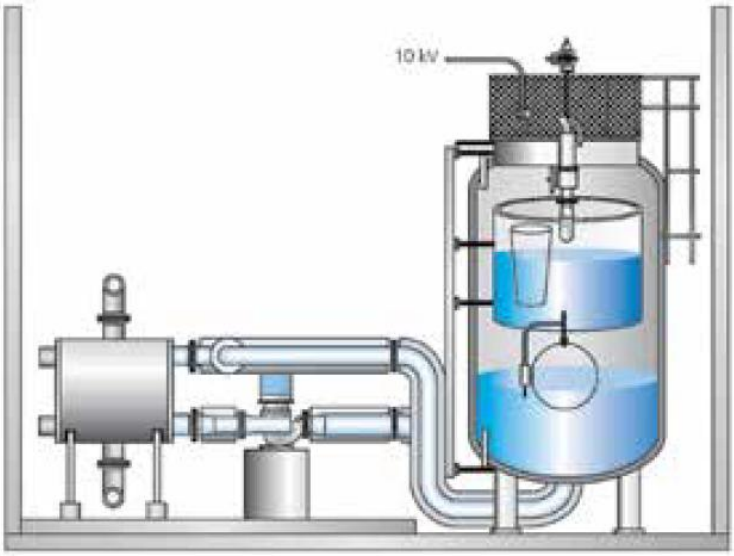


Figure 6-50. Electric hot water boiler with pump and exchanger, regulation with screens

The main equipment of a hot water boiler basically includes a pressure vessel, a protective boiler cage, and all internal equipment, while auxiliary systems include:

- armature
    - circulation pumps with motor, with all needed equipment
    - primary circuit and hot water exchangers, with all needed equipment
    - dosing pumps with motor and all needed equipment
    - control valves
    - shut-off valves with armatures
- feed water system - tank with degasser, chemical preparation of water, fittings
    - Instrumentation for monitoring and management: temperature and pressure sensors, valves, safety valves and other safety equipment according to appropriate standards
- control cabinet, with appropriate connections, power system, fuses and distribution, and with PLC controllers, safety circuits and appropriate interfaces.

The compact dimensions of the electric boilers, the absence of connection to the chimney and the execution of the fuel supply system enable flexibility in choosing the location.

The hot water boiler is connected to the hot water heating system via the primary/heating water exchanger. In principle, the heat exchanger is built directly next to the boiler, with the option of extending the connecting pipeline to the boiler, to enable accommodation according to the needs of the space. On the primary side is a boiler water circuit, and a DH network circuit on the secondary side.

The size of the connection is determined by the flow rate through the exchanger. If necessary, connection of two exchangers in parallel can be made with appropriate fittings to ensure a higher flow rate.

Unit based on this technology will be used in scenario development and is further analysed in the following subchapter.

6.2.2.9 CF (type 4) - Electric hot water boiler with electrode heater elements

This system utilizes a series of electric hot water boilers, each with a thermal output capacity of 40 megawatts thermal (MW_t). Up to 10 boilers can be installed, providing a total capacity of 400 MWt. The process focuses on the direct heating of water and the subsequent transfer of this heat to a district heating system.

In the electric hot water boilers, water is heated using electrode heater elements located within the boiler. As electric current from the electrodes is conducted directly through water, the water is heated in the process, rapidly raising its temperature to the required level for the heating system.

Once heated, the hot water flows through a heat exchanger. In the heat exchanger, the thermal energy from the hot water is transferred to the district heating network. This process allows the efficient utilization of the produced thermal energy, supplying heat to residential or industrial buildings through the district heating system.

After transferring its heat in the heat exchanger, the cooled water is recirculated back to the boiler, where it is reheated, ensuring a continuous cycle of heating and heat transfer. This closed-loop system maintains a steady supply of thermal energy, optimizing the use of electrical input and maximizing the efficiency of the heating process.

The heated water, having released its thermal energy through the heat exchanger, is returned to the boiler for reheating. This cycle is tightly controlled by advanced monitoring systems that regulate water temperature and flow rates to ensure the consistent delivery of heat. Temperature sensors and control valves play a crucial role in adjusting the flow and maintaining optimal conditions, ensuring that the thermal output aligns with the demand from the district heating system.

This setup allows for precise control over the heating process, enabling rapid response to changes in heating demand and ensuring high operational efficiency. By directly converting electrical energy into thermal energy and transferring it effectively through the heat exchanger, electric hot water boilers provide a reliable and sustainable solution for district heating applications. Their operation does not involve combustion, thus reducing emissions and contributing to a more sustainable energy infrastructure.

By leveraging electric energy for water heating and employing efficient heat exchange techniques, this system maximizes thermal output and minimizes energy losses, making it a versatile and effective solution for modern district heating needs.

40 MWe (max)
3,4 MWe (min)
Efficinency: 99%

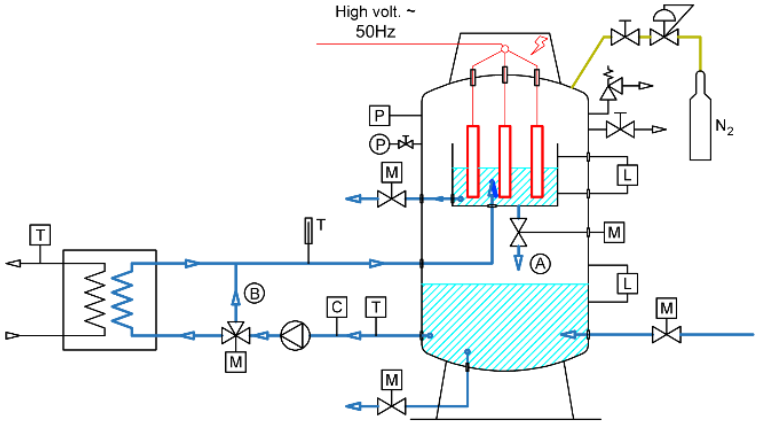


Figure 6-51. Electric hot water boiler

Overall technical characteristics of CF (type 4) configuration is given in following table:

Table 6-19. Technical characteristics of the hot water boiler plant

Hot water boiler	Unit	CF (type 4)
Hot water boiler type	-	Hot water boiler with electrode heater elements
Thermal capacity per boiler (maximum)	MW	40
Thermal capacity per boiler (minimum)	MW	0.34
Outlet temperature	°C	100
Efficiency	%	99
Max operating pressure	bar	16

In analysis of alternatives, array of **4 hot water boilers** will be analysed, with overall **heat output of 140 MW**.

Plant connection points within the scope of construction of a new electric hot water boiler

As Electric hot water boiler (EHWB) will be situated on the CHP Source 1 site, it will be integrated into existing infrastructure.

Electric hot water boilers will be used only when the market price of electricity is lower than the market price of natural gas. These boilers offer several advantages, including high efficiency, low maintenance, and zero direct emissions, making them an environmentally friendly option. Additionally, they provide operational flexibility, allowing facilities to optimize energy costs by switching to electricity during periods of low prices while maintaining a reliable hot water supply.

The new block will be connected to the existing electric infrastructure of the CHP Source 1, which is connected to the Straseni substation via the existing 25 kilometres of triple 110 kV transmission lines owned and operated by Premier Energy, using its own transformers and a new switchgear.

The connection of the new unit to the system for heating of DHS water will be carried out in parallel with the existing hot water boilers at CHP Source 1, as it is shown in Figure 6-52. In this context, it will be necessary to carry out an appropriate reconstruction of the system, because the pipes are relatively large dimensions, the placement of which can represent a certain problem.

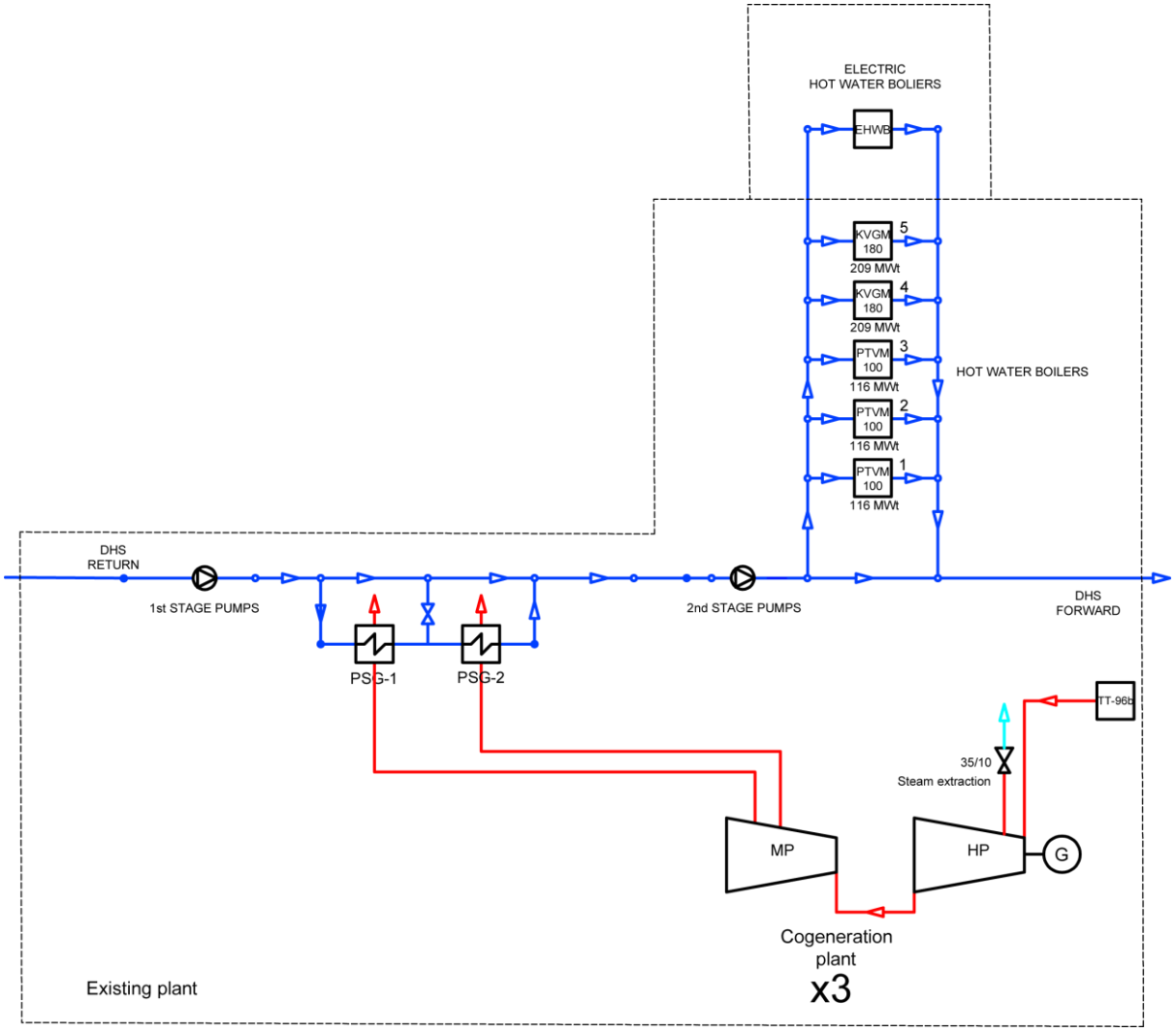


Figure 6-52. Connection to CHP Source 1 and DHS

6.2.2.10 Thermal Energy Storage

Thermal Energy Storage (TES) or heat accumulator **systems play a key role in improving the efficiency and flexibility of district heating networks.** By storing surplus thermal energy generated during periods of low demand, sufficient energy can be ensured during peak consumption times. This approach enhances the reliability and adaptability of the entire heating network.

Heat accumulators are relatively simple devices that can be described as large hot water tanks that are installed in centralized heating systems.

Heat accumulators can be of atmospheric or pressure type. Large heat accumulators are usually built as atmospheric accumulators. In other words, the pressure in the tank above the waterline is approximately equal to the atmospheric pressure. Furthermore, the construction of such accumulators is such that the accumulator is always full of water, so it is never emptied, and only the ratio of the amounts of hot and cold water changes. Thus, hot water entering the TES (charging it) displaces the same amount of cold water from the TES, whereby the boundary layer between the hot and cold water zones moves downwards. When the TES is discharged, the situation is reversed. The cold water enters the accumulator and pushes the hot water out of it, whereby the boundary layer between the hot and cold water zones moves upwards (Figure 6-53).

If the vertical distribution of temperatures in the heat accumulator is observed (see Figure 6-53), as many as six clearly visible layers can be observed:

- lower protective layer,
- a layer of cold water,
- boundary layer,
- a layer of warm water,
- upper protective layer i
- vapor layer.

The lower protective layer for its primary function prevents the transfer of heat by convention towards the bottom of the container. A lower diffuser is located above the protective layer, which allows the water to be evenly distributed inside the heat accumulator without too much mixing along the vertical axis. The boundary layer separates the cold water layer and the warm water layer. Between the layer of hot water and the upper protective layer, there is an upper diffuser which, like the lower diffuser, enables an even horizontal distribution of water inside the heat accumulator without too much mixing along the vertical axis. The upper protective layer has a similar role as the lower protective layer, acting as a thermal insulator towards the vapor layer on top of the heat accumulator. The function of the vapor layer is to prevent oxygen from the air from dissolving in the water of the TES.

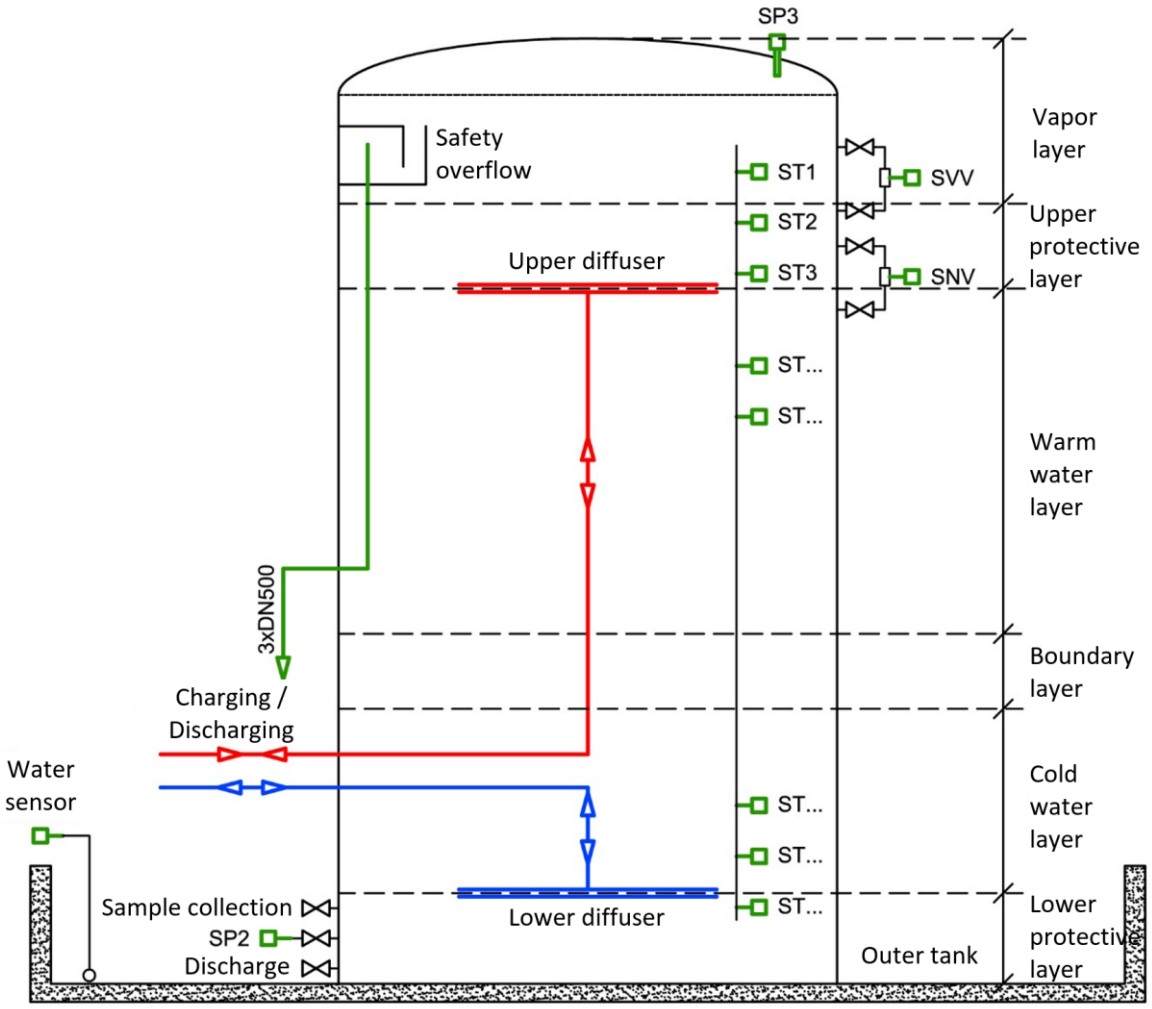


Figure 6-53. Simplified diagram of the TES

The principle of operation of the heat accumulator implies two completely separate modes of operation. When charging, the accumulator *de facto* behaves as a consumer of heat energy, which is why the production units in the accumulator charging mode must produce an increased amount of heat energy. On the other hand, in the discharge mode, the accumulator behaves as a heat source (additional production unit in the system), which is why the other production units in the system can produce less thermal energy. As in the case of charging the battery, the mass balance is always identical from the point of view of the end user, and the end users do not see a difference in the operation of the system with or without a battery. In order for this kind of dual operation mode of the TES to be implemented in practice, **the TES needs to be integrated into the system in parallel with the production units that supply it with thermal energy, i.e. whose operation in the discharge mode it substitutes.**

Unit based on this technology will be used in scenario development and is further analysed in the following subchapter.

6.2.2.11 CF (type 5) - Atmospheric weekly TES

For this project, a weekly TES system is being considered, designed to balance fluctuations in heat production and consumption over a typical week. Taking into consideration analysis of heat demand and the production, the proposed TES system is planned to have a capacity of approximately **1,200**

MWh and a charging/discharging power of **125 MW** which should be adequate to meet heating demands throughout the week. This capacity enables the system to store and release thermal energy as required, ensuring system stability even when demand fluctuates.

The TES will consist of a water-based accumulator housed within a well-insulated steel tank. Insulation is crucial to minimize thermal losses over time. The tank is expected to have dimensions of **41 meters** in height and **22 meters** in diameter, optimized to maximize storage capacity while efficiently utilizing available space. It will be strategically located by the main heat production facility to facilitate seamless integration with the district heating network, ensuring efficient transfer of thermal energy to and from storage.

Depending on position, excess thermal energy from local CHP units, waste-to-energy facilities, heat pumps or solar collectors will be transferred to the TES unit via a heat exchanger and stored as hot water. During periods of high demand, the stored thermal energy will be released back into the network, assisting in maintaining a steady supply without the need for immediate additional heat generation.

The primary advantage of incorporating a TES system is the enhancement of the overall efficiency of the heating network. By storing thermal energy generated during off-peak periods for use during peak demand, fuel consumption and CO_2 emissions can be reduced. This approach not only benefits the environment but also lowers operational costs. Furthermore, the TES system provides increased flexibility, enabling the network to respond rapidly to changes in demand.

Overall technical characteristics of CF (type 5) configuration is given in following table:

Table 6-20. Technical characteristics of TES

TES	Unit	CF (type 5)
TES type	-	Atmospheric weekly
TES capacity	MWh	1,200
Charging/discharging power	MW	125
Outlet temperature	°C	Up to 98

Location of the TES

In order for this, described, kind of dual operation mode of the TES to be implemented in practice, the TES needs to be integrated into the system in parallel with the production units that supply it with thermal energy, i.e. whose operation in the discharge mode it substitutes. Thus, it needs to be situated in CHP Source 1 area and integrated in its system in parallel with production blocks.

Plant connection points within the scope of construction of a new TES

As thermal energy storage (TES) will be situated on the CHP Source 1 site, it will be integrated into existing infrastructure.

The connection of the new unit to the thermal system of the plant and DH network will be carried out in parallel with the existing CHP blocks, where one inlet/outlet connection will be connected to DHS return line in front of 1st stage pumps, and second inlet/outlet connection just in front of 2nd stage pumps. This way, it enables charging/discharging TES using all heat generating facilities connected between those two points. Also, to enable use of energy from hot water boilers for charging of TES, additional connection needs to be carried out which will tap in into the return boiler line to DH line. Proposed connection of TES is shown in Figure 6-54.

In this context, it will be necessary to carry out an appropriate reconstruction of the existing system, because the pipes are relatively large dimensions, the placement of which can represent a certain problem.

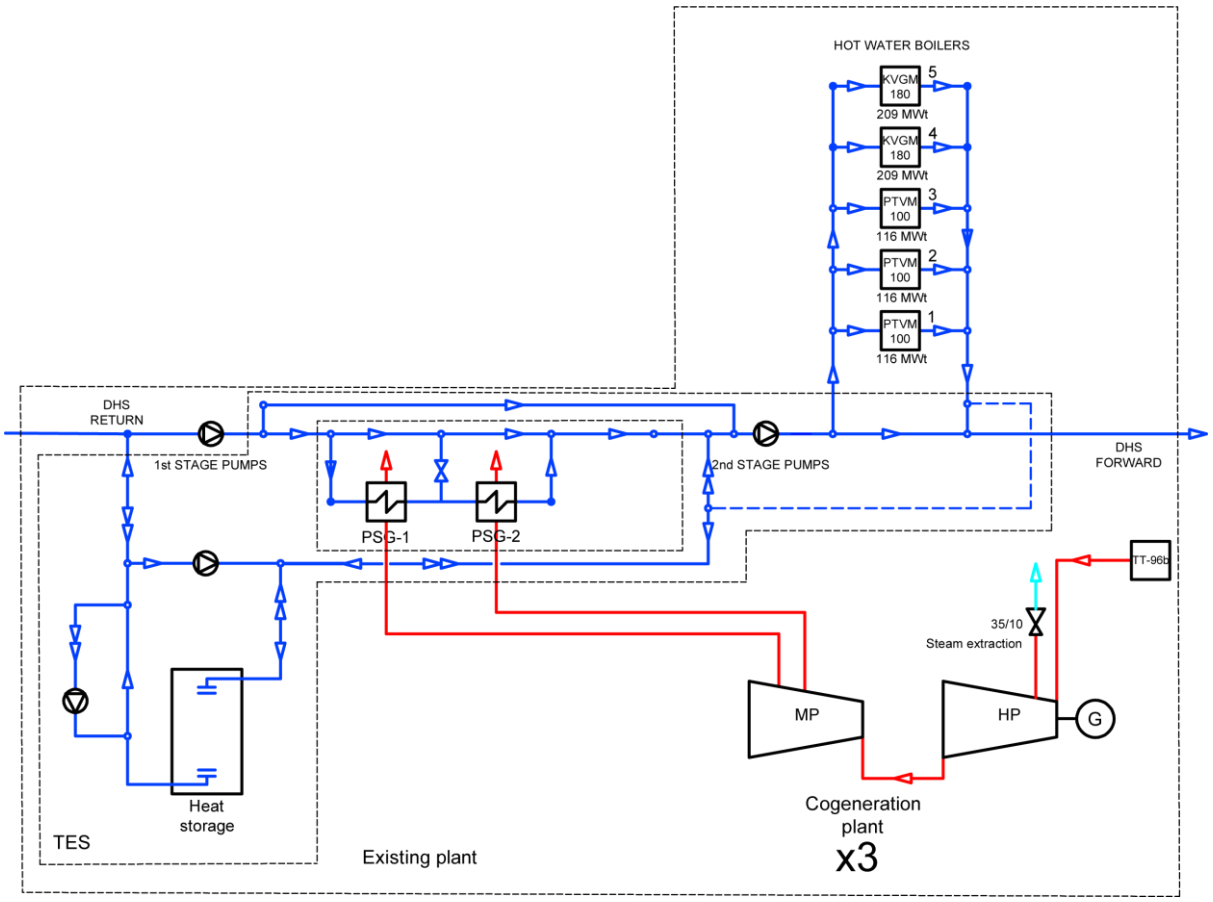


Figure 6-54. Connection to CHP Source 1 and DHS

6.2.3 Combination of technologies of proposed alternatives for detailed economic and financial assessment

This chapter is dedicated to the analysis of selected energy system variants identified as the most suitable for further techno-economic evaluation. To ensure the optimal solution for district heating, the chosen variants are based on various technologies and configurations that offer high energy efficiency, operational flexibility and environmental sustainability.

During the selection process, special attention was given to the potential for reducing operational costs and emissions, as well as the ability of the systems to adapt to changes in energy demand. The considered variants include combined heat and power systems with gas turbines, gas engineswaste-to-energy conversion systems, solar collectors, heat pumps, electric boilers and thermal energy storage systems. Each of these variants provides specific advantages in terms of energy efficiency and sustainability and thus have been singled out for more detailed analysis.

The considered scenario variants include **CHP power system with gas turbines** / **gas engines** as major production units which will cover majority of energy needs of the future system and **complementary units** that are considered for investment in the future to meet specific national and/or local goals and encompass RES, such as waste-to-energy conversion systems, solar collectors, heat pumps, electric boilers and thermal energy storage systems. Each of these variants provides specific advantages in terms of energy efficiency and sustainability and thus have been

singled out for more detailed analysis. All the considered technologies are, in more details, described in Chapter 6.

In the study, 6 different variants of the construction of new production units were analysed and compared. The scenarios are designed to cover existing and future energy needs by taking into account previously identified energy demand, capacity performance metrics for existing and future production units, characteristics of available fuels, local waste generation, geographical location and corresponding solar insolation.

Table 6-21. Nominal technical data for selected scenarios based on heat demand in 2030.

Variant		Number of units	Maximum thermal output	Maximum electrical output	Efficiency (CHP)	Electrical efficiency	Energy source
			MWh/h	MWh/h	%	%	
A	CHP type 1	2 x SGT800 + 2 x HRSB + ST	116.0	170.0	86.58	50.94	Natural gas
	Waste to Energy	1	54.0	19.75	61.96	15.47	Waste
	Solar collectors		14.0				Solar radiation
	Heat pumps	1	20.0				Waste water energy
	Electric boilers	1	40.0				Electricity
B	CHP type 2	3 x SGT800 + 3 x HRSB + ST	174.0	250.0	86.76	51.02	Natural gas
	Waste to Energy	1	54.0	19.75	61.96	15.47	Waste
	Solar collectors		14.0				Solar radiation
	Heat pumps	1	20.0				Waste water energy
	Electric boilers	1	40.0				Electricity
C	CHP type 3	1 x GT 9G.04 + 1 x HRSB + ST	260.0	440.0	88.58	53.87	Natural gas
	Waste to Energy	1	54.0	19.75	61.96	15.47	Waste
	Solar collectors		14.0				Solar radiation
	Heat pumps	1	20.0				Waste water energy
	Electric boilers	1	40.0				Electricity
D	CHP type 4	3 x GT LM6000 + 3 x HRB	174.0	162.0	80.31	38.48	Natural gas
	Waste to Energy	1	54.0	19.75	61.96	15.47	Waste
	Solar collectors		14.0				Solar radiation

Variant		Number of units	Maximum thermal output	Maximum electrical output	Efficiency (CHP)	Electrical efficiency	Energy source
			MWh/h	MWh/h	%	%	
	Heat pumps	1	20.0				Waste water energy
	Electric boilers	1	40.0				Electricity
E	CHP type 5	18 Gas engines Jenbacher J920 FleXtra	184.0	192.6	93.8	47.4	Natural gas
	Waste to Energy	1	54.0	19.75	61.96	15.47	Waste
	Solar collectors		14.0				Solar radiation
	Heat pumps	1	20.0				Waste water energy
	Electric boilers	1	40.0				Electricity
F	Waste to Energy	2	108.0	39.5	68.01	14.57	Waste
	Solar collectors		14.0				Solar radiation
	Heat pumps	5	100.0				Waste water energy
	Electric boilers	4	160.0				Electricity

Each of these variants provides specific advantages in terms of energy efficiency and sustainability and thus have been singled out for more detailed analysis.

To provide a clear insight into the reasons for selecting each variant, technical and economic benefits, as well as potential challenges are highlighted. To select the most suitable options for further techno-economic analysis of the heating system, it is necessary to define the criteria upon which each system will be evaluated. Each criterion is important for understanding the system's performance, reliability, and sustainability and facilitates decision-making regarding long-term cost-effectiveness and environmental impact. Below is a description of each criterion, along with the variant that proved to be the best according to that criterion:

- **Overall efficiency** measures how effectively a system converts fuel into useful energy, whether in the form of heat or electricity. Higher efficiency means that the system makes better use of the energy from fuel, which reduces losses and, in the long run, leads to better results in terms of costs and emissions. The highest overall efficiency is achieved by variant **C**.
- **Electrical efficiency** refers to how successfully a system converts fuel into electrical energy. This criterion is particularly important for systems that generate a significant amount of electricity, as increasing this efficiency directly impacts the reduction of fuel consumption and costs. The highest electrical efficiency is achieved by variant **C**.
- **Peak electrical power** describes the maximum electrical power a system can produce during peak demand periods. The system's flexibility to meet these peak demands allows for a more stable supply and better grid management without the need for additional capacity. The variant with the maximum electrical output is variant **C**.

- **Fuel flexibility -** Systems capable of utilizing multiple fuel types allow for flexibility depending on fuel availability and price fluctuations. The use of alternative fuels, such as biomass or waste, helps reduce costs and decreases reliance on a single energy source, thereby increasing the system's flexibility and resilience. All variants utilize a variety of energy sources including natural gas, municipal and industrial waste, solar energy and low-temperature heat from the ground.
- **Share of RES in heat supply** - The use of renewable energy sources, such as solar collectors or biomass, in heat supply reduces fossil fuel consumption and greenhouse gas emissions. A higher share of renewable sources in the system contributes to sustainability and reduces environmental impact. The highest use of renewable energy sources is in variant **F**.

The description of selected scenarios and energy model results for the year 2030 are given in following subchapters.

6.2.3.1 A - CHP (type 1) [2 x SGT800 + 2 x HRSB + ST] + WtE + Solar collectors + Heat pumps + Electric boilers + Heat storage (TES)

Analysed Scenario A consists of:

- CHP type 1 unit consisting of two Siemens SGT800 natural gas powered gas turbines connected to two dual-pressure Heat Recovery Steam Boilers and a back-pressure steam turbine with overall installed capacity of 116 MW_t and 170 MW_e.
- Stationary (bubbling) fluidised bed Waste-to-energy plant with overall installed capacity of 54 MW_t and 19.75 MW_e.
- Solar collector field with overall capacity of 14 MW_t.
- One 20 MW_t two-stage R1234ze water-based heat pump.
- One 40 MW_t electric hot boiler with electrode heating elements.

The CHP system in Scenario A is based on two Siemens SGT800 gas turbines connected to two dual-pressure Heat Recovery Steam Boilers (HRSBs) and one back-pressure steam turbine generator. This system uses natural gas as the primary fuel with the gas turbines combusting the gas to generate electricity. The high-temperature exhaust gases produced during combustion pass through the HRSBs, where the thermal energy is transferred to the water from the feedwater tank.

Within the HRSBs, the system is designed with high-pressure and low-pressure sections that allow for optimal utilization of the available thermal energy. The produced steam then enters the back-pressure steam turbine where it is converted into additional electricity and provides thermal energy for the district heating network. The system is equipped with a dry cooling tower that enables efficient heat dissipation and maintains a high level of efficiency even during periods of reduced heat demand. This configuration allows for the optimal use of natural gas for both electricity and heat production, thereby enhancing the overall energy efficiency of the system.

Solar collectors integrated into this variant utilize solar energy to produce heat that can be used for heating or sanitary water production. Absorbers within the collectors convert solar energy into heat, warming the working fluid which then transfers the heat to the district heating water system. During the day, when solar energy is available, this system reduces the need for other energy sources, thereby lowering operational costs and CO_2 emissions. The solar collectors are connected to a Thermal Energy Storage (TES) system, ensuring maximum utilization of the produced energy.

Heat pumps in Scenario A extract waste water energy and transfer it to a higher temperature level, making it suitable for heating purposes. In this process, the working fluid absorbs heat from a low-grade source, passes through a compressor where its pressure and temperature increase, and then transfers the heat to the water in the heating system. This system enables the efficient use of

renewable energy sources and reduces operating costs, especially during periods of low electricity price and when other energy sources are more expensive or less available.

The Waste-to-Energy (WtE) system in Scenario A harnesses the energy contained in waste as an additional source of heat and electricity. The waste is incinerated in a specialized furnace, releasing heat that is used to produce steam. The generated steam then drives a turbine to generate electricity, while the remaining heat is used to heat water in the district heating system. This process not only reduces the amount of waste ending up in landfills but also contributes to the overall energy efficiency of the system and reduces greenhouse gas emissions.

Electric boilers in this scenario variant provide flexible heat production when needed, particularly during peak load periods or when other energy sources are less available or when the price of electricity is lower than the price of natural gas.. They directly convert electricity into heat and integrate with the rest of the district heating system. Their advantage is the ability to be switched on and off quickly, providing additional flexibility in system operation.

The Thermal Energy Storage (TES) system allows the storage of surplus heat generated during periods of low demand. This stored heat can then be used during peak load periods, ensuring a continuous and stable heat supply. The TES system increases the flexibility and efficiency of the entire system and enables fuel consumption optimization, reducing operational costs and emissions. Heat storage allows the produced energy to be used in the most efficient way, especially when solar collectors, heat pumps, or the WtE system generate more energy than is currently needed.

Energy model results – Scenario A

The mass and energy balance for potential Scenario **A** is presented below.

Table 6-22. The mass and energy balance for Scenario A (Heat and EE production)

Units	Heat production		EE production		EE consumption
	MWh	%	MWh	% (condensing)	MWh
Solar	16.003,66	0,93%			
HOB-West					
Gas Engine (existing HOB-W) – 33 Mwe / 25,8 Gcal/h	162.713,66	9,43%	204.245,73		0,00
Boiler 1 (HOB-W) – 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (HOB-W) – 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 3 (HOB-W) – 100 Gcal/h	0,00	0,00%	-		0,00
Source ½/3					
Gas Engines (existing S3) – 22 Mwe / 17,2 Gcal/h	170.013,18	9,86%	187.429,77		0,00
Electric hot water boilers – 40 Mwe (x1)	28.219,31	1,64%	0,00		-28.504,35
CHP (WtE) [Boiler + ST] (x1)	209.787,79	12,16%	43.599,33		0,00
SIEMENS SHP-C-600 Heat pump – 20 MWt (x1)	75.494,19	4,38%	0,00		-21.665,03
CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]	420.637,76	24,39%	1.371.122,08	51,93%	-19.585,24
Industrial sector (priority)	0,00	0,00%	0,00		0,00
Existing unit at Source 1 / CHP 1 – reconstructed	506.476,72	29,36%	311.858,67		0,00
Existing unit at Source 1 / CHP 2	129.227,86	7,49%	130.779,91		0,00
Existing unit at Source 1 / CHP 3	6.082,79	0,35%	10.945,83		0,00
Boiler 1 (Source 1) – 120 Gcal/h	126,24	0,01%	-		0,00
Boiler 2 (Source 1) – 120 Gcal/h	0,00	0,00%	-		0,00
HOB-South					
No additional units are introduced…	0,00	NA	0,00		0,00
Boiler 1 (HOB-–) - 26 Gcal/h	0,00	NA	-		0,00
Boiler 2 (HOB-–) - 42 Gcal/h	0,00	NA	-		0,00
Boiler 3 (HOB-–) - 70 Gcal/h	0,00	NA	-		0,00
Not Covered	0,00	0,00%	0,00		0,00
TOTAL:	**1.724.783,14**	**100,00%**	**2.259.981,31**		**-69.754,63**

Table 6-23. The mass and energy balance for Scenario A (Fuel consumption and CO2 emission)

Units	Fuel consumption (NG)		CO_2 emission		Efficiency (CHP)	Efficiency (CHP EE)
	MWh	Sm^3 (n. gas)	t w (waste)	t CO_2	%	%
Solar						
HOB-West						
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	429.439,89	45.470.106,12	-	91.900,14	85,45	47,56
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Source 1/2/3						
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	394.083,24	41.726.460,33	-	84.333,81	90,70	47,56
Electric hot water boilers - 40 MWe (x1)	0,00	0,00	0,00	0,00	-	-
CHP (WtE) [Boiler + ST] (x1)	329.103,81	-	98.731,14	23.695,47	76,99	13,25
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	0,00	0,00	0,00	0,00	-	-
CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]	2.634.195,63	278.914.831,02	-	563.717,86	68,02	52,05
Industrial sector (priority)	NA	NA	0,00	NA	NA	NA
Existing unit at Source 1 / CHP 1 - reconstructed	1.389.027,53	147.073.503,48	-	297.251,89	58,91	22,45
Existing unit at Source 1 / CHP 2	487.472,46	51.614.731,41	-	104.319,11	53,34	26,83
Existing unit at Source 1 / CHP 3	37.500,07	3.970.595,33	-	8.025,01	45,41	29,19
Boiler 1 (Source 1) - 120 Gcal/h	126,24	13.366,67	-	27,02	-	-
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
HOB-South						
No additional units are introduced...	0,00	0,00	-	0,00	-	-
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	0,00	-	0,00	-	-
Not Covered						
TOTAL:	**5.700.949**	**568.783.594**		**1.173.270**		
Thermal heat storage (TES) is used	Yes					
Overall energy stored in TES during the year	MWh	104.639,33				

In this case, base heating needs are covered by WtE plant, existing gas engines, heat pumps, solar collectors, and new CHP plant while peak demand is met through currently available CHP units production. . Electric boilers are operating in hours within the year when the selling price of heat surpasses that of electricity.

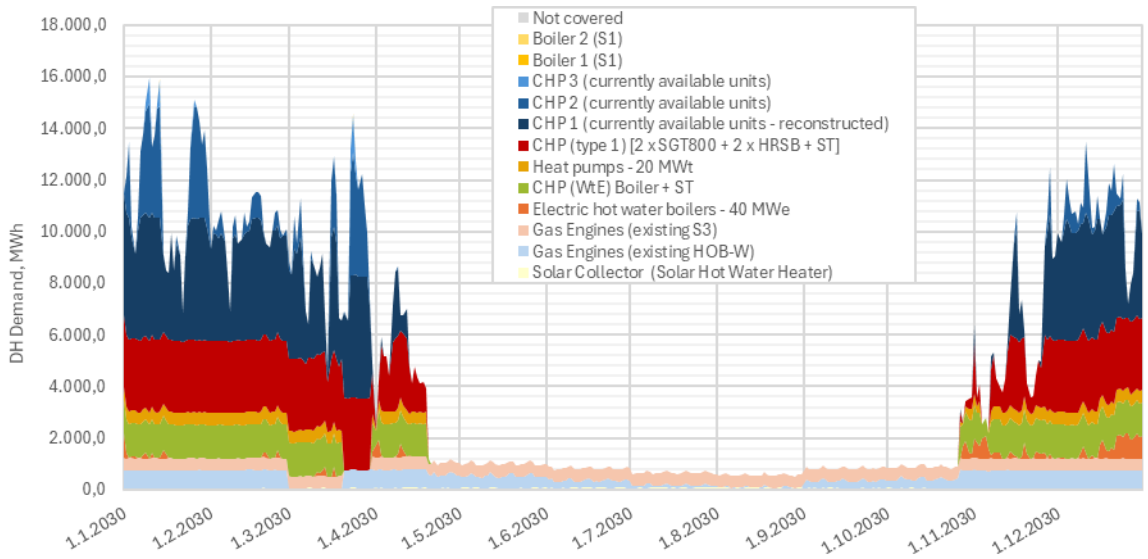


Figure 6-55. DH Demand - Scenario A

6.2.3.2 B - CHP type 2 [3 x SGT800 + 3 x HRSB + ST] + Heat storage (TES) + WtE + Solar collectors + Heat pumps + Electric boilers

Analysed Scenario B consists of:

- CHP type 2 unit consisting of three Siemens SGT800 natural gaspowered gas turbines connected to three dual-pressure Heat Recovery Steam Boilers and a back-pressure steam turbine with overall installed capacity of 174 MW_t and 250 MW_e.
- Stationary (bubbling) fluidised bed Waste-to-energy plant with overall installed capacity of 54 MW_t and 19.75 MW_e.
- Solar collector field with overall capacity of 14 MW_t.
- One 20 MW_t two-stage R1234ze geothermal heat pump.
- One 40 MW_t electric hot boiler with electrode heating elements.

Scenario B is based on a CHP system that uses three Siemens SGT800 gas turbines connected to three dual-pressure Heat Recovery Steam Boilers (HRSBs) and one back-pressure steam turbine generator. This configuration differs from Scenario A by the addition of a third gas turbine and HRSB, allowing for greater overall electricity and heat production.

As in Scenario A, the gas turbines combust natural gas to generate electricity while the high-temperature exhaust gases pass through the HRSBs where thermal energy is transferred to the water from the feedwater tank. Given that Scenario B utilizes three HRSBs, the system can more efficiently harness the available thermal energy and produce more steam that enters the steam turbine.

The back-pressure steam turbine in this configuration also generates additional electricity and provides heat for the district heating network. Thanks to the third gas turbine, the system has greater flexibility and capacity to supply electricity and heat, making it suitable for scenarios with higher energy demands. A dry cooling tower is also integrated into this system, maintaining efficiency across varying levels of heat demand.

As with Scenario A, Scenario B includes solar collectors, heat pumps, a Waste-to-Energy (WtE) system and electric boilers. However, the additional gas turbine provides greater capacity for covering peak loads and contributes to the overall increased energy efficiency of the system.

Energy model results – Scenario B

The mass and energy balance for potential Scenario **B** is presented below.

Table 6-24. The mass and energy balance for Scenario B (Heat and EE production)

Units	Heat production		EE production		EE consumption
	MWh	%	MWh	% (condensing)	MWh
Solar	16.003,66	0,93%			
HOB-West					
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	162.713,66	9,43%	204.245,73		0,00
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Source 1/2/3					
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	170.013,18	9,86%	187.429,77		0,00
Electric hot water boilers - 40 MWe (x1)	28.219,31	1,64%	0,00		-28.504,35
CHP (WtE) [Boiler + ST] (x1)	209.787,79	12,16%	43.599,33		0,00
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	75.494,19	4,38%	0,00		-21.665,03
CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	600.767,64	34,83%	2.112.270,79	51,89%	-30.056,91
Industrial sector (priority)	0,00	0,00%	0,00		0,00
Existing unit at Source 1 / CHP 1 - reconstructed	393.875,28	22,84%	299.459,52		0,00
Existing unit at Source 1 / CHP 2	66.631,65	3,86%	65.330,27		0,00
Existing unit at Source 1 / CHP 3	1.276,81	0,07%	2.610,83		0,00
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
HOB-South					
No additional units are introduced...	0,00	NA	0,00		0,00
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	NA	-		0,00
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	NA	-		0,00
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	NA	-		0,00
Not Covered	0,00	0,00%	0,00		0,00
TOTAL:	**1.724.783,14**	**100,00%**	**2.914.946,24**		**-80.226,29**

Table 6-25. The mass and energy balance for Scenario B (Fuel consumption and CO2 emission)

Units	Fuel consumption (NG)		CO_2 emission		Efficiency (CHP)	Efficiency (CHP EE)
	MWh	Sm^3 (n. gas)	t w (waste)	t CO_2	%	%
Solar						
HOB-West						
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	429.439,89	45.470.106,12	-	91.900,14	85,45	47,56
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Source 1/2/3						
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	394.083,24	41.726.460,33	-	84.333,81	90,70	47,56
Electric hot water boilers - 40 MWe (x1)	0,00	0,00	0,00	0,00	-	-
CHP (WtE) [Boiler + ST] (x1)	329.103,81	-	98.731,14	23.695,47	76,99	13,25
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	0,00	0,00	0,00	0,00	-	-
CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	4.042.623,52	428.042.490,11	-	865.121,43	67,11	52,25
Industrial sector (priority)	NA	NA	0,00	NA	NA	NA
Existing unit at Source 1 / CHP 1 - reconstructed	1.283.293,40	135.878.124,26	-	274.624,79	54,03	23,34
Existing unit at Source 1 / CHP 2	243.314,57	25.762.719,38	-	52.069,32	54,24	26,85
Existing unit at Source 1 / CHP 3	8.858,28	937.936,03	-	1.895,67	43,89	29,47
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
HOB-South						

No additional units are introduced...	0,00	0,00	-	0,00	-	-
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	0,00	-	0,00	-	-
Not Covered						
TOTAL:	**6.730.717**	**677.817.836**		**1.393.642**		

Thermal heat storage (TES) is used	Yes	
Overall energy stored in TES during the year	MWh	104.639,33

In this case, base heating needs are covered by WtE plant, existing gas engines, heat pumps, solar collectors, and new CHP plant while peak demand is met through currently available CHP units production. Electric boilers are operating in hours within the year when the selling price of heat surpasses that of electricity.

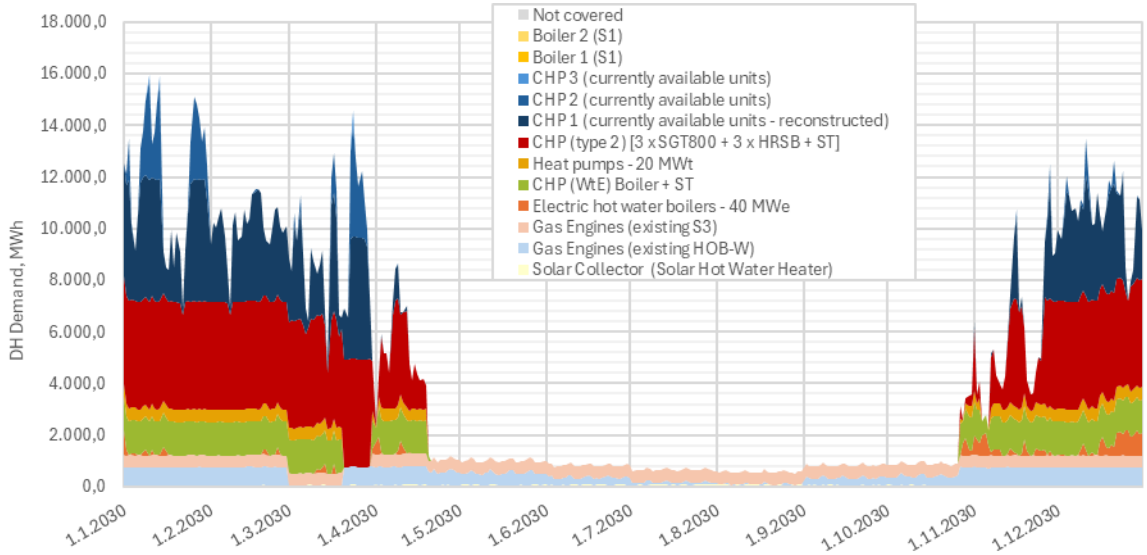


Figure 6-56. DH Demand - Scenario B

6.2.3.3 C - CHP type 3 [1 x GT 9G.04 + 1 x HRSB + ST] + Heat storage (TES) + WtE + Solar collectors + Heat pumps + Electric boilers

Analysed Scenario C consists of:

- CHP type 3 unit consisting of one GT 9G.04 natural gas powered gas turbine connected to dual-pressure Heat Recovery Steam Boilers and a back-pressure steam turbine with overall installed capacity of 260 MW_t and 440 MW_e.
- Stationary (bubbling) fluidised bed Waste-to-energy plant with overall installed capacity of 54 MW_t and 19.75 MW_e.
- Solar collector field with overall capacity of 14 MW_t.
- One 20 MW_t two-stage R1234ze geothermal heat pump.
- One 40 MW_t electric hot boiler with electrode heating elements.

Scenario C utilizes a CHP system consisting of one gas turbine, one dual-pressure Heat Recovery Steam Boiler (HRSB), and one back-pressure steam turbine generator. Unlike Scenarios A and B, Scenario C has a 1x1 configuration, meaning it uses a single, larger and more powerful gas turbine. This configuration enables high efficiency in electricity and heat production, while also being a simpler and more compact system.

The 7HA gas turbine combusts natural gas to generate electricity while the high-temperature exhaust gases pass through the HRSB, where thermal energy is transferred to water. Since the HRSB handles exhaust gases from a more powerful turbine, this system can produce significant amounts of steam that enter the steam turbine. The back-pressure steam turbine then generates additional electricity and thermal energy for the district heating network with the option of using two uncontrolled steam extractions for direct supply to the heating network.

A dry cooling tower ensures efficient heat dissipation, allowing stable system operation regardless of heat demand. Scenario C offers a high level of flexibility in energy production and is suitable for areas with variable demand due to its ability to quickly adapt to load changes.

This scenario also includes solar collectors, heat pumps, a Waste-to-Energy (WtE) system, and electric boilers, enabling diversification of energy sources and increasing the share of renewables in the overall energy mix. Due to the powerful 7HA gas turbine, Scenario C offers a combination of high efficiency and reliability with the potential to reduce greenhouse gas emissions using renewable sources and thermal energy storage.

Energy model results – Scenario C

The mass and energy balance for potential Scenario **C** is presented below.

Table 6-26. The mass and energy balance for Scenario C (Heat and EE production)

Units	Heat production		EE production		EE consumption
	MWh	%	MWh	% (condensing)	MWh
Solar	16.003,66	0,93%			
HOB-West					
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	162.713,66	9,43%	204.245,73		0,00
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Source 1/2/3					
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	170.013,18	9,86%	187.429,77		0,00
Electric hot water boilers - 40 MWe (x1)	28.219,31	1,64%	0,00		-28.504,35
CHP (WtE) [Boiler + ST] (x1)	209.787,79	12,16%	43.599,33		0,00
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	75.494,19	4,38%	0,00		-21.665,03
CHP (type 3) [GT 9G.04 + HRSB + ST]	833.214,79	48,31%	3.680.890,28	54,57%	-67.632,18
Industrial sector (priority)	0,00	0,00%	0,00		0,00
Existing unit at Source 1 / CHP 1 - reconstructed	208.510,33	12,09%	252.697,09		0,00
Existing unit at Source 1 / CHP 2	20.756,52	1,20%	31.252,14		0,00
Existing unit at Source 1 / CHP 3	69,73	0,00%	176,48		0,00
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
HOB-South					
No additional units are introduced...	0,00	NA	0,00		0,00
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	NA	-		0,00
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	NA	-		0,00
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	NA	-		0,00
Not Covered	0,00	0,00%	0,00		0,00
TOTAL:	**1.724.783,14**	**100,00%**	**4.400.290,82**		**-117.801,56**

Table 6-27. The mass and energy balance for Scenario C (Fuel consumption and CO2 emission)

Units	Fuel consumption (NG)		CO_2 emission		Efficiency (CHP)	Efficiency (CHP EE)
	MWh	Sm^3 (n. gas)	t w (waste)	t CO_2	%	%
Solar						
HOB-West						
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	413.571,07	43.789.878,22	-	103.392,77	89,56	47,46
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Source 1/2/3						
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	394.083,24	41.726.460,33	-	84.333,81	90,70	47,56
Electric hot water boilers - 40 MWe (x1)	0,00	0,00	0,00	0,00	-	-
CHP (WtE) [Boiler + ST] (x1)	329.103,81	-	98.731,14	23.695,47	76,99	13,25
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	0,00	0,00	0,00	0,00	-	-
CHP (type 3) [GT 9G.04 + HRSB + ST]	6.680.381,63	707.334.525,09	-	1.429.601,67	67,57	55,10
Industrial sector (priority)	NA	NA	0,00	NA	NA	NA
Existing unit at Source 1 / CHP 1 - reconstructed	1.014.835,58	107.453.178,82	-	217.174,81	45,45	24,90
Existing unit at Source 1 / CHP 2	109.204,90	11.562.871,27	-	23.369,85	47,62	28,62
Existing unit at Source 1 / CHP 3	590,55	62.529,07	-	126,38	41,69	29,88
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
HOB-South						
No additional units are introduced...	0,00	0,00	-	0,00	-	-
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	0,00	-	0,00	-	-
Not Covered						
TOTAL:	**8.941.771**	**911.929.443**		**1.881.695**		

Thermal heat storage (TES) is used	Yes	
Overall energy stored in TES during the year	MWh	104.639,33

In this case, base heating needs are covered by WtE plant, existing gas engines, heat pumps, solar collectors, and new CHP plant while peak demand is met through currently available CHP units production. Electric boilers are operating in hours within the year when the selling price of heat surpasses that of electricity.

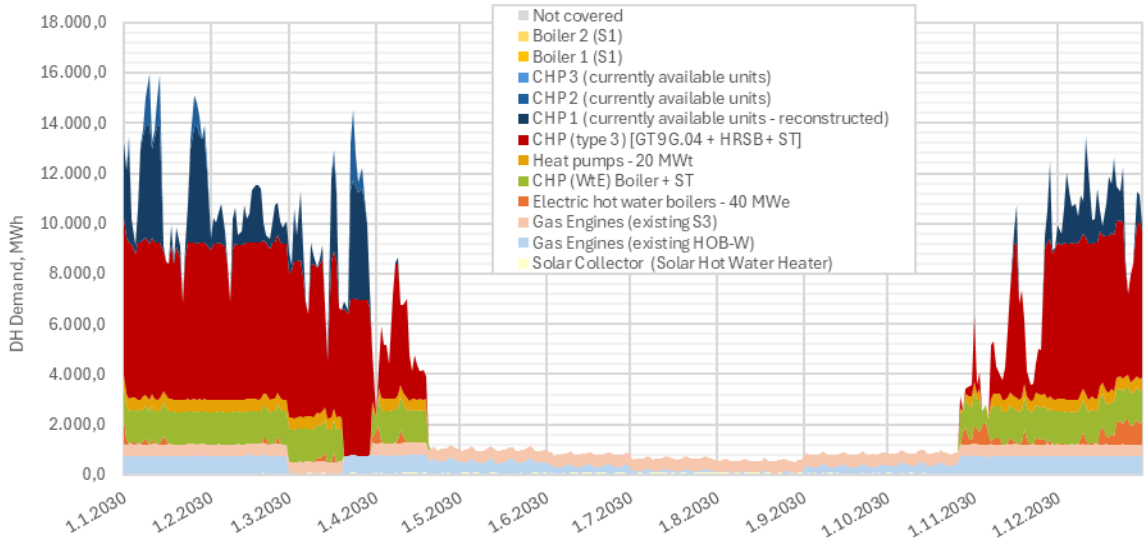


Figure 6-57. DH Demand - Scenario C

6.2.3.4 D - CHP type 4 [3 x GT LM6000 + 3 x HRB] + Heat storage (TES) + WtE + Solar collectors + Heat pumps + Electric boilers

Analysed Scenario D consists of:

- CHP type 4 unit consisting of three GT LM6000 natural gas-powered gas turbines connected to three dual-pressure Heat Recovery Boilers with overall installed capacity of 174 MW_t and 162 MW_e.
- Stationary (bubbling) fluidised bed Waste-to-energy plant with overall installed capacity of 54 MW_t and 19.75 MW_e.
- Solar collector field with overall capacity of 14 MW_t.
- One 20 MW_t two-stage R1234ze geothermal heat pumps.
- One 40 MW_t electric hot boiler with electrode heating elements.

Scenario D utilizes a CHP system consisting of three General Electric LM6000 gas turbines combined with three Heat Recovery Boilers (HRBs). This configuration is different from the previous Scenarios in the type of gas turbines and HRBs used, where the LM6000 turbine represents a flexible and highly efficient option for electricity and heat production.

The LM6000 turbines use natural gas as the primary fuel source to generate electricity, and the high-temperature exhaust gases from the turbines are directed into the Heat Recovery Boilers (HRBs) to harness their thermal energy. Each turbine has its own HRB, allowing the system to maximize the utilization of available energy from the exhaust gases. The produced steam is then directed towards the thermal energy supply network, where it is used for heating and other needs within the district heating network.

Unlike Scenarios A, B, and C, this system does not use a steam turbine; instead, thermal energy is transferred directly from the HRBs to the network. This simpler configuration allows Scenario D to have high operational flexibility, with the ability to quickly start and stop the gas turbines depending on system requirements. This characteristic makes it ideal for situations where rapid adaptation to changes in heat and electricity demand is necessary.

Scenario D also includes solar collectors, heat pumps, a Waste-to-Energy (WtE) system, and electric boilers, which increase the share of renewable energy sources in the system and reduce dependence on fossil fuels. The use of these additional components allows the system to adapt to different operating conditions, ensuring reliable energy supply and reducing greenhouse gas emissions. This configuration ensures high efficiency and reliability while reducing operating and maintenance costs.

Energy model results – Scenario D

The mass and energy balance for potential Scenario **D** is presented below.

Table 6-28. The mass and energy balance for Scenario D (Heat and EE production)

Units	Heat production		EE production		EE consumption
	MWh	%	MWh	% (condensing)	MWh
Solar	16.003,66	0,93%			
HOB-West					
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	162.713,66	9,43%	204.245,73		0,00
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Source 1/2/3					
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	170.013,18	9,86%	187.429,77		0,00
Electric hot water boilers - 40 MWe (x1)	28.219,31	1,64%	0,00		-28.504,35

CHP (WtE) [Boiler + ST] (x1)	209.787,79	12,16%	43.599,33		0,00
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	75.494,19	4,38%	0,00		-21.665,03
CHP [3 x GT-LM6000 + 3 x HRB]	599.494,34	34,76%	1.312.941,53	51,93%	-23.912,67
Industrial sector (priority)	0,00	0,00%	0,00		0,00
Existing unit at Source 1 / CHP 1 - reconstructed	394.731,53	22,89%	299.927,47		0,00
Existing unit at Source 1 / CHP 2	67.046,24	3,89%	65.760,80		0,00
Existing unit at Source 1 / CHP 3	1.279,27	0,07%	2.610,45		0,00
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
HOB-South					
No additional units are introduced...	0,00	NA	0,00		0,00
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	NA	-		0,00
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	NA	-		0,00
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	NA	-		0,00
Not Covered	0,00	0,00%	0,00		0,00
TOTAL:	**1.724.783,14**	**100,00%**	**2.116.515,07**		**-74.082,05**

Table 6-29. The mass and energy balance for Scenario D (Fuel consumption and CO2 emission)

Units	Fuel consumption (NG)		CO_2 emission		Efficiency (CHP)	Efficiency (CHP EE)
	MWh	Sm^3 (n. gas)	t w (waste)	t CO_2	%	%
Solar						
HOB-West						
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	429.439,89	45.470.106,12	-	91.900,14	85,45	47,56
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Source 1/2/3						
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	394.083,24	41.726.460,33	-	84.333,81	90,70	47,56
Electric hot water boilers - 40 MWe (x1)	0,00	0,00	0,00	0,00	-	-
CHP (WtE) [Boiler + ST] (x1)	329.103,81	-	98.731,14	23.695,47	76,99	13,25
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	0,00	0,00	0,00	0,00	-	-
CHP [3 x GT-LM6000 + 3 x HRB]	3.216.229,63	340.541.960,79	-	688.273,14	59,46	40,82
Industrial sector (priority)	NA	NA	0,00	NA	NA	NA
Existing unit at Source 1 / CHP 1 - reconstructed	1.285.431,75	136.104.538,00	-	275.082,39	54,04	23,33
Existing unit at Source 1 / CHP 2	244.911,02	25.931.755,46	-	52.410,96	54,23	26,85
Existing unit at Source 1 / CHP 3	8.858,28	937.936,03	-	1.895,67	43,91	29,47
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
HOB-South						
No additional units are introduced...	0,00	0,00	-	0,00	-	-
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	0,00	-	0,00	-	-
Not Covered						
TOTAL:	**5.908.058**	**590.712.757**		**1.217.592**		

Thermal heat storage (TES) is used	Yes	
Overall energy stored in TES during the year	MWh	104.639,33

In this case, base heating needs are covered by WtE plant, existing gas engines, heat pumps, solar collectors, and new CHP plant while peak demand is met through currently available CHP units production. Electric boilers are operating in hours within the year when the selling price of heat surpasses that of electricity.

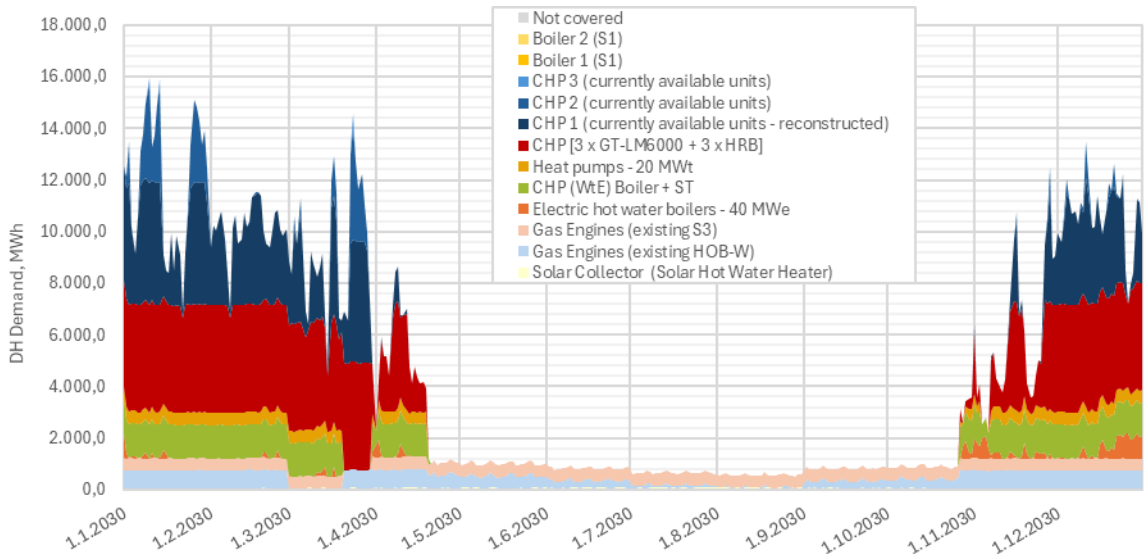


Figure 6-58. DH Demand - Scenario D

6.2.3.5 E - CHP type 5 [Gas engines Jenbacher J920] + Heat storage (TES) + WtE + Solar collectors + Heat pumps + Electric boilers

Analysed Scenario E consists of:

- CHP type 5 unit consisting of eighteen Jenbacher J920 natural gas-powered ICE connected with overall installed capacity of 185.4 MW_t and 192.6 MW_e.
- Stationary (bubbling) fluidised bed Waste-to-energy plant with overall installed capacity of 54 MW_t and 19.75 MW_e.
- Solar collector field with overall capacity of 14 MW_t.
- One 20 MW_t two-stage R1234ze geothermal heat pump.
- One 40 MW_t electric hot boiler with electrode heating elements.

Scenario E is based on a CHP system that utilizes Jenbacher J920 gas engines in combination with an integrated Thermal Energy Storage (TES) system, solar collectors, heat pumps, a Waste-to-Energy (WtE) system and electric boilers. This system utilizes up to fifteen gas engines, representing a modular and adaptable approach to electricity and heat production, ensuring a high degree of operational flexibility.

The Jenbacher J920 gas engines are powered by natural gas and are characterized by high efficiency and the ability to start up and shut down quickly. Each engine operates as an independent unit, allowing the adjustment of production capacity according to actual energy needs, thereby optimizing fuel consumption and reducing operational costs. Besides, high-efficiency heavy duty gas engines are available from a number of manufacturers on the market.

The gas engines generate electricity, while the heat produced during combustion is used to heat water, which then supplies thermal energy to the district heating network.

One of the key advantages of this scenario is its modularity, as it allows for the gradual increase of capacity by adding new gas engines based on system requirements. This approach ensures a high level of reliability, as the failure of a single engine does not significantly impact overall energy production, and maintenance can be carried out without interrupting the operation of the entire system.

Scenario E also includes solar collectors, heat pumps, a Waste-to-Energy (WtE) system, and electric boilers, which increase the share of renewable energy sources in the system and reduce dependence

on fossil fuels. The use of these additional components provides the system with high flexibility and adaptability to various operating conditions, ensuring a reliable energy supply and a reduction in greenhouse gas emissions. This configuration offers excellent efficiency and reliability while optimizing operating and maintenance costs, contributing to the sustainability of the energy system.

Energy model results – Scenario E

As it can be seen in the mass and energy balance for potential Scenario **E**, analysis is condictedu by the unit scheduling rules of the energy model. As it can be seen, renewable energy units are prioritized over gas-fired units, newly commissioned units are given priority over existing ones and combined Heat and Power (CHP) units have priority over simple boiler systems.

Table 6-30. The mass and energy balance for Scenario E (Heat and EE production)

Units	Heat production		EE production		EE consumption
	MWh	%	MWh	% (condensing)	MWh
Solar	16.003,66	0,93%			
HOB-West					
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	162.713,66	9,43%	204.245,73		0,00
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Source 1/2/3					
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	170.013,18	9,86%	187.429,77		0,00
Electric hot water boilers - 40 MWe (x1)	28.219,31	1,64%	0,00		-28.504,35
CHP (WtE) [Boiler + ST] (x1)	209.787,79	12,16%	43.599,33		0,00
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	75.494,19	4,38%	0,00		-21.665,03
Gas engines (S1) Jenbacher J920 Flextra (x18)	635.381,85	36,84%	1.594.535,40	51,93%	0,00
Industrial sector (priority)	0,00	0,00%	0,00		0,00
Existing unit at Source 1 / CHP 1 - reconstructed	368.346,33	21,36%	293.455,80		0,00
Existing unit at Source 1 / CHP 2	57.929,72	3,36%	59.035,26		0,00
Existing unit at Source 1 / CHP 3	893,47	0,05%	1.827,63		0,00
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00%	-		0,00
HOB-South					
No additional units are introduced...	0,00	NA	0,00		0,00
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	NA	-		0,00
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	NA	-		0,00
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	NA	-		0,00
Not Covered	0,00	0,00%	0,00		0,00
TOTAL:	**1.724.783,14**	**100,00%**	**2.384.128,92**		**-50.169,38**

Table 6-31. The mass and energy balance for Scenario E (Fuel consumption and CO2 emission)

Units	Fuel consumption (NG)		CO_2 emission		Efficiency (CHP)	Efficiency (CHP EE)
	MWh	Sm^3 (n. gas)	t w (waste)	t CO_2	%	%
Solar						
HOB-West						
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	429.439,89	45.470.106,12	-	91.900,14	85,45	47,56
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Source 1/2/3						
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	394.083,24	41.726.460,33	-	84.333,81	90,70	47,56
Electric hot water boilers - 40 MWe (x1)	0,00	0,00	0,00	0,00	-	-
CHP (WtE) [Boiler + ST] (x1)	329.103,81	-	98.731,14	23.695,47	76,99	13,25
SIEMENS SHP-C-600 Heat pump - 20 MWt (x1)	0,00	0,00	0,00	0,00	-	-

Gas engines (S1) Jenbacher J920 Flextra (x18)	3.447.497,09	365.029.104,04	-	737.764,38	64,68	46,25
Industrial sector (priority)	NA	NA	0,00	NA	NA	NA
Existing unit at Source 1 / CHP 1 - reconstructed	1.247.852,04	132.125.510,36	-	267.040,34	53,04	23,52
Existing unit at Source 1 / CHP 2	218.087,04	23.091.569,44	-	46.670,63	53,63	27,07
Existing unit at Source 1 / CHP 3	6.200,80	656.555,22	-	1.326,97	43,88	29,47
Boiler 1 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (Source 1) - 120 Gcal/h	0,00	0,00	-	0,00	-	-
HOB-South						
No additional units are introduced...	0,00	0,00	-	0,00	-	-
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	0,00	-	0,00	-	-
Not Covered						
TOTAL:	**6.072.264**	**608.099.306**		**1.252.732**		

Thermal heat storage (TES) is used	Yes	
Overall energy stored in TES during the year	MWh	104.639,33

In this case, base heating needs are covered by WtE plant, existing gas engines, heat pumps and solar collectors, while peak demand is met through currently available CHP units production. Electric boilers are operating in hours within the year when the selling price of heat surpasses that of electricity.

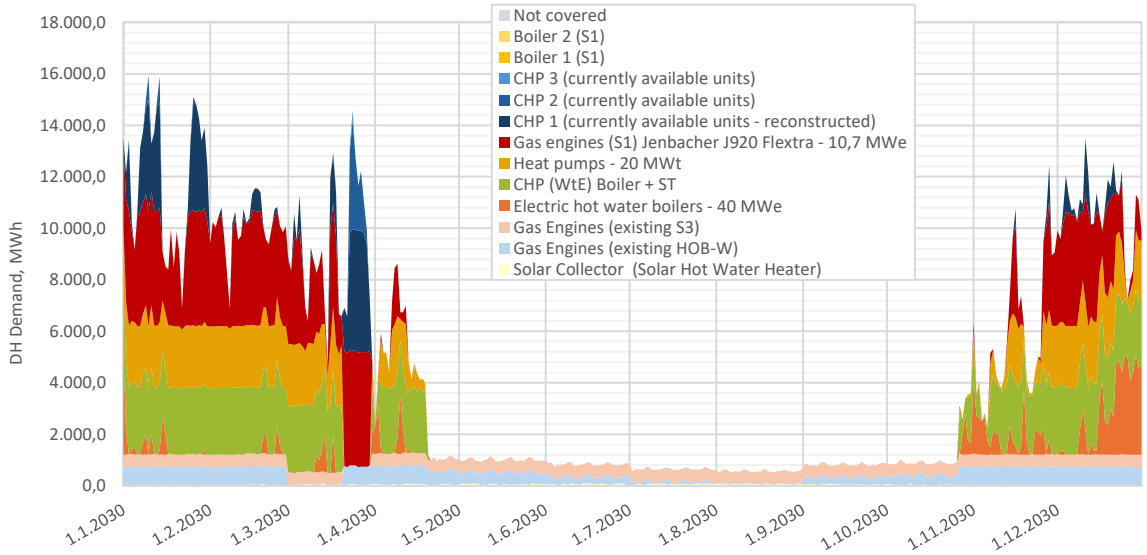


Figure 6-59. DH Demand - Scenario E

6.2.3.6 F - WtE + Solar collectors + Heat pumps + Electric boilers + Heat storage (TES)

Analysed Scenario F consists of:

- Two stationary (bubbling) fluidised bed Waste-to-energy plant with overall installed capacity of 108 MW_t and 39.5 MW_e.
- Solar collector field with overall capacity of 14 MW_t.
- Five 20 MW_t two-stage R1234ze geothermal heat pumps with overall capacity of 100 MW_t.
- Four 40 MW_t electric hot boiler with electrode heating elements with overall capacity of 160 MW_t.

The scenario based exclusively on renewable energy sources has been selected for further techno-economic analysis due to its capability to fully meet energy needs using sustainable resources which is crucial for achieving long-term environmental sustainability and reducing emissions. This system combines two Waste-to-Energy (WtE) plants, solar collectors, heat pumps, electric boilers and a

Thermal Energy Storage (TES) system to ensure a reliable energy supply with minimal environmental impact.

The Waste-to-Energy (WtE) plant allows for the efficient disposal of municipal and industrial waste while simultaneously generating thermal and electrical energy. By using waste as a resource for energy production, WtE systems reduce the amount of waste sent to landfills and greenhouse gas emissions, while also decreasing dependence on fossil fuels. This technology is particularly useful in urban environments where waste management is challenging and the need for sustainable energy sources is high.

Solar collectors in district heating systems offer significant advantages by harnessing solar energy to reduce fossil fuel consumption. They generate thermal energy for heating and any excess energy can be stored in tanks for later use, ensuring a stable supply even when sunlight is unavailable. These systems work in synergy with conventional energy sources, such as gas or biomass boilers, providing reliable and sustainable heat supply year-round, while reducing costs and greenhouse gas emissions.

Heat pumps utilize low-temperature heat sources from the environment, such as air, water, or ground, and convert them into useful energy for heating. This process allows for the efficient use of natural resources for heat transfer, reducing electricity consumption for heating and increasing the overall efficiency of the system. Combining heat pumps with renewable electricity sources further lowers the carbon footprint and enhances sustainability. Electric boilers enable the direct use of generated electricity for heating, providing flexibility and a quick response to changes in thermal energy demand. In combination with PV systems and heat pumps, electric boilers ensure the optimal use of generated electricity, contributing to the overall energy efficiency of the system.

The Thermal Energy Storage (TES) system is for balancing energy production and consumption within this system. TES allows for the storage of excess thermal energy generated from renewable sources during periods of low demand and its later use when demand is higher. This ensures a continuous and stable energy supply, increasing the overall utilization of the system and reducing the need for additional production capacities. This scenario, which integrates various renewable energy sources and storage technologies, offers a comprehensive approach to sustainable energy production and consumption. Also, it can reduce emissions, increase energy independence and optimize resource use.

Energy model results – Scenario F

The mass and energy balance for potential Scenario **F** is presented below.

Table 6-32. The mass and energy balance for Scenario F (Heat and EE production)

Units	Heat production		EE production		EE consumption
	MWh	%	MWh	% (condensing)	MWh
Solar	16.003,66	0,93%			
HOB-West					
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	162.713,66	9,43%	204.245,73		0,00
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00%	-		0,00
Source 1/2/3					
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	170.013,18	9,86%	187.429,77		0,00
Electric hot water boilers - 40 MWe (x4)	100.534,14	5,83%	0,00		-101.549,64
CHP (WtE) [Boiler + ST] (x2)	395.497,41	22,93%	82.405,58		0,00
SIEMENS SHP-C-600 Heat pump - 20 MWt (x5)	305.499,96	17,71%	0,00		-88.472,08
-	0,00	0,00%	0,00	0,00%	0,00
Industrial sector (priority)	0,00	0,00%	0,00		0,00

Existing unit at Source 1 / CHP 1 - reconstructed	444.144,84	25,75%	295.592,95		0,00
Existing unit at Source 1 / CHP 2	113.881,62	6,60%	101.039,61		0,00
Existing unit at Source 1 / CHP 3	13.603,11	0,79%	15.479,14		0,00
Boiler 1 (Source 1) - 120 Gcal/h	2.822,83	0,16%	-		0,00
Boiler 2 (Source 1) - 120 Gcal/h	68,74	0,00%	-		0,00
HOB-South					
No additional units are introduced...	0,00	NA	0,00		0,00
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	NA	-		0,00
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	NA	-		0,00
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	NA	-		0,00
Not Covered	0,00	0,00%	0,00		0,00
TOTAL:	**1.724.783,14**	**100,00%**	**886.192,77**		**-190.021,72**

Table 6-33. The mass and energy balance for Scenario F (Fuel consumption and CO2 emission)

Units	Fuel consumption (NG)		CO_2 emission		Efficiency (CHP)	Efficiency (CHP EE)
	MWh	Sm^3 (n. gas)	t w (waste)	t CO_2	%	%
Solar						
HOB-West						
Gas Engine (existing HOB-W) - 33 MWe / 25,8 Gcal/h	429.439,89	45.470.106,12	-	91.900,14	85,45	47,56
Boiler 1 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-W) - 100 Gcal/h	0,00	0,00	-	0,00	-	-
Source 1/2/3						
Gas Engines (existing S3) - 22 MWe / 17,2 Gcal/h	394.083,24	41.726.460,33	-	84.333,81	90,70	47,56
Electric hot water boilers - 40 MWe (x4)	0,00	0,00	0,00	0,00	-	-
CHP (WtE) [Boiler + ST] (x2)	621.418,58	-	186.425,58	44.742,14	76,91	13,26
SIEMENS SHP-C-600 Heat pump - 20 MWt (x5)	0,00	0,00	0,00	0,00	-	-
-	0,00	0,00	-	0,00	-	-
Industrial sector (priority)	NA	NA	0,00	NA	NA	NA
Existing unit at Source 1 / CHP 1 - reconstructed	1.296.985,30	137.327.855,21	-	277.554,85	57,04	22,79
Existing unit at Source 1 / CHP 2	386.341,37	40.906.732,90	-	82.677,05	55,63	26,15
Existing unit at Source 1 / CHP 3	55.511,71	5.877.710,34	-	11.879,51	52,39	27,88
Boiler 1 (Source 1) - 120 Gcal/h	2.822,83	298.888,32	-	604,09	-	-
Boiler 2 (Source 1) - 120 Gcal/h	68,74	7.277,89	-	14,71	-	-
HOB-South						
No additional units are introduced...	0,00	0,00	-	0,00	-	-
Boiler 1 (HOB-S) - 26 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 2 (HOB-S) - 42 Gcal/h	0,00	0,00	-	0,00	-	-
Boiler 3 (HOB-S) - 70 Gcal/h	0,00	0,00	-	0,00	-	-
Not Covered						
TOTAL:	**3.186.672**	**271.615.031**		**593.706**		

Thermal heat storage (TES) is used	Yes	
Overall energy stored in TES during the year	MWh	104.639,33

In this case, base heating needs are covered by WtE plant, existing gas engines, heat pumps and solar collectors, while peak demand is met through currently available CHP units production and also boilers. Boilers are activated when heat demand reaches low as 10,000 MWh/h. Electric boilers are operating in hours within the year when the selling price of heat surpasses that of electricity.

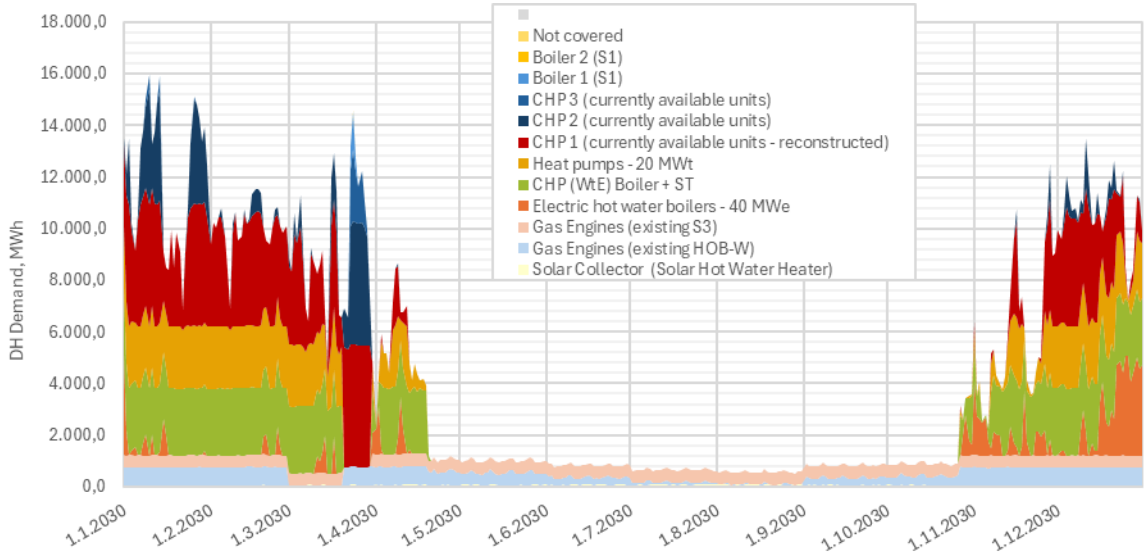


Figure 6-60. DH Demand - Scenario F

6.3 Reserve Fuel Strategy for CHP Operation

Moldova, and particularly its capital Chisinau, faces significant challenges in ensuring energy security due to its high dependence on imported natural gas. The existing district heating system (DHS) in Chisinau supplies a large portion of the city's heating demand, and the proposed Combined Heat and Power (CHP) plants are designed to enhance efficiency and reliability. Given the region's geopolitical vulnerabilities, reserve fuel storage is crucial for maintaining CHP operations in the event of gas supply disruptions.

The CHP plant configurations analyzed in this study, CHP Type 2 and CHP Type 5, incorporate gas turbines and gas engines respectively, each with different fuel flexibility characteristics. The ability to operate on alternative fuels provides redundancy and enhances system resilience. This section evaluates the best alternative fuel options, their technical characteristics, storage requirements, and the financial implications of implementing a reserve fuel system.

6.3.1 Reserve Fuel for Gas Turbines

For heavy-duty gas turbines (CHP type 1, CHP type 2 and CHP type 3), the most viable reserve fuel is Diesel No. 2 (Distillate Fuel Oil No. 2), which offers high energy density, rapid start-up capability, and widespread availability. Aeroderivative gas turbines (CHP type 4) can use either D-2 or Jet A (kerosene) as reserve fuel. Gas turbines can be adapted for dual-fuel operation, allowing seamless transition from natural gas to diesel in case of gas supply interruptions.

Advantages of D-2 as Reserve Fuel are presented below:

- Fuel Availability: Diesel is readily available in Moldova and can be stored in on-site tanks.
- Storage Stability: Unlike LNG or hydrogen, diesel is easy to store long-term without significant evaporation or loss.

- Fast Switching: Gas turbines can transition to diesel within minutes, ensuring uninterrupted power and heat supply.
- No Cryogenic Storage Required: Unlike LNG, diesel does not require high-pressure or cryogenic storage infrastructure.
- Cold Weather Reliability: Diesel remains operable at low temperatures with proper additives.

6.3.2 Reserve Fuel for Gas Engines

Diesel is not a suitable fuel for CHP Type 5 because gas engines require gaseous fuels with high knock resistance, such as natural gas, biogas, or LPG. Unlike gas turbines, which can use liquid fuels with minor modifications, gas engines rely on spark ignition and a homogeneous air-fuel mixture, which diesel cannot provide. Unlike gas turbines, gas engines have greater fuel flexibility, making them compatible with Liquefied Petroleum Gas (LPG) and Biogas as primary backup fuels. LPG is the preferred choice due to its ease of storage and rapid switching capability, while biogas can be attractive option for long-term sustainability.

Advantages of LPG as Reserve Fuel are as follow:

- Ease of Storage: LPG can be stored in pressurized tanks without requiring cryogenic facilities.
- Dual-Fuel Operation: Gas engines can automatically switch from natural gas to LPG without significant modifications.
- Widespread Availability: LPG is already used in Moldova and can be sourced reliably.

6.3.3 Comparison of Reserve Fuel Strategies

The following table presents key properties of Diesel No. 2 and LPG, providing a basis for their comparison in terms of efficiency and environmental impact.

Table 6-34. Key properties of Reserve Fuels

Property	Unit	Diesel No. 2	LPG
Lower heating value (LHV)	MJ/kg	42,5	46,1
	MJ/l	35,8	25,5
Higher heating value (HHV)	MJ/kg	45,5	50,0
	MJ/L	38,6	27,1
Density (at 15 °C)	kg/m^3	840	500
Viscosity (at 40 °C)	mm^2/s (cSt)	2 – 4	N/A
Sulfur content	mg/kg or ppm	≤ 15	Negligible
Cetane number	-	40 – 55	N/A
Octane number	-	N/A	110
Vapur pressure	kPa	N/A	520 (at 37,8 °C)
Flash point temperature	°C	≥ 55 °C	-104
Autoignition temperature	°C	250 °C	470
Stoichiometric air-fuel ratio	-	14,5	15,7
CO_2 emission factor	kg CO_2/kg	2,68	2,99
Hydrogen content	%	≈ 13,5	≈ 17,5
Carbon content	%	≈ 86,0	≈ 82,5
Oxygen content	%	≈ 0	≈ 0
Ash content	%	< 0,01	Negligible

A comparative assessment of Diesel No. 2 (for gas turbines) and LPG/Biogas (for gas engines) is presented below:

Criteria	CHP Type 2 – Gas Turbines (SGT800)	CHP Type 5 – Gas engines (Jenbacher J920 FleXtra)
Primary backup fuel	Diesel no.2	LPG
Secondary backup fuel	LNG (if infrastructure exsist)	Biogas (locally sourced)
Switching time	Fast (< 10 min)	Instant (<1 min)
Storage infrastructure	Above ground diesel tanks	Pressurized LPG tanks, biogas digesters
Operational impact	Requires fuel forwarding system, filtration	LPG requires vaporization, biogas requires upgrading
Long–term sustainability	Not a sustainable fuel	Biogas is a renewable energy source

The following table compares different CHP types based on their reserve fuel type, heating value (MJ/kg), full-load consumption (kg/h and m³/h), and fuel input at full load (MW).

Table 6-35. Comparison based on reserve fuel

CHP Type		CHP Type 1 (2xSGT800)	CHP Type 2 (3xSGT800)	CHP Type 3 (1x GT 9F.04)	CHP Type 4 (3xLM6000)	CHP Type 5 (18xJ920 FleXtra)
Best reserve fuel		Diesel no.2	Diesel no.2	Diesel no.2	Diesel no.2	LPG
Heating value of reserve fuel	MJ/kg	42,5	42,5	42,5	42,5	46,1
Consumption at full load	kg/h	26.951,55	41.391,78	64.596,79	32.910,52	32.518,31
	m^3/h	32,09	49,27	76,90	39,18	65,04
Fuel input at full load	MW	318,178	488,653	762,601	388,527	416,415

The reserve fuel storage system for CHP Type 2 consists of two vertical cylindrical storage tanks, each with a capacity of 8,500 m³, providing a total of 17,000 m³ of Diesel No. 2 to sustain full-load operation for two weeks. These tanks are double-walled steel structures, designed to ensure durability and environmental safety, with integrated leak detection systems to monitor and prevent any potential spills. The tanks are equipped with internal insulation and anti-corrosion coatings, ensuring long-term reliability while maintaining fuel quality.

A fuel transfer system is in place, comprising high-capacity pumps, pipelines, and filtration units that ensure smooth and efficient fuel delivery to the gas turbines. The system includes pressure-regulated supply lines to maintain a steady fuel flow and prevent cavitation or pressure drops that could impact turbine performance. To address temperature variations, a heating system is incorporated, preventing the diesel from thickening in cold weather and ensuring optimal fuel viscosity for combustion efficiency.

To minimize evaporative losses and meet environmental regulations, a vapor recovery system is installed, capturing and recycling fuel vapours that would otherwise escape into the atmosphere. Fire safety is a critical aspect of the design, with the storage system featuring automatic fire suppression systems, foam sprinklers, and emergency shut-off valves strategically placed to provide rapid containment in case of an incident.

Continuous monitoring and control are ensured through a digital fuel management system, which includes real-time level sensors, temperature monitoring devices, and automated fuel quality assessment tools. These elements allow operators to track consumption patterns, detect anomalies, and optimize refueling schedules, ensuring operational reliability and efficiency. The entire system is designed to balance security, cost-efficiency, and regulatory compliance, providing a robust and sustainable fuel reserve for CHP Type 2.

The decision to implement a two-week storage capacity for Diesel No. 2 at CHP Type 2 is based on a combination of operational security, logistical feasibility, and cost optimization. Ensuring an uninterrupted fuel supply is critical for maintaining stable power generation in case of disruptions in natural gas availability. A two-week reserve strikes a balance between long-term energy security and economic efficiency, avoiding excessive investments in oversized storage while guaranteeing sufficient autonomy for the plant.

Table 6-36. Fuel storage specifications

Storage duration	Total storage capacity (m^3)	Number of tanks	Tank capacity (m^3)	Tank diameter (m)	Tank height (m)
One-Week Storage	8,500	2	4,250	14,1	28,6
Two-Week storage	17,000	2	8,500	18,2	34,3
Monthly Storage	34,000	2	17,000	23,0	43,0

Table 6-37. Estimated CAPEX for diesel fuel storage

Storage duration	Total storage capacity (m^3)	Number of tanks	Esimeted CAPEX, million EUR
One-Week Storage	8,500	2	3,0 – 3,5
Two-Week storage	17,000	2	5,0 – 6,0
Monthly Storage	34,000	2	9,5 – 11,0

Maintaining long-term security of supply requires a storage volume that accounts for potential delays in diesel transportation while ensuring operational flexibility. A smaller reserve, such as a one-week supply, would expose the facility to risks of short-term disruptions in rail logistics or refinery output fluctuations, while a larger reserve beyond two weeks would result in unnecessary capital expenditure and increased operational costs related to storage maintenance and fuel turnover. Diesel has a limited shelf life of approximately one year, requiring regular fuel cycling to prevent degradation and maintain quality. A two-week storage configuration ensures that stored diesel is regularly consumed and replenished, preventing long-term stagnation that could lead to fuel contamination, water accumulation, or deterioration of combustion properties.

To ensure reliable fuel supply, diesel will be delivered by rail transport from the Petrobrazi Refinery in Romania, which is located approximately 350 kilometers from Chișinău. Given the facility's weekly fuel demand, the most efficient transport solution involves scheduling regular train deliveries every two to three days. Each standard freight train consists of approximately 35 oil wagons, each with a capacity of around 60,000 liters, ensuring that fuel reserves are maintained at optimal levels without excessive storage buildup. This approach guarantees a stable and predictable supply chain while reducing the need for costly emergency fuel procurement.

The storage infrastructure consists of two equally sized cylindrical tanks, each capable of holding 7,500 cubic meters of diesel, providing redundancy and flexibility in fuel management. This dual-tank configuration allows for continuous operation during maintenance or cleaning procedures, ensuring that at least one tank remains available at all times. The ability to alternate between tanks also reduces the risk of contamination and enables systematic fuel turnover, keeping the reserve within the necessary quality standards.

By implementing a two-week storage system, CHP Type 2 achieves energy security while optimizing both capital investment and operational costs. The plant remains fully protected against short-term supply disruptions, while the chosen capacity ensures efficient turnover of stored fuel, minimizing risks associated with fuel degradation and excessive inventory. The logistical strategy is aligned with the availability of regional fuel supply infrastructure, ensuring stable, cost-effective, and sustainable operation.

To ensure fuel security while optimizing capital (CAPEX) and operational (OPEX) costs, a two-week on-site reserve of Diesel No. 2 (D-2) stored in two tanks is proposed for CHP Type 2 (3 x SGT800

gas turbines). This balance between storage capacity, supply chain logistics, and cost efficiency provides long-term reliability without unnecessary investment in excessive storage infrastructure.

Reasoning for Two-Week Storage

- Security of Supply – A two-week reserve ensures continuous operation in case of temporary fuel supply disruptions, political instability, or logistical delays.
- Cost Optimization – Building two storage tanks instead of an oversized single-tank system reduces initial CAPEX while maintaining sufficient redundancy for risk mitigation.
- OPEX Efficiency – Diesel No. 2 has a limited shelf life (~12 months) and must be consumed within a reasonable period to avoid degradation and maintenance issues related to fuel quality. A two-week reserve ensures that stock turnover aligns with operational needs, preventing excess fuel from aging.

Storage Infrastructure and Logistics

- Tank Configuration – Two equal-sized storage tanks allow for flexible refilling cycles while ensuring redundancy in case of maintenance or contamination issues.
- Train Deliveries – With a weekly fuel requirement of approximately 104 oil wagons, a freight train with 35 wagons would need to arrive every 2–3 days. The proximity of the Petrobrazi Refinery in Romania (~350 km from Chișinău) ensures a reliable and consistent fuel supply with minimal transportation delays.
- Long-Term Security – This approach allows stable operation even in cases where supply chains experience short-term disruptions while avoiding unnecessary costs from excessive storage construction and unused diesel stock.

By implementing a two-week reserve in two tanks, CHP Type 2 ensures energy security while maintaining economic efficiency, aligning with both technical and financial best practices for long-term sustainable operation.

6.4 Integration of CHP units in power system of Moldova

6.4.1 Technical Capabilities to Provide Regulatory Services to the Power System

The new Combined Heat and Power (CHP) facility at Termoelectrica S.A. is designed to provide high-efficiency cogeneration while supporting the stability and reliability of the Moldovan power system. Given the increasing integration of intermittent renewable energy sources, the ability of the CHP plant to participate in frequency and power regulation services is a critical factor in ensuring grid stability.

Modern CHP systems are required to synchronize with the grid to provide regulatory services effectively. All CHP configurations must achieve stable synchronization before participating in primary, secondary, or tertiary regulation. The ability to ramp up or down within defined timeframes is essential for compliance with grid code requirements and market participation in ancillary services.

The regulation energy market ensures real-time balance between electricity generation and consumption by compensating for short-term fluctuations beyond the planned dispatch schedule. This regulation is structured hierarchically into three main levels:

- Primary Regulation: Provides the fastest response (within 30 seconds) and is automatically activated based on local frequency measurements.
- Secondary Regulation: Activated within 5 minutes, balancing the system following primary regulation through an automatic control system.
- Tertiary Regulation: Activated within 7 to 15 minutes based on dispatcher commands, used when primary and secondary reserves are insufficient or for system optimization.

In this case, the differences between the analysed CHP Type 1–5 variants primarily relate to their operational flexibility and ability to participate in primary, secondary, and tertiary regulation. All variants, except one, are based on gas turbines, while CHP Type 5 relies on gas engines, providing a significant advantage in terms of response speed and load adjustment.

CHP Type 1 and CHP Type 2 use Siemens SGT-800 gas turbines in a combined cycle configuration, integrating heat recovery steam boilers (HRSBs) and a steam turbine. Each gas turbine has a rated electrical output of 62 MW, with a minimum load of approximately 44 MW per unit, ensuring stable operation. These configurations offer flexibility by allowing one gas turbine to remain operational while the second is in standby or hot start mode, ensuring a rapid response when additional capacity is needed. With one HRSB already running, steam production begins immediately upon starting the second turbine. A dump condenser enables the steam cycle to bypass the steam turbine until steam parameters reach optimal levels. This setup enhances flexibility by providing immediate heat utilization while minimizing start-up delays. One gas turbine has a ramp rate of 10 MW/min per unit, providing a total ramp-up capability of 20(30) MW/min for the plant, ensuring stable secondary and tertiary regulation.

CHP Type 3 features a single large GE 9F.04 heavy-duty gas turbine with a rated electrical output of approximately 288 MW and a minimum load of 202 MW. While this turbine achieves high efficiency, its larger size and inertia slow its response to load variations, making it less suitable for primary regulation. Secondary regulation is constrained due to the turbine's slower ramp rate of 23 MW/min. Tertiary regulation remains its best application, as it can provide significant power support when needed. However, its startup time is considerably longer, requiring approximately 23–30 minutes from a hot start and around 90 minutes from a cold start, reducing its ability to react swiftly to grid fluctuations.

CHP Type 4 utilizes LM6000 aeroderivative gas turbines, significantly improving response time compared to heavy-duty turbines. Each turbine has a rated electrical output of approximately 50 MW, with a minimum load that is effectively zero (house load). The system benefits from a high ramp rate of 30 MW/min per unit, yielding a total plant ramp-up capability of 90 MW/min for a 3x1 combined cycle configuration. These turbines can reach full load in approximately five minutes from a hot start and ten minutes from a cold start. Their operational characteristics make them well-suited for secondary and tertiary regulation, offering better load-following capability and adaptability to grid demand fluctuations compared to heavy-duty gas turbines.

CHP Type 5 consists of multiple Jenbacher J920 FleXtra gas engines, each with a rated electrical output of approximately 9.5 MW, operating in a highly modular system. The minimum load is effectively zero (house load), allowing for extreme flexibility in operation. With a total ramp rate of 86.4 MW per minute, this configuration is the most adaptable, capable of providing primary, secondary, and tertiary regulation efficiently. The system can reach full capacity within three minutes from a hot start and approximately ten minutes from a cold start. The modular nature of the gas engines enables precise load control and real-time balancing of power output, making it the most responsive CHP configuration among the analyzed options.

The ability of each CHP type to provide tertiary and secondary regulation depends on its operational state. Gas turbines must operate at a minimum of 70% load to comply with emissions regulations, ensuring they meet Minimum Emissions Compliance Load (MECL) requirements. Although gas turbines can technically operate at loads as low as 25%, running below MECL threshold for extended

periods is not recommended due to environmental reasons. However, for short durations, gas turbines can accommodate higher load fluctuations beyond standard regulation levels, providing additional flexibility in critical grid stabilization scenarios. The ability of each CHP type to provide tertiary and secondary regulation depends on its operational state:

- From hot start: CHP Types 1, 2, 4, and 5 can offer tertiary regulation as they can achieve full operational conditions quickly.
- If units are already operating (all GTs at ≥70% load): All CHP types (1, 2, 3, 4, and 5) can provide both tertiary and secondary regulation.
- From cold start: Only CHP Types 4 and 5 can offer tertiary regulation due to their fast cold start capabilities (~10 minutes).
- Updated Regulatory Capabilities Table

Table 6-38. Technical capability to provide regulatory services

Technical Parameter	CHP type 1	CHP type 2	CHP type 3	CHP type 4	CHP type 5
Minimum Load (MW)	44	44	202	~0 (House Load)	~0 (House Load)
Ramp Rate (MW/min) – one GT/engine	10	10	23	30	5
Ramp Rate (MW/min) – CHP	20	30	23	90	90
Primary Regulation Capability	Limited	Limited	Minimal	Moderate	High
Secondary Regulation Capability	Moderate	Moderate	Constrained	High	High
Tertiary Regulation Capability	High	High	Constrained	High	High
Startup Time (Hot Start)	~10 min	~10 min	~23-30 min	~5 min	~3 min
Startup Time (Cold Start)	~60 min	~60 min	~90 min	~10 min	~10 min

The technical capabilities of each CHP configuration define their suitability for providing regulatory services. CHP Type 5, based on gas engines, is the most adaptable option, excelling in all three regulation categories. CHP Type 4, with aeroderivative gas turbines, offers strong secondary and tertiary regulation capabilities. CHP Types 1, 2, and 3 are better suited for tertiary regulation due to their slower response times but still contribute to system stability.

6.4.2 Energy Production and Covering Power Needs

To integrate the generating units into Moldova's power system, the hourly electricity consumption profile from 2023 was used. **Part of the electricity is generated, depending on the selected option, using one of the following generating units:**

- CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]
- CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]
- CHP (type 3) [GT 9G.04 + HRSB + ST]
- CHP [3 x GT-LM6000 + 3 x HRB]
- 18 x Gas engines (S1) Jenbacher J920 Flextra

For these units, a scheduled maintenance period of 20 days in August has been assumed, during which all necessary maintenance activities will be carried out to ensure reliability and optimal efficiency in the upcoming operational cycle.

Additional electricity generation is provided by the following units:

- CHP Waste-to-Energy with a total capacity of 20 MW. The plant operates year-round, with maintenance conducted over two summer months
- Existing gas engines with a total capacity of 50 MW, operating during the heating season.
- Hydropower plants with a total capacity of 18 MW, utilized throughout the year.
- Solar power plants with a total capacity of 60 MW. The electricity output depends on various factors and reaches its peak during the summer months.
- Wind power plants with a total capacity of 115 MW. The electricity output depends on wind patterns.
- Biogas plants with a total capacity of 15 MW. They operate year-round, with maintenance carried out over one summer month.

The remaining required electricity is supplied through imports to meet demand and maintain the stability of the power system. During periods when electricity generation exceeds current needs, the surplus is exported (CHP type 3 + other units), optimizing the utilization of generation capacity and enabling efficient integration into the broader energy system.

The following diagrams illustrate the integration of the specified generating units into the power system, depending on the selected option. The diagrams depict the distribution of electricity generation among the individual units, their contribution to the overall supply, and the way they adapt to varying consumption conditions and energy source availability.

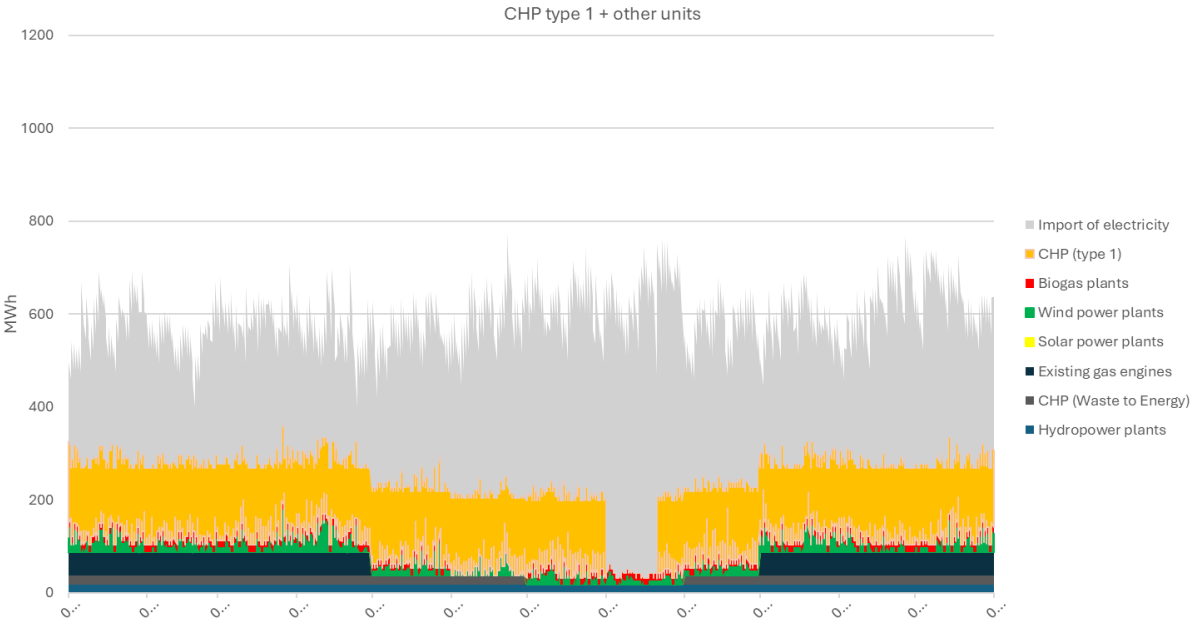


Figure 6-61. Integration of CHP type 1 in Moldova electricity market

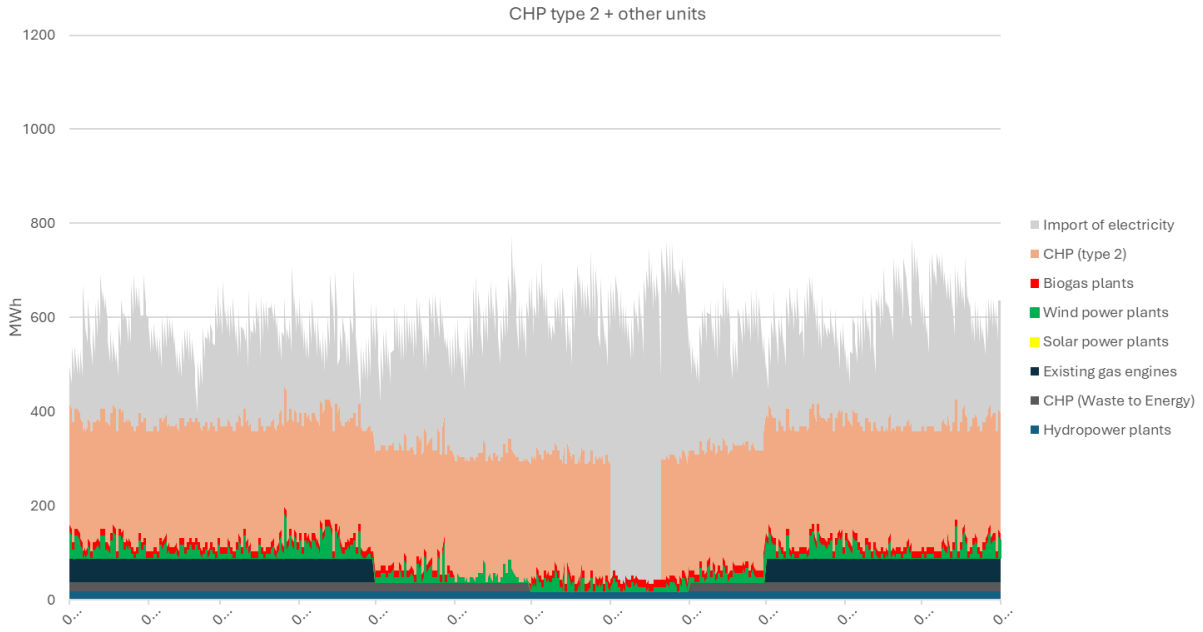


Figure 6-62. Integration of CHP type 2 in Moldova electricity market

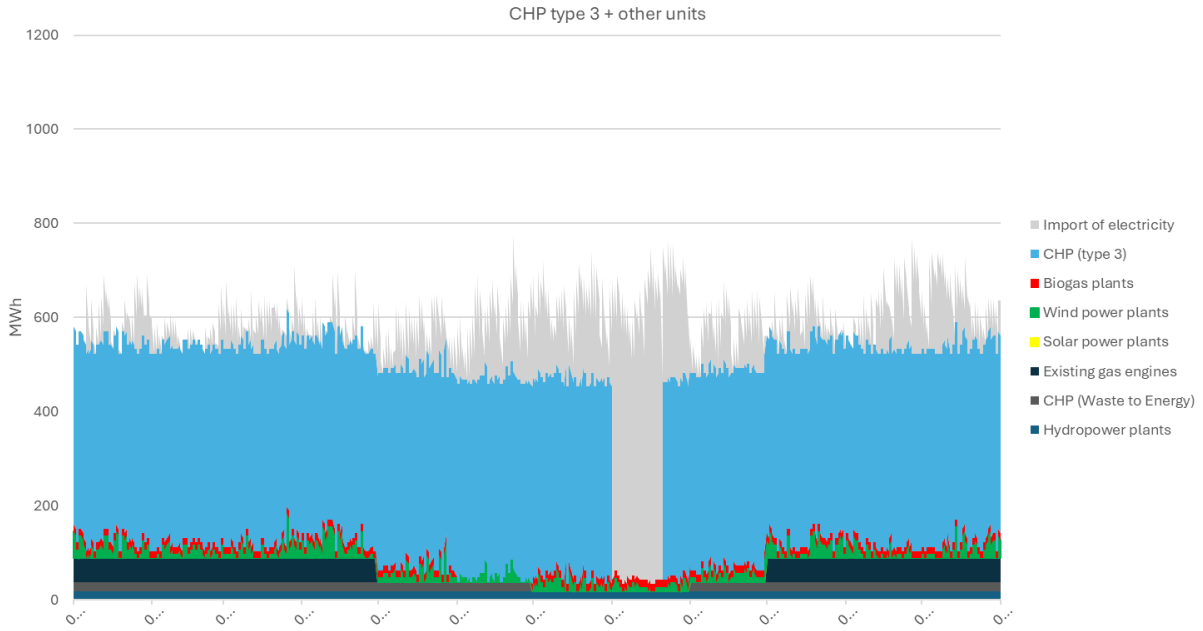


Figure 6-63. Integration of CHP type 3 in Moldova electricity market

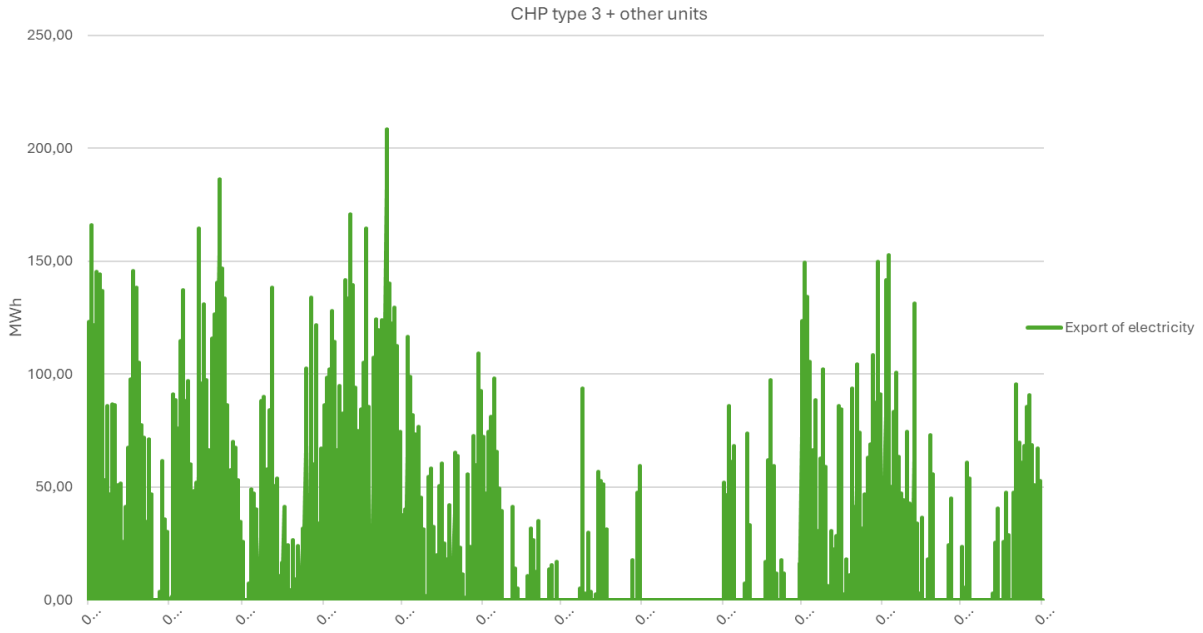


Figure 6-64. Export of electricity form Moldova to regional market by CHP type 3

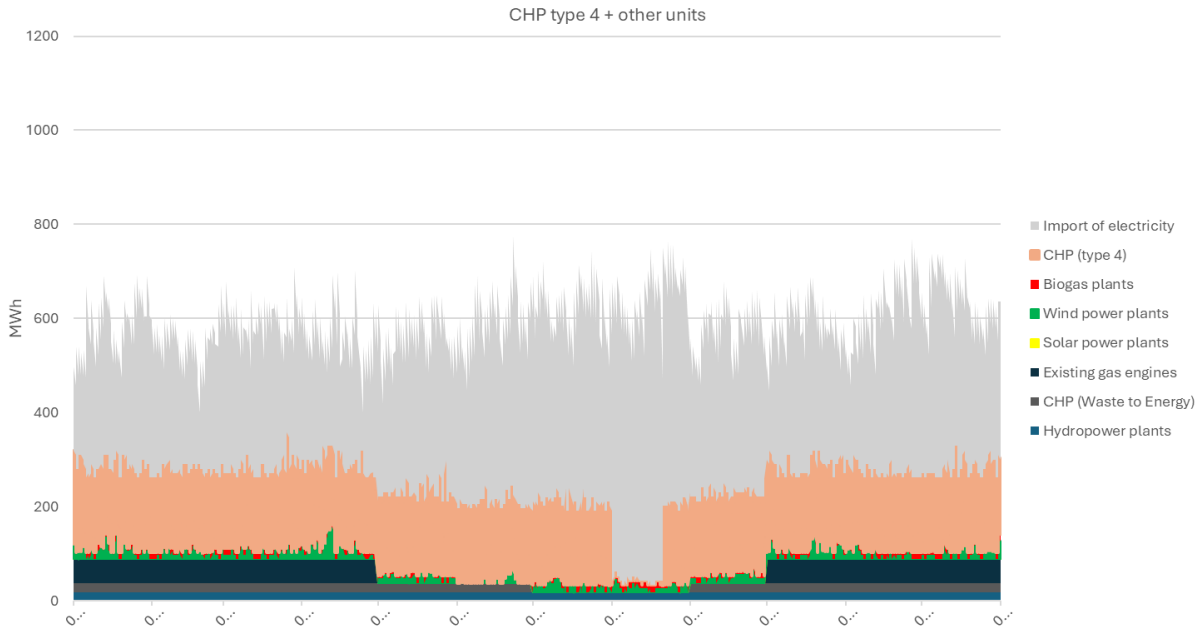


Figure 6-65. Integration of CHP type 4 in Moldova electricity market

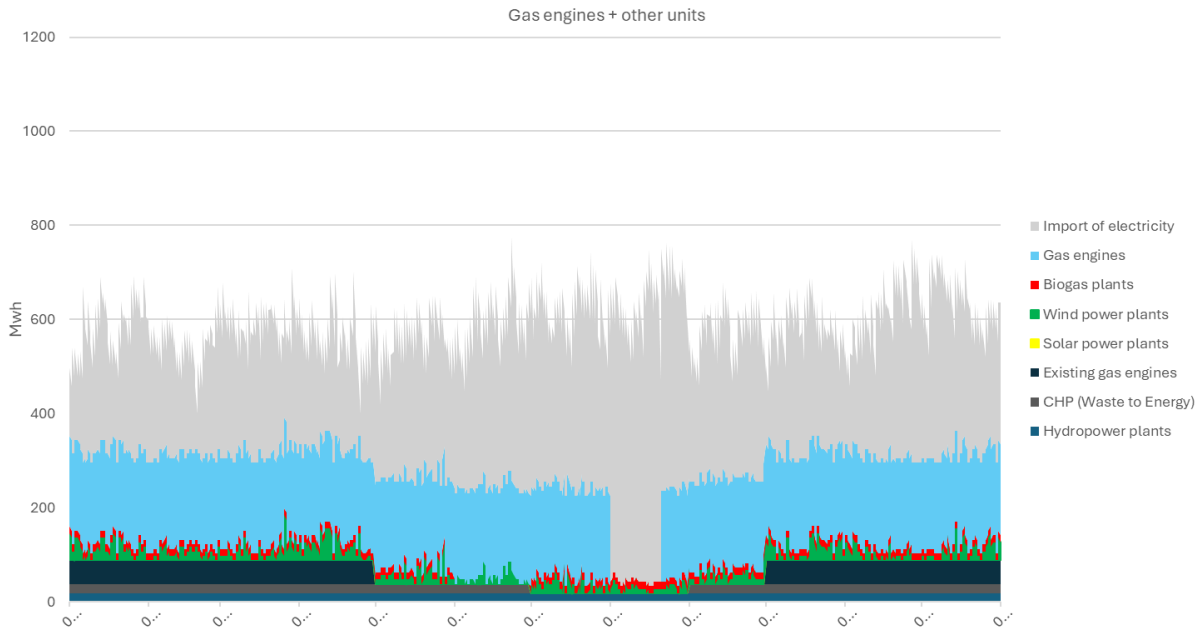


Figure 6-66. Integration of CHP type 5 in Moldova electricity market

The following table presents the final analysis results, including the share of the new generating unit in total electricity generation and the percentage of electricity that must be imported to meet overall consumption.

Table 6-39. Final analysis results

New Unit	Share in total electricity generation	Share of imported electricity
CHP type 1	23.79%	60.68%
CHP type 2	36.66%	47.82%
CHP type 3	60.37%	25.76%
CHP type 4	22.78%	61.69%
Gas engines	27.67%	56.80%

6.5 Scenario analysis in the context of adopted national targets regarding climate change mitigation and renewable energy share

As stated in the National Energy and Climate Plan (NECP), Moldova has committed to an ambitious national objective for climate change mitigation. The primary goal is to reduce greenhouse gas (GHG) emissions by 70% below 1990 levels by 2030. This target translates to a cap of 13.47 Mt CO2eq, excluding emissions from the Land Use, Land Use Change, and Forestry (LULUCF) sector. Key sub-objectives to achieve this reduction are outlined below:

1. **Industrial Processes and Product Use (IPPU) Sector**:
   Moldova aims to reduce GHG emissions from the IPPU sector by 27% relative to the reference year by 2030, under the unconditional scenario. Under a conditional scenario, the reduction target increases to 31%.

2. **Agriculture Sector**:
   GHG emissions from agriculture are targeted for a 44% reduction by 2030 under the unconditional scenario, with a more aggressive target of 47% under the conditional scenario. The strategy supports the adoption of low-carbon development approaches within the agricultural sector.

3. **Land Use, Land Use Change, and Forestry (LULUCF)**:
   Carbon sequestration is expected to increase by 10% by 2030 under the unconditional scenario, with a significant increase of 391% under the conditional scenario.

4. **Waste Sector (Including Wastewater)**:
   Emissions from the waste sector are targeted for a reduction of 14% by 2030 under the unconditional scenario, and 18% under the conditional scenario. Efforts in this sector include promoting low-carbon innovations and climate-friendly technologies.

In addition to these GHG mitigation targets, Moldova has committed to increasing its share of renewable energy in its gross final energy consumption. The 2030 Framework target, established by the Energy Community Ministerial Council (EnC-MC) in 2012, set a goal of achieving 17% renewable energy share by 2020. In the National Energy Strategy 2030 this target is voluntarily increased to 20%.

According to the Ministerial Council Decision No. 2022/02/MC-EnC, Moldova's updated renewable energy target is to reach 27% by 2030. Under the NECP scenario, with planned measures, the country aims to further elevate this target to 31.4% by 2030.

Moldova exceeded its overall 2020 renewable energy target, achieving a 25.06% share of renewable energy, surpassing the initial target of 17%. However, this success was predominantly in the heating and cooling sector where Moldova already overreached set target, while contributions from

renewable energy in electricity generation and transport remain notably low, highlighting areas for further development.

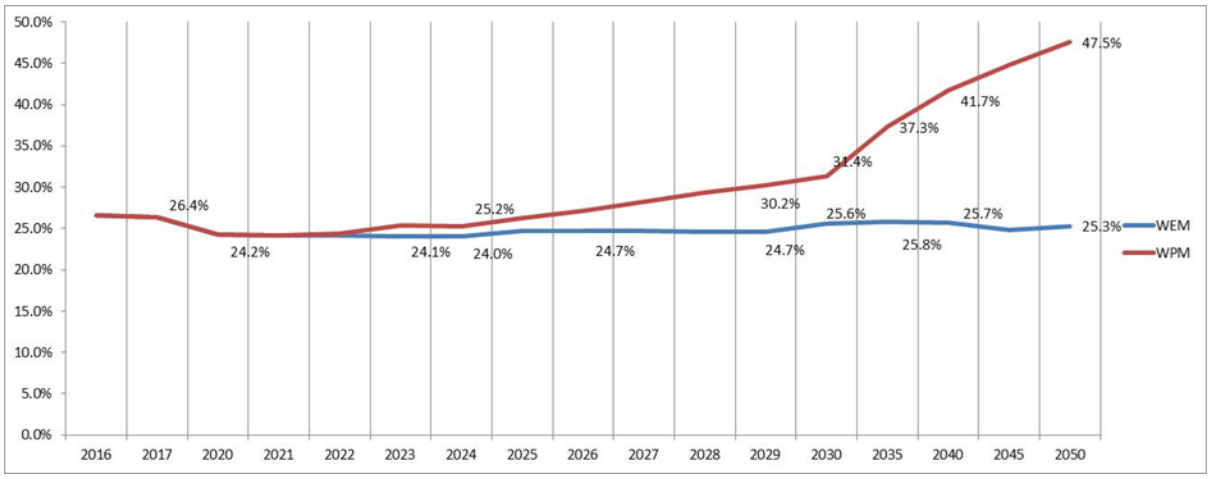


Figure 6-67. Trajectories of RES in final gross consumption of Moldova in the period 2016 – 2050 (NECP)

6.5.1 Proposed CHP scenarios in the context of meeting national targets

Considering status of existing power generation units, new CHP unit would completely replace existing facilities at CHP Source 2 plant, which is planned to be closed in near future, as well as CHP Source 1 plant, which have exceeded its original operation lifetime, and its power generating units are maintained and overhauled to extend their operation lifetime until new energy generation block is built.

Taking into consideration CHP units in both plants are low efficiency Steam Power Generation based CHP units which are based on combination of steam generator (boiler) and steam turbine, introduction of new plants would increase energy production efficiency and decrease CO_2 emissions, especially when looking at electricity generation. Efficiency for CHP units in CHP Source 1 is reported to reach 35% in condensing mode. Also, when considering all production units in the CHP Source 1, average overall efficiency of energy production between 2012 and 2018 was only 74% (in optimal cogeneration mode it can reach circa 80-82%).

Considering these efficiency values, all of the proposed CHP options showed greater overall efficiency results in the modelled scenarios which lead to decreasing fuel consumption and/or increased energy production resulting in lower CO2 emissions. All proposed scenarios integrate Thermal Energy Storage (TES), as well as WtE CHP, solar collectors and heat pumps to ensure a reliable energy supply and enable minimisation of environmental impact.

Three scenarios (A, B and C) include Combined Cycle Power Generation CHP system consisting of gas turbines, heat recovery steam boilers (HRSB), and back-pressure steam turbines, which greatly increases electrical efficiency of the unit. On the other hand, inclusion of heat storage in all scenarios enables optimisation of operation of these plants, especially when working in parallel with some other energy sources and variable heat demand. Also, the use of natural gas as a fuel and advanced heat recovery technology via the HRSB results in reduced CO_2 emissions and other harmful gases. Even though overall fuel consumption is increased it is more than compensated with electricity generation increase. In the modelled scenarios, efficiencies of CHP plants of these three scenarios were on the level of 86.58, 86.76 and 88.58% for scenarios A, B and C respectively. This aligns this scenario with modern standards, regulations and environmental sustainability goals, supporting goals for reducing carbon footprints and preserving the environment, especially when compared with

BAU. Next to efficient main energy generation facility these scenarios encompas WtE CHP, solar collectors and heat pumps which further increase overall efficiency of heat, and power, generation.

Scenario D is also based on CHP but encompasses gas turbine paired with Heat Recovery Boilers (HRB). By utilizing three gas turbines in conjunction with Heat Recovery Boilers (HRB), this CHP system substantially increases the amount of thermal energy captured from the exhaust gases produced during the combustion process. The integration of HRBs allows for the efficient recovery of heat for use in DHS, which significantly enhances the overall efficiency of the system. This efficient energy recovery reduces overall fuel consumption, making the system not only economically viable but also environmentally responsible by lowering greenhouse gas emissions. In the modelled scenarios, efficiency of CHP plant in the D scenario was on the level of 80.31%. Next to efficient main energy generation facility this scenario also encompasses WtE CHP, solar collectors and heat pumps which further increase overall efficiency of heat, and power, generation.

The variant utilizing CHP gas engines in combination with a Thermal Energy Storage (TES), renewable energy sources and WtE plant is analysed in the **Scenario E**. It combines exceptional flexibility, modularity, and ability to adapt to diverse energy needs, while optimizing costs and resources, but shows lower efficiency values when compared to either old Steam Power Generation based CHP units or new Combined Cycle Power Genration CHP system. Even though the advantages of this technology which lies in its modularity (each gas engine operates as an independent unit, allowing for capacity adjustment according to actual needs by adding or shutting down individual engines, which enables optimization of production according to current demand, reducing operational costs and optimizing fuel consumption as well as opens possibility of co-firing hydrogen with natural gas) modelled efficiency of E scenario is on the level of 75.55%. It enables lowering of greenhouse gas emissions as well as co-firing hydrogen with natural gas in the future, enhancing sustainability by reducing carbon emissions and progressing towards full decarbonization, while maintaining system flexibility and efficiency in line with climate neutrality goals.

Scenario F is based only on WtE CHP plant while integrating also, solar collectors, heat pumps and electric boilers for covering remaining heat demand. The variant based exclusively on renewable energy sources has been selected for further techno-economic analysis due to its capability to fully meet energy needs using sustainable resources, which is crucial for achieving long-term environmental sustainability and reducing emissions. This system combines a Waste-to-Energy (WtE) plant, solar collectors, heat pumps, electric boilers and a Thermal Energy Storage (TES) system to ensure a reliable energy supply with minimal environmental impact.

In the context of meeting national targets regarding climate change mitigation, all considered scenarios lead to CO_2 emissions reduction due to the use of CHP technologies with highest efficiencies. This is further boosted through the integration of Thermal Energy Storage (TES) systems to ensure a reliable energy supply, enable optimisation of operation of these plants and ensure minimisation of environmental impacts.

On the other hand, these scenarios also integrate renewable energy sources which would enable Moldova to increase the share of renewable energy in gross final energy consumption. Even though this is helping in boosting overall renewable energy share, Moldova already overreached set target in heating and cooling sector, while contributions from renewable energy in electricity generation and transport remain notably low, highlighting these later areas for further development.

7. Financial Model and Economic Analysis for the Project

7.1 Structure of the Financial Model

The financial analysis of the selected investment model has been conducted in accordance with the proposed investment strategy. The analysis covers a 5-year investment period and 21 operational years. Its objective is to evaluate the project's sustainability, potential liquidity risks, asset and liability structure, and key financial indicators. In addition, a comparison of costs and revenues was made against the business-as-usual (BAU) scenario to assess the financial advantages of the proposed investment relative to maintaining current operations.

The financial model, developed in MS Excel, is structured to integrate scenario-based inputs from the techno-economic model, ensuring alignment with the technical and economic framework. It incorporates cost estimations, revenue forecasts, and financial projections for both the selected investment scenario and the BAU scenario. The model is designed for flexibility, allowing for easy scenario analysis and enabling users to assess different financing structures.

The financial model assumes that the project will be financed through a combination of 25% equity and 75% debt. The loan is structured with a 20-year repayment period and an interest rate of 2.5%. These financing assumptions are integrated into the model, influencing cash flow projections, debt servicing calculations, and overall financial viability. In the BAU scenario, specific investments necessary for ensuring the continued operation of existing units have also been considered, with interest rate also 2.5% and 10-year repayment period.

An incremental analysis was conducted by comparing the incremental costs (capital and recurrent) of the project with incremental revenues and savings that are expected to generate. Certain accounting categories that represent present costs and are not going to be changed have been excluded from the incremental analysis as they remain consistent across both the BAU and the new scenario.

The financial statements have been prepared to provide insights into financial health of the selected model, and financial ratios have been calculated.

Table 7-1. Income statement CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] for every fifth year

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	Unit	2030	2035	2040	2045	2050
Operating revenues	EUR	296,612,301	302,447,036	304,257,376	349,963,356	386,020,461
Total revenues	**EUR**	**296,612,301**	**302,447,036**	**304,257,376**	**349,963,356**	**386,020,461**
Operating costs	EUR	247,349,683	249,114,434	251,761,561	291,468,468	317,939,740
Total costs	**EUR**	**247,349,683**	**249,114,434**	**251,761,561**	**291,468,468**	**317,939,740**
EBITDA	**EUR**	**49,262,618**	**53,332,602**	**52,495,815**	**58,494,888**	**68,080,721**
Depreciation and amortization	EUR	14,668,169	14,668,169	9,749,569	9,749,569	8,729,569
EBIT	**EUR**	**34,594,450**	**38,664,433**	**42,746,247**	**48,745,319**	**59,351,152**
Interests	EUR	6,409,162	5,090,348	3,598,230	1,910,036	0
EBT	**EUR**	**28,185,288**	**33,574,086**	**39,148,016**	**46,835,283**	**59,351,152**
Income tax	EUR	3,382,235	4,028,890	4,697,762	5,620,234	7,122,138
NET PROFIT/LOSS	**EUR**	**24,803,053**	**29,545,195**	**34,450,254**	**41,215,049**	**52,229,014**

Table 7-2. Cash flow statement CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] for investment years and every fifth year

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	Unit	2025	2026	2027	2028	2029
EBITDA	**EUR**	0	0	0	0	0
Working capital	EUR					
FUNDS FROM OPERATIONS	EUR	0	0	0	0	0
CAPEX	EUR	7,728,000	5,951,400	75,175,400	112,769,400	140,197,768
FREE CASH FLOW	**EUR**	**-7,728,000**	**-5,951,400**	**-75,175,400**	**-112,769,400**	**-140,197,768**
Equity contribution	EUR	7,728,000	5,951,400	71,776,092	0	0
Disbursement loan	EUR	0	0	3,399,308	112,769,400	140,197,768
Income tax payments	EUR	0	0	0	0	0
CASH-FLOW BEFORE DEBT SERVICE	**EUR**	**0**	**0**	**0**	**0**	**0**
Reimbursement of loan	EUR	0	0	0	0	0
Interest payment	EUR	0	0	0	0	0
NET CASH-FLOW	**EUR**	**0**	**0**	**0**	**0**	**0**
Cash in hand at the end of the year	EUR	0	0	0	0	0

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	Unit	2030	2035	2040	2045	2050
EBITDA	**EUR**	49,262,618	53,332,602	52,495,815	58,494,888	68,080,721
Working capital	EUR	35,295	52,943	794,138	529,425	0
FUNDS FROM OPERATIONS	EUR	49,227,323	53,279,659	51,701,677	57,965,462	68,080,721
CAPEX	EUR					
FREE CASH FLOW	**EUR**	**49,227,323**	**53,279,659**	**51,701,677**	**57,965,462**	**68,080,721**
Equity contribution	EUR					
Disbursement loan	EUR	0	0	0	0	0
Income tax payments	EUR	3,382,235	4,028,890	4,697,762	5,620,234	7,122,138
CASH-FLOW BEFORE DEBT SERVICE	**EUR**	**45,845,089**	**49,250,769**	**47,003,915**	**52,345,228**	**60,958,583**
Reimbursement of loan	EUR	10,036,011	11,354,826	12,846,943	14,535,137	0
Interest payment	EUR	6,409,162	5,090,348	3,598,230	1,910,036	0
NET CASH-FLOW	**EUR**	**29,399,915**	**32,805,595**	**30,558,742**	**35,900,055**	**60,958,583**
Cash in hand at the end of the year	EUR	29,399,915	185,889,816	337,928,809	508,914,996	732,998,927

Table 7-3. Balance sheet CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] for investment years and every fifth year

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	Unit	2025	2026	2027	2028	2029
Gross fixed asset	EUR	7,728,000	13,679,400	88,854,800	201,624,200	317,087,000
less depreciation and amortization	EUR	0	0	0	0	0
NET FIXED ASSETS	**EUR**	**7,728,000**	**13,679,400**	**88,854,800**	**201,624,200**	**317,087,000**
Cash in hand	EUR	0	0	0	0	0
Working capital	EUR					24,734,968
CURRENT ASSETS		**0**	**0**	**0**	**0**	**24,734,968**
TOTAL ASSETS	**EUR**	**7,728,000**	**13,679,400**	**88,854,800**	**201,624,200**	**341,821,968**
Shareholders' contribution	EUR	7,728,000	13,679,400	85,455,492	85,455,492	85,455,492
Retained earnings	EUR	0	0	0	0	0
EQUITY	**EUR**	**7,728,000**	**13,679,400**	**85,455,492**	**85,455,492**	**85,455,492**
Loans	EUR	0	0	3,399,308	116,168,708	256,366,476
LIABILITIES	**EUR**	**0**	**0**	**3,399,308**	**116,168,708**	**256,366,476**
TOTAL EQUITY AND LIABILITIES	**EUR**	**7,728,000**	**13,679,400**	**88,854,800**	**201,624,200**	**341,821,968**

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	Unit	2030	2035	2040	2045	2050
Gross fixed asset	EUR	317,087,000	317,087,000	317,087,000	317,087,000	317,087,000
less depreciation and amortization	EUR	14,668,169	88,009,011	156,431,254	205,179,097	252,906,940
NET FIXED ASSETS	**EUR**	**302,418,831**	**229,077,989**	**160,655,746**	**111,907,903**	**64,180,060**
Cash in hand	EUR	29,399,915	185,889,816	337,928,809	508,914,996	732,998,927
Working capital	EUR	24,770,263	24,964,386	25,970,294	29,676,272	31,793,974
CURRENT ASSETS		**54,170,179**	**210,854,202**	**363,899,104**	**538,591,269**	**764,792,901**
TOTAL ASSETS	**EUR**	**356,589,010**	**439,932,190**	**524,554,849**	**650,499,171**	**828,972,961**
Shareholders' contribution	EUR	85,455,492	85,455,492	85,455,492	85,455,492	85,455,492
Retained earnings	EUR	24,803,053	162,217,621	308,017,092	503,177,361	743,517,469
EQUITY	**EUR**	**110,258,545**	**247,673,113**	**393,472,584**	**588,632,853**	**828,972,961**
Loans	EUR	246,330,465	192,259,077	131,082,265	61,866,318	0
LIABILITIES	**EUR**	**246,330,465**	**192,259,077**	**131,082,265**	**61,866,318**	**0**
TOTAL EQUITY AND LIABILITIES	**EUR**	**356,589,010**	**439,932,190**	**524,554,849**	**650,499,171**	**828,972,961**

The analysis of key financial ratios suggests that the company is in a stable financial position, with positive trends in profitability, liquidity and leverage. The main ratios are within or above reference values, showing a healthy business and the ability to meet obligations.

Table 7-4. Main financial ratios CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] for every fifth year

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]	2030	2035	2040	2045	2050
Return on assets (ROA)	9.70%	8.79%	8.15%	7.49%	7.16%
Return on equity (ROE)	22.50%	11.93%	8.76%	7.00%	6.30%
Debt to equity ratio	2.23	0.78	0.33	0.11	0.00
Total debt ration	0.69	0.44	0.25	0.10	0.00
Debt service coverage	3.00	3.24	3.19	3.56	
Gross profit margin	16.61%	17.63%	17.25%	16.71%	17.64%
Net profit margin	8.36%	9.77%	11.32%	11.78%	13.53%

The analysis indicates that the project achieves substantial cost reduction, the projected IRR demonstrates the project's financial sustainability. The incremental analysis confirms that the benefits of the project outweigh its costs, making it a financially viable investment.

Table 7-5. Incremental analysis CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] for investment years and every fifth year

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] - BAU	Unit	1 2025	2 2026	3 2027	4 2028	5 2029
Revenue from sales (incremental)	**EUR**	**0**	**0**	**0**	**0**	**0**
Revenue from sales - project	EUR	0	0	0	0	0
Revenue from sales - BAU	EUR			0	0	0
Cost of sales (incremental)	**EUR**	**0**	**0**	**0**	**0**	**0**
Cost of sales - project	EUR	0	0	0	0	0
Cost of sales - BAU	EUR			0	0	0
EBITDA	**EUR**	**0**	**0**	**0**	**0**	**0**
Depreciation and Amortization	**EUR**					
Depreciation and Amortization - project	EUR					
Depreciation and Amortization - BAU	EUR					
EBIT	**EUR**	**0**	**0**	**0**	**0**	**0**
Interests	**EUR**					
Interest - project	EUR					
Interest - BAU	EUR					
EBT	**EUR**	**0**	**0**	**0**	**0**	**0**
Income tax	**EUR**					

Income tax - project	EUR					
Income tax - BAU	EUR					
NET PROFTI/LOSS	**EUR**	**0.0**	**0**	**0**	**0**	**0**
EBITDA	**EUR**	**0**	**0**	**0**	**0**	**0**
Depreciation and Amortization	EUR	0	0	0	0	0
Residual value	EUR					
CAPEX	EUR	7,728,000	5,951,400	75,175,400	112,769,400	140,197,768
Income tax	**EUR**	**0**	**0**	**0**	**0**	**0**
NET CASH FLOW	**EUR**	**-7,728,000**	**-5,951,400**	**-75,175,400**	**-112,769,400**	**-140,197,768**
Discounted net cash flow	EUR	-7,360,000	-5,398,095	-64,939,337	-92,775,664	-109,848,620
Cumulated discounted net cash flow	EUR	-7,360,000	-12,758,095	-77,697,432	-170,473,097	-280,321,717

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] - BAU		6	11	16	21	26
	Unit	**2030**	**2035**	**2040**	**2045**	**2050**
Revenue from sales (incremental)	**EUR**	**230,087,647**	**242,028,524**	**235,530,988**	**284,247,229**	**312,180,994**
Revenue from sales - project	EUR	496,421,697	500,618,440	489,077,286	585,954,730	646,448,734
Revenue from sales - BAU	EUR	266,334,049	258,589,916	253,546,298	301,707,500	334,267,740
Cost of sales (incremental)	**EUR**	**94,299,503**	**101,151,123**	**105,667,504**	**111,541,946**	**113,962,520**
Cost of sales - project	EUR	287,233,223	287,986,939	289,250,604	333,434,064	361,512,278
Cost of sales - BAU	EUR	192,933,721	186,835,816	183,583,101	221,892,118	247,549,758
EBITDA	**EUR**	**135,788,145**	**140,877,401**	**129,863,484**	**172,705,283**	**198,218,474**
Depreciation and Amortization	**EUR**	**14,668,169**	**13,668,169**	**5,749,569**	**4,749,569**	**8,729,569**
Depreciation and Amortization - project	EUR	14,668,169	14,668,169	9,749,569	9,749,569	8,729,569
Depreciation and Amortization - BAU	EUR	0	1,000,000	4,000,000	5,000,000	0
EBIT	**EUR**	**121,119,976**	**127,209,232**	**124,113,916**	**167,955,715**	**189,488,905**
Interests	**EUR**	**6,034,162**	**3,766,288**	**2,626,050**	**1,710,976**	**0**
Interest - project	EUR	6,409,162	5,090,348	3,598,230	1,910,036	0
Interest - BAU	EUR	375,000	1,324,060	972,180	199,060	0
EBT	**EUR**	**115,085,814**	**123,442,944**	**121,487,866**	**166,244,738**	**189,488,905**
Income tax	**EUR**	**13,810,298**	**14,813,153**	**14,578,544**	**19,949,369**	**22,738,669**
Income tax - project	EUR	22,573,337	23,144,758	22,377,466	28,903,327	33,144,826

CHP (type 2) [3 x SGT800 + 3 x HRSB + ST] - BAU		6	11	16	21	26
	Unit	2030	2035	2040	2045	2050
Income tax - BAU	EUR	8,763,039	8,331,605	7,798,922	8,953,959	10,406,158
NET PROFTI/LOSS	**EUR**	**101,275,517**	**108,629,791**	**106,909,322**	**146,295,370**	**166,750,236**
EBITDA	**EUR**	**135,788,145**	**140,877,401**	**129,863,484**	**172,705,283**	**198,218,474**
Depreciation and Amortization	EUR	14,668,169	13,668,169	5,749,569	4,749,569	8,729,569
Residual value	EUR					39,180,060
CAPEX	EUR	-20,000,000	-60,000,000	-20,000,000	0	0
Income tax	**EUR**	**13,810,298**	**14,813,153**	**14,578,544**	**19,949,369**	**22,738,669**
NET CASH FLOW	**EUR**	**156,646,016**	**199,732,416**	**141,034,509**	**157,505,483**	**223,389,434**
Discounted net cash flow	EUR	116,891,669	116,779,407	64,609,534	56,535,391	62,826,208
Cumulated discounted net cash flow	EUR	-163,430,048	332,695,007	677,116,937	963,727,868	1,241,036,572

NPV	**1,241,036,572**
IRR	**33%**

The financial modal developed for this project provides framework for decision-making. It provides understanding of the financial implications of the selected modal and supports the strategic objectives of the project. The findings suggest that the project is financially feasible and aligns with the investment strategy.

7.2 Structure of Economic and Technical Model

The structure of the model is pre-defined in the "Request for Proposals" document (file: RFP_no 9134-B1.6_05.05.2023-as issued-Colenco-Ekonerg.pdf).

A visual representation of the model's structure, illustrating the relationship between input data and key outputs, ensuring transparency and clarity in the modeling process is provided in the referenced image (Figure 7-1).

The model's inputs comprise several critical elements:

- Plant level accounting data
- Forecasted inflation
- Forecasted sales
- Termoelectrica's accounting data
- Forecasted currency exchange
- Forecasted fuel and maintenance costs
- Energy model data
- Forecasted salary

- Tariff adjustments

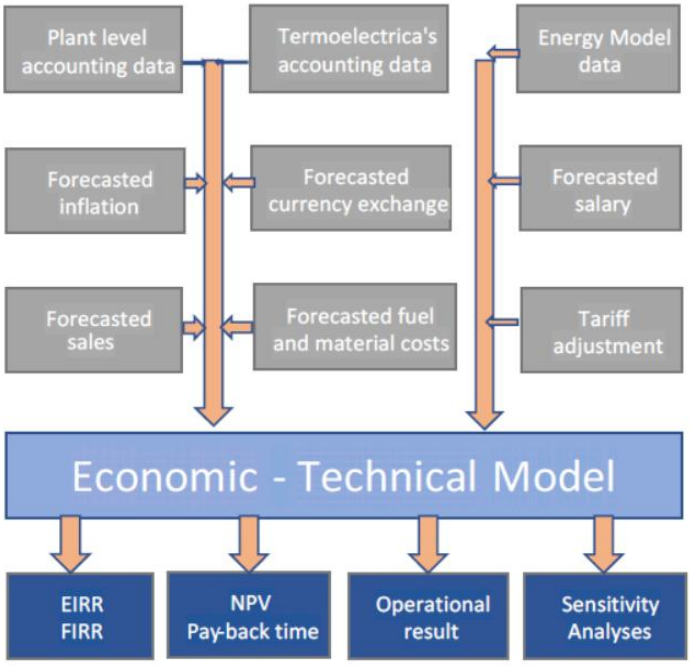


Figure 7-1. Structure of the Economic and Technical Model

These inputs provide the foundational data necessary for accurate modeling and forecasting. The **Plant Level Accounting Data** and **Termoelectrica's Accounting Data** offer a detailed view of the financial and operational status of the production facilities. The **Energy Model Data**, derived from the earlier phase of analysis, integrates essential energy production metrics into the economic and technical model.

The **Forecasted Inflation**, **Currency Exchange Rates**, **Fuel** and **Material Costs**, and **Salaries** provide critical economic indicators that influence cost projections and revenue calculations. These variables allow the model to adapt to future economic conditions. **Tariff Adjustments**, as determined by market dynamics and regulatory requirements, ensure accurate financial outcomes.

The model's output focuses on several crucial projections and analyses. These include:

- Economic Indicators, such as the Economic Internal Rate of Return (EIRR) and Financial Internal Rate of Return (FIRR), which measure the viability of the proposed projects.
- Net Present Value (NPV) and Payback Time, which provide insights into the financial feasibility and investment recovery periods.
- Operational Results, summarizing the expected financial and technical performance of the facilities under study.
- Sensitivity Analyses, which evaluate the impact of changes in input parameters, enabling the identification of risks and areas requiring optimization.

This structured approach ensures that the model not only delivers reliable forecasts but also supports informed decision-making for stakeholders. By integrating technical and financial data, it facilitates strategic planning for investment, operational efficiency, and policy compliance.

7.2.1 Short Description of the Economic and Technical Model Functionality

7.2.1.1 General

The Economic and Technical Model, developed in Microsoft Excel, integrates various input data and assumptions to evaluate the financial and operational performance of the energy project. It provides a comprehensive framework for projecting key financial metrics, estimating revenues and costs, and analysing profitability under different scenarios.

This model ensures a robust and detailed approach to assessing project feasibility and optimizing decision-making processes.

7.2.1.2 Import Results from the Energy Model

The Economic and Technical Model incorporates critical outputs from the Energy Model, including heat production, electricity generation, fuel consumption, and CO_2 emissions. These results form the foundation for calculating operational costs, revenues, and environmental impact, ensuring a seamless connection between technical performance and economic evaluation. Users can import data directly into the model, streamlining the analysis process and maintaining consistency across assessments.

7.2.1.3 Macroeconomic Data Assumptions

To ensure accurate financial projections, the model relies on several macroeconomic data assumptions, such as:

- Inflation Rates: Used to adjust future costs and revenues.
- Profit Tax: Assumed rates based on local or regional regulations, impacting the net profitability of the project.
- Currency Exchange Rates: Critical for projects involving international investments or fuel imports.
- Market Trends: Including forecasts for fuel (natural gas), electricity, heat and CO2 prices.

These assumptions can be customized by the user, allowing for flexibility in addressing specific market conditions.

7.2.1.4 Capital Expenditures Estimation

Capital Expenditures (CAPEX) are estimated based on the costs of constructing new production units, and implementing supporting infrastructure. The model enables users to input specific costs for each component, ensuring detailed and accurate CAPEX calculations. These costs are categorized into:

- Land Acquisition: Costs associated with purchasing or leasing land for the project.
- Engineering and Procurement: Expenses related to the design, planning, and sourcing of materials and equipment.
- Civil and Structural Works: Construction costs for buildings, foundations, and other structural components.
- CHP Unit: Capital investment in the Combined Heat and Power (CHP) unit, including equipment and installation.

- Dry Cooling Towers: Costs for cooling systems that use minimal water resources, ensuring efficiency and environmental compliance.
- Thermal Energy Storage: Investment in infrastructure for storing thermal energy, allowing for demand balancing and operational flexibility.
- Electrical Connection: Costs for connecting the facility to the electrical grid, including transformers and transmission lines.
- Installation and Commissioning: Expenses for assembling, testing, and initiating operations of the equipment and systems.
- Contingencies: Allocated funds to cover unexpected expenses or cost overruns during project implementation.
- Working Capital: Funds needed to support the day-to-day operational requirements of the project once it becomes operational.

The CAPEX estimation serves as a cornerstone for financial feasibility analysis.

7.2.1.5 Depreciation and Amortization Estimation

Depreciation and amortization schedules are calculated for all capital investments, ensuring compliance with accounting standards. The model envisaged straight line depreciation method but allows user to set a different asset lifespan. These calculations impact financial statements and tax obligations, playing a crucial role in determining project profitability.

7.2.1.6 Operational Expenditures Estimation

Operational Expenditures (OPEX) are broken down into fixed and variable costs:

Fixed Costs:

- Maintenance: Costs for regular upkeep of equipment and infrastructure to ensure uninterrupted operations.
- Insurance: Expenses to cover risks associated with assets and operations.
- Labour: Salaries and benefits for employees directly involved in operations.
- Administration: Overheads such as management salaries, office expenses, and professional services.
- Utilities: Expenses for electricity, water, and wastewater services required for the facility's functioning.

Variable Costs:

- Fuel Consumption: Costs associated with the primary fuels used for energy production, such as natural gas or RDF.
- CO_2 Emissions: Expenses linked to carbon pricing mechanisms, such as emissions trading schemes or carbon taxes.
- Electricity for Compressor Station: Energy costs for operating auxiliary systems, such as compressors or pumps.

- Other Consumables: Costs for inputs like chemicals, lubricants, and spare parts that vary with production levels.

The model integrates data from the Energy Model to calculate fuel costs and aligns OPEX projections with operational scenarios, ensuring precision in cost forecasting. This detailed breakdown enables users to identify cost drivers and optimize operational efficiency.

7.2.1.7 Revenue Estimation

Revenue projections are based on three key sources:

- Electricity Sales: Revenue from the sale of electricity produced by the facility. The model allows users to input electricity prices and production volumes for accurate calculations.
- Heat Sales: Revenue generated from supplying heat to district heating network. Tariffs for heat sales can be adjusted within the model to reflect market or regulatory conditions.
- Waste Treatment Revenue (in the case of Waste-to-Energy facilities): Income from processing waste materials. Users can input waste treatment fees (Gate Fee) per ton to estimate this additional revenue stream.

The model also provides an option to include incentivized electricity prices. If enabled, the model applies higher tariffs for electricity generated in the mode of operation without condensation, reflecting potential subsidies or support mechanisms.

7.2.1.8 Profitability Calculation

Profitability is calculated using key financial indicators, including:

- Net Present Value (NPV): Evaluating the project's long-term value.
- Internal Rate of Return (IRR): Measuring investment efficiency.
- Simple Payback Period: Calculating the time required to recover the initial investment based on cash flow without discounting.
- Discounted Payback Period: Determining the time needed to recover the investment, accounting for the time value of money using a discount rate.

The profitability analysis is based on the project's free cash flow, incorporating both the investment and operational periods. Discount rate, of typical 5% was used. This approach ensures a comprehensive assessment of the project's financial sustainability over its entire lifecycle.

7.2.2 Energy and CO_2 prices assumptions

7.2.2.1 Electricity, natural gas, and CO_2 prices projections

It is important to highlight that there are two distinct potential selling prices for electricity: the market price and the incentivized price. The market price, which can fluctuate hourly, applies to electricity generated in non-cogeneration mode (commonly referred to as full condensation mode). On the other hand, the incentivized price is determined by the regulatory authority based on a predefined methodology and is applicable to electricity produced in cogeneration mode (simultaneous production of electricity and heat).

7.2.2.2 Prices projections

The model's projections for future natural gas and CO_2 prices up to 2050 are based on estimates from official documents published by the European Commission: ***"Recommended parameters for reporting on GHG projections in 2023",*** *Version after consultation of WG2 under the Climate Change Committee on 10 March 2022, sharing of draft recommendation on 30 March 2022 and consultation of National Experts designated by members of WG2 on 26 April 2022*.

Table 7-6. Natural gas and CO2 prices projection

Year	Carbon price		Natural gas (NVC)		
	EUR/t_{CO2} (WEM)	EUR/t_{CO2} (WAM)	EUR/MWh_{NG}	EUR/MWh_{NG} (with CO_2) (WEM)	EUR/MWh_{NG} (with CO_2) (WAM)
2027	80,00	80,00	44,78	62,40	62,40
2028	80,00	80,00	43,42	61,03	61,03
2029	80,00	80,00	42,05	59,66	59,66
2030	80,00	80,00	40,68	58,30	58,30
2031	80,40	80,00	40,68	58,38	58,30
2032	80,80	80,00	40,68	58,47	58,30
2033	81,20	80,00	40,68	58,56	58,30
2034	81,60	80,00	40,68	58,65	58,30
2035	82,00	120,00	40,68	58,74	67,10
2036	82,60	146,00	40,68	58,87	72,83
2037	83,20	172,00	40,68	59,00	78,55
2038	83,80	198,00	40,68	59,13	84,28
2039	84,40	224,00	40,68	59,26	90,00
2040	85,00	250,00	40,68	59,40	95,73
2041	94,00	272,00	40,68	61,38	100,57
2042	103,00	294,00	40,68	63,36	105,42
2043	112,00	316,00	40,68	65,34	110,26
2044	121,00	338,00	40,68	67,32	115,11
2045	130,00	360,00	40,68	69,31	119,95
2046	136,00	370,00	41,04	70,99	122,51
2047	143,50	382,50	41,49	73,09	125,72
2048	153,50	399,17	42,09	75,89	129,99
2049	168,50	424,17	42,99	80,09	136,39
2050	160,00	410,00	42,48	77,71	132,76

CO_2 prices are defined for two different scenarios: "WAM" and "WEM"
"WAM" (With Additional Measures) and "WEM" (With Existing Measures) are two approaches for modelling CO_2 emissions, often used in climate and energy planning. WEM is a baseline scenario based on existing policies, while WAM includes both existing and additional planned measures for a more ambitious emissions reduction trajectory.

Market electricity prices, not specified in the above-mentioned European Commission document, are approximated in the model to be twice the price of natural gas. This assumption is based on the typical market efficiency of gas-fired power plants, which operate at approximately 50% efficiency, thus doubling the relative cost of electricity compared to natural gas.

For a comprehensive explanation of this correlation and its foundational logic, please refer to the detailed analysis in the following chapter.

Unlike market electricity prices, incentivized prices for electricity and heat are determined based on a methodology prescribed by the relevant regulatory authority. However, at this stage of the project,

it is not feasible to strictly adhere to the prescribed methodology. Therefore, incentivized prices for electricity and heat have been estimated using the Trend Extrapolation method.

By analysing currently approved prices, it has been observed that electricity prices are approximately 2.4 times higher than the price of natural gas on an MWh basis. Similarly, for heat, the analysis indicates a correlation coefficient of 1.47, meaning that heat is approximately 1.47 times more expensive than natural gas, also on an MWh basis.

Table 7-7. Electric energy and hear prices projection

Electricity				Heat	
Market prices		Incentivised prices		Incentivised prices	
EUR/MWh$_{EE}$ (WEM)	EUR/MWh$_{EE}$ (WAM)	EUR/MWh$_{EE}$ (WEM)	EUR/MWh$_{EE}$ (WAM)	EUR/MWh$_{Heat}$ (WEM)	EUR/MWh$_{Heat}$ (WAM)
124,80	124,80	149,76	149,76	92,10	92,10
122,06	122,06	146,48	146,48	90,08	90,08
119,33	119,33	143,19	143,19	88,06	88,06
116,59	116,59	139,91	139,91	86,04	86,04
116,77	116,59	140,12	139,91	86,17	86,04
116,94	116,59	140,33	139,91	86,30	86,04
117,12	116,59	140,54	139,91	86,43	86,04
117,30	116,59	140,76	139,91	86,56	86,04
117,47	134,21	140,97	161,05	86,69	99,05
117,74	145,66	141,28	174,79	86,89	107,50
118,00	157,11	141,60	188,53	87,08	115,95
118,27	168,56	141,92	202,27	87,28	124,40
118,53	180,01	142,24	216,01	87,47	132,85
118,79	191,46	142,55	229,75	87,67	141,30
122,76	201,15	147,31	241,38	90,60	148,45
126,72	210,84	152,07	253,01	93,52	155,60
130,68	220,53	156,82	264,63	96,45	162,75
134,65	230,22	161,58	276,26	99,37	169,90
138,61	239,90	166,33	287,88	102,30	177,05
141,97	245,03	170,37	294,03	104,78	180,83
146,18	251,43	175,41	301,72	107,88	185,56
151,78	259,97	182,14	311,97	112,01	191,86
160,19	272,78	192,22	327,34	118,22	201,31
155,42	265,52	186,51	318,63	114,70	195,96

7.2.2.3 Correlation between natural gas and market electricity prices, and incentivised electricity prices

The rise in electricity prices (both selling and purchasing) is a consequence of the market organization, where prices are determined by the marginal cost of the last MWh produced. In other words, the most expensive generation unit in operation at any given moment sets the price of electricity, which, in most cases, is production from natural gas.

This relationship is clearly illustrated in the following diagrams.

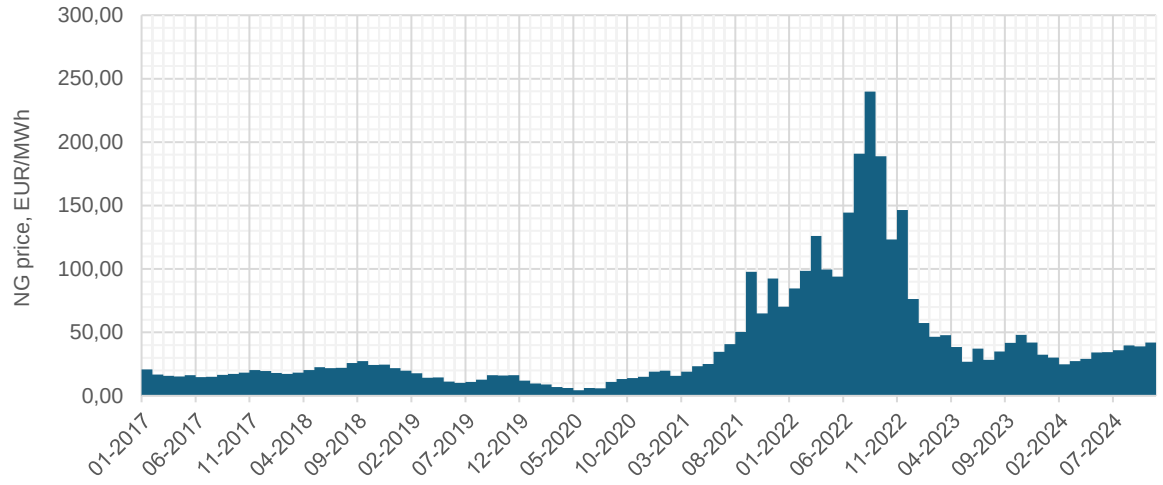


Figure 7-2. Natural gas prices since 2017[33]

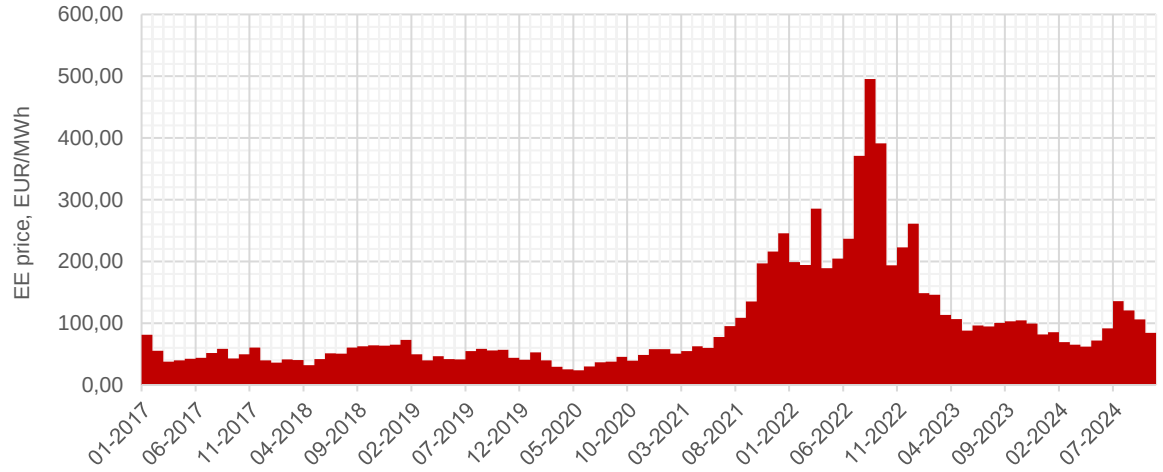


Figure 7-3. Electricity gas prices since 2017[34]

The provided diagrams clearly show that electricity and natural gas prices closely follow each other (when the price of natural gas rises, so too does the price of electricity). This is strong evidence for the claim that the price of electricity is dictated by the price of gas, regardless of the growing share of renewable energy sources.

This trend is expected to persist in the future, as it is unlikely that all gas-fired production units will be completely phased out by the end of the observed period. Therefore, it is reasonable to expect that electricity and natural gas prices will continue to move together, electricity prices typically being twice that of natural gas on a per-MWh basis.

[33] Source: HUPX Hungarian power Exchange (https://hupx.hu/en/market-data/dam/historical-data)
[34] Source: Investing.com Dutch TTF Natural Gas Futures Historical Data (https://www.investing.com/commodities/dutch-ttf-gas-c1-futures-historical-data)

7.2.2.4 Future electricity prices projections as hourly data

Future electricity projections in hourly intervals were used in this analysis, enabling a detailed, time-sensitive analysis of electricity pricing fluctuations over extended periods. This granular projection provides insights into daily and seasonal patterns, helping optimize operational strategies for CHP units, electric boilers, and other components within the energy system based on anticipated electricity market trends.

Given the lack of precise data for Moldova due to its limited and underdeveloped electricity market, the model uses data from the Hungarian Power Exchange (HUPX) as a foundation for forecasting hourly electricity prices. Specifically, 2023 HUPX data was employed, not as concrete values but to establish a correlation between electricity prices at various times of the day. This approach ensures that the projected price series reflects a standardized and consistent pattern observed in a comparable market.

Consequently, the model's hourly price time series was developed using HUPX data, which serves solely to provide the temporal structure, ensuring accurate patterns rather than specific pricing values.

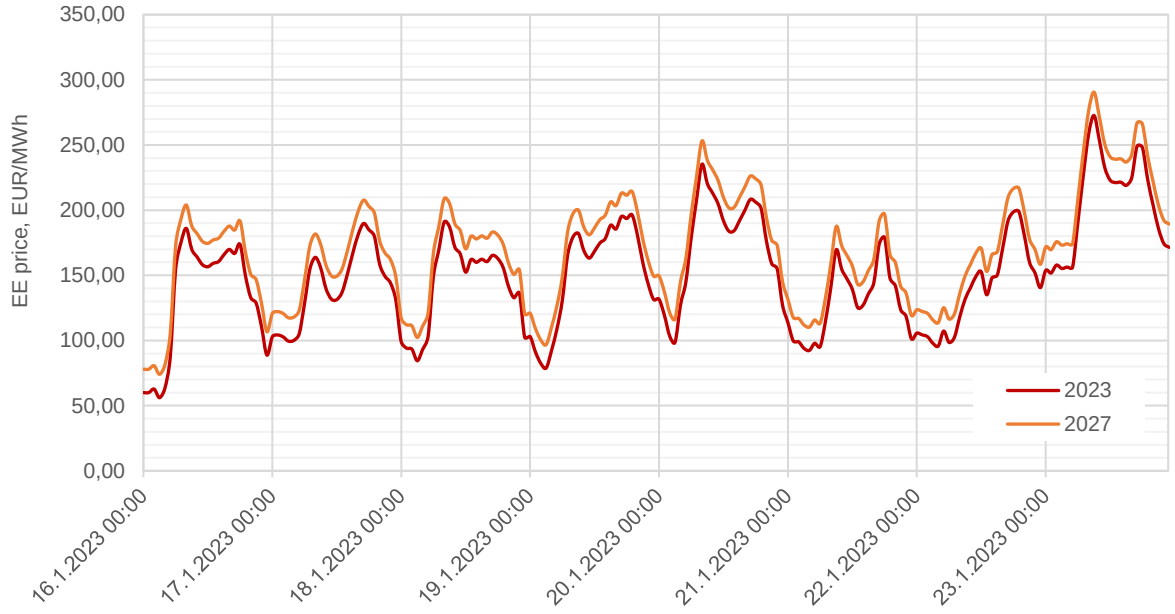


Figure 7-4. DH Comparison between electricity prices in 2023 and the predicted prices for 2027 (Characteristic excerpt 16.01.2023 - 23.01.2023)

7.3 Analysis of Selected Energy System Variants for Optimal District Heating Solutions

7.3.1 Alternatives for the New High Efficiency CHP Plant

The techno-economic analysis was conducted for previously defined alternatives for development of Chisinau DHS. It used the following data and assumptions:

- 26-year period of analysis (5 year of construction, 21 years of exploitation)
- Discount rate: 5 %
- Profit tax rate: 12 %

Considering the conducted economic and financial analysis and depending on the analysed solution, costs and revenues for variants analysed alternative solutions can be calculated.

Analysis of costs and revenues is done by each alternative and presented in following subchapters.

7.3.1.1 CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

7.3.1.1.1 Capital investments

Capital investments encompass the procurement of equipment, as detailed in Chapter 4, along with all associated civil and mechanical works necessary for project implementation. Additionally, they include managerial activities such as commissioning, engineering, and project management. Detailed capital expenditures for each individual CHP production unit are outlined in following table.

Table 7-8. Capital investment - CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	12.804.750	3.841.425	2.560.950	2.560.950	2.560.950	1.280.475
Civil and structural works	EUR	34.120.000	0	0	20.472.000	13.648.000	0
CHP unit	EUR	112.500.000	0	0	22.500.000	45.000.000	45.000.000
Gas turbines	EUR	48.000.000					
HRSB	EUR	20.000.000					
Steam turbine	EUR	22.000.000					
Electrical equipment	EUR	10.000.000					
I&C	EUR	8.000.000					
Auxiliaries	EUR	2.000.000					
Water treatment facility	EUR	2.500.000					
Dry cooling towers	EUR	8.120.000	0	0	1.624.000	3.248.000	3.248.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	7.010.000	0	0	0	1.402.000	5.608.000
Installation and commissioning	EUR	21.680.000	0	0	0	4.336.000	17.344.000
Contingencies	EUR	8.355.000	1.671.000	1.671.000	1.671.000	1.671.000	1.671.000
Working capital	EUR	16.187.209	0	0	0	0	16.187.209
Total	**EUR**	**241.176.959**	**5.512.425**	**4.231.950**	**52.907.950**	**80.025.950**	**98.498.684**

The capital investment including the investment for the reserve fuel reservoirs (for two weeks operation) is presented in the table below.

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	12.804.750	3.841.425	2.560.950	2.560.950	2.560.950	1.280.475
Civil and structural works, and reserve fuel storage	EUR	39.120.000	0	0	23 472 000	15 648 000	0
CHP unit	EUR	112.500.000	0	0	22.500.000	45.000.000	45.000.000
Gas turbines	EUR	48.000.000					
HRSB	EUR	20.000.000					
Steam turbine	EUR	22.000.000					
Electrical equipment	EUR	10.000.000					
I&C	EUR	8.000.000					
Auxiliaries	EUR	2.000.000					
Water treatment facility	EUR	2.500.000					
Dry cooling towers	EUR	8.120.000	0	0	1.624.000	3.248.000	3.248.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	7.010.000	0	0	0	1.402.000	5.608.000
Installation and commissioning	EUR	21.680.000	0	0	0	4.336.000	17.344.000
Contingencies	EUR	8.355.000	1.671.000	1.671.000	1.671.000	1.671.000	1.671.000

Working capital	EUR	16.187.209	0	0	0	0	16.187.209
Total	**EUR**	246 176 959	5 512 425	4 231 950	55 907 950	82 025 950	98 498 684

The investment cost presented in previous Table is based on the latest data obtained directly from equipment manufacturers. These estimates are further validated by extensive expertise and insights gained from previous comparable projects, ensuring a high level of accuracy and reliability in the cost projections.

7.3.1.1.2 Depreciation

Depreciation is a tax-deductible expense that reflects the wear and tear of a fixed asset but does not involve a cash outflow. The calculation is based on the acquisition cost of the fixed asset, including all associated procurement and construction costs. The depreciation period varies depending on the type of asset (e.g., buildings, equipment, etc.) and is defined in accordance with applicable legal regulations.

For this specific case, the depreciation details are presented in the following table, with items clearly categorized by asset type and their prescribed depreciation periods.

Table 7-9. Depreciation - CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

Item	Years	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	10	EUR	12.804.750	1.280.475	1.280.475	...		
Civil and structural works	45	EUR	34.120.000	758.222	758.222	...	758.222	758.222
CHP unit	25	EUR	112.500.000	4.500.000	4.500.000	...	4.500.000	4.500.000
Dry cooling towers	40	EUR	8.120.000	203.000	203.000	...	203.000	203.000
Thermal energy storage	20	EUR	20.400.000	1.020.000	1.020.000	...	1.020.000	
Electrical connection	35	EUR	7.010.000	200.286	200.286	...	200.286	200.286
Installation and commiss.	10	EUR	21.680.000	2.168.000	2.168.000	...		
Contingencies	25	EUR	8.355.000	334.200	334.200	...	334.200	334.200
Total		**EUR**	**224.989.750**	**10.464.183**	**10.464.183**	**...**	**7.015.708**	**5.995.708**

The residual value at the conclusion of the analysis period (year 2050) represents the projected worth of the asset at the end of the evaluation timeframe. Residual value is estimated to 44.195.133 EUR.

7.3.1.1.3 Operating costs

Operating costs are inherently time-dependent and encompass various components, each influenced by specific factors. Certain costs, such as maintenance expenses, are primarily determined by the quality, complexity, and usage of the equipment. These types of operating costs are generally regarded as independent of external factors and are thus classified as **fixed operating costs**. Typical examples include maintenance, insurance, labour, administrative expenses, and utility costs (e.g., electricity, water, and wastewater).

In contrast, other operating costs are significantly influenced by external factors, particularly by fluctuations in energy markets, and are classified as variable operating costs. Fuel expenses, for instance, are directly impacted by market conditions, supply-demand dynamics, and regulatory

frameworks, making them a primary contributor to variability in overall operational expenses. As a result, these types of operating costs are predominantly viewed as **variable operating costs**.

Costs of equipment maintenance

Maintenance costs, as emphasized in the introduction, are determined by the specific characteristics of the equipment and its level of utilization. Broadly, maintenance can be categorized into preventive, corrective, and predictive maintenance, each with varying cost implications. However, these costs can generally be consolidated into two primary components: the cost of the annual overhaul and additional corrective measures, which are directly tied to the number of operational hours of the respective units.

To accurately assess these costs, operational manuals and documentation provided by the equipment manufacturers were thoroughly reviewed. This review focused particularly on defining the recommended number of operational hours between major corrective actions. Using this data, the annual maintenance cost was calculated and is presented in the Table 7-10.

Costs of equipment insurance

Insurance costs are calculated as an annual expense, set at 0.5% of the total capital expenditure (CAPEX). Based on this assumption, the total insurance cost has been determined and is presented in Table 7-10. This table provides a clear overview of the contribution of insurance costs to the overall operational expenses.

Utilities

Utilities refer to essential resources such as electricity, water, and wastewater services, which are integral to the operation of a facility. A defining characteristic of utilities is that they are consumed consistently, regardless of whether the plant is actively operating or temporarily idle. As a result, they are typically classified as fixed operating costs.

Labour cost and cost of administration

The cost of labour is determined based on the number of additional workers required and their estimated annual salaries. The annual salary for workers has been calculated using data from the National Statistics Bureau of Moldova, adjusted to account for projected future salary trends, which have been derived from observable patterns over the past several years. In other words, it is assumed that the additional employees will receive an adjusted average salary consistent with national trends in Moldova.

In addition to the direct costs of workers responsible for the operation of the new unit, an additional administrative expense has been included. This administrative cost is calculated as an annual expense, set at 20% of the total labour expenditure.

Considering these components, the total labour cost is presented in the Table 7-10.

Costs of natural gas

The cost of natural gas, as the primary energy source, remains the most critical factor influencing overall operational expenses, given that it constitutes the largest portion of these costs. Therefore,

both the base price of natural gas and the additional taxes and levies imposed on it are of paramount importance.

Accurately analysing these costs requires a deep understanding of future gas price trajectories, a task that is inherently complex and fraught with uncertainties. Nevertheless, Chapter 7.2.2.1 provides a comprehensive analysis of projected natural gas prices. These forecasts, combined with outputs from the Energy Model, form the basis for calculating the annual cost of natural gas, as detailed in the table Table 7-10, ensuring that the estimates are as robust and informed as possible.

Costs of electricity

Unlike the cost of natural gas, the cost of electricity is more specific and situational. Electricity serves as the primary energy source in only a few selected cases, such as for heat pumps and electric hot water boilers. However, electricity plays a critical supporting role in all CHP units utilizing gas-fired turbines, as additional gas compressors are required due to insufficient gas pressure at the site.

The electricity required for internal consumption, while necessary for the operation, is not explicitly accounted for here. This is because it is deducted from the unit's own electricity production, ensuring that only the net electricity output is considered in the analysis. This approach simplifies the representation while maintaining accuracy in cost evaluation.

Costs of gas emission

The cost of CO_2 emissions is not presented as a separate item, as it is already incorporated into the overall cost of natural gas. For a detailed explanation of this methodology and its rationale, please refer to Chapter 7.2.2.1.

Consumables

Consumables are materials, substances, or items that are regularly consumed, depleted, or require replenishment during plant operations. These include various chemicals, lubricants, oils, filters, emission control consumables, and other similar items. In contrast to utilities, which are typically classified as fixed operating costs, consumables are regarded as variable operating costs because their usage directly depends on the plant's operational intensity and workload.

Table 7-10. Operating costs - CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**6.578.926**	**6.578.926**	**6.578.926**	**6.578.926**	**...**	**6.578.926**	**6.578.926**
Maintenance	EUR	4.732.825	4.732.825	4.732.825	4.732.825	...	4.732.825	4.732.825
Insurance	EUR	1.028.875	1.028.875	1.028.875	1.028.875	...	1.028.875	1.028.875
Labour	EUR	600.000	600.000	600.000	600.000	...	600.000	600.000
Administration	EUR	120.000	120.000	120.000	120.000	...	120.000	120.000
Utilities	EUR	97.226	97.226	97.226	97.226	...	97.226	97.226
Variable Costs	**EUR**	**155.293.164**	**155.523.149**	**155.753.133**	**155.983.117**	**...**	**197.840.267**	**201.290.032**
Natural Gas	EUR	107.159.078	107.159.078	107.159.078	107.159.078	...	107.159.078	107.159.078
CO2 emission	EUR	45.097.429	45.322.916	45.548.403	45.773.891		86.812.551	90.194.858
Electricity for compressor st.	EUR	2.264.054	2.267.407	2.270.760	2.274.113	...	2.884.358	2.934.653
Consumables	EUR	772.603	773.747	774.891	776.035	...	984.280	1.001.443
Total	**EUR**	**161.872.090**	**162.102.074**	**162.332.058**	**162.562.043**	**...**	**204.419.193**	**207.868.958**

7.3.1.1.3.1 Working capital

To maintain operational liquidity and ensure the ability to meet short-term obligations with short-term assets, a defined amount of capital is necessary. In this study, the working capital requirement is estimated at approximately 10% of the operating costs. At the conclusion of the analysis period, the working capital will be fully returned to the investor. Consequently, the cost of working capital is incurred primarily due to the opportunity cost of tying up funds for an extended period.

Table 7-11. Working capital - CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	EUR	0	161.872.090	162.102.074	162.332.058	...	204.419.193	207.868.958
Working capital	EUR	0	16.187.209	16.210.207	16.233.206	...	20.441.919	20.786.896
Cumulative	EUR	0	16.187.209	16.210.207	16.233.206	...	20.441.919	20.786.896
Investment in working capital	**EUR**	**16.187.209**	**22.998**	**22.998**	**22.998**	**...**	**344.977**	
Free working capital	**EUR**					**...**		**20.786.896**

7.3.1.1.4 Project revenues

Revenues are primarily generated through the sale of produced electricity and heat. Consequently, it is essential to accurately determine both the quantities of electricity and heat to be produced and the prices at which these energies will be sold.

Energy production is calculated using an energy model based on heat consumption projections and market prices of electricity. This approach employs the concept of "maximum electricity production," where heat is produced to fully meet local heating demands, while electricity is generated as much as technicaly possible, due to favourable market conditions.

Although the energy model also offers the option of utilizing the " minimal electricity production" approach, the " maximum electricity production" concept was selected. This choice was made based on the future market conditions, where all electricity is produced and sold on electricity market, with no inexpensive and subsidised electricity available locally. Under these circumstances, the "maximum electricity production" strategy is deemed the most reasonable.

Regarding selling prices, the projections detailed in Chapter 7.2.2.1 are used as the basis for calculations. Result for "minimum electricity production" mode is presented in sensitivity analysis (see table Table 8-3).

Table 7-12. Revenues - CHP (type 1) [2 x SGT800 + 2 x HRSB + ST]

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	**158.501.712**	**158.736.448**	**158.971.184**	**...**	**201.927.890**	**205.448.932**
Incentivised production	EUR	76.197.224	78.706.742	75.174.802	...	97.146.852	103.605.422
- incentivised price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	659.146	679.847	648.381	...	659.642	691.440
Market production	EUR	0	0	0	...	0	0
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	0	0	0	...	0	0
Additional production in cond. mode	EUR	82.304.488	80.029.706	83.796.382	...	104.781.038	101.843.510
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	711.977	691.275	722.741	...	711.480	679.682
Heat	**EUR**	**36.712.423**	**39.570.524**	**37.571.517**	**...**	**45.848.476**	**50.294.617**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	420.638	452.714	429.210	...	412.342	444.577
Total	**EUR**	**195.214.135**	**198.306.972**	**196.542.701**	**...**	**247.776.367**	**255.743.549**

7.3.1.1.5 Techno-economic analysis results

It is common practice in project feasibility evaluations to use three fundamental methods:

- Net Present Value (NPV) method
- Internal Rate of Return (IRR) method
- Payback period method

The Net Present Value method is a fundamental financial decision-making criterion. NPV represents the difference between the cumulative cash flows generated during the project observation period and the total investment costs. The term "present value" refers to the process of discounting all cash flows to their present value using a discount rate, ensuring that all cash flows are temporally comparable. Thus, Net Present Value can be defined as the difference between the sum of discounted net cash flows over the entire project observation period and the total investment costs.

A positive NPV indicates a net increase in the project's or company's value, which is desirable from an investor's perspective. Conversely, a negative NPV indicates a net decrease in value, and projects with a negative NPV should be avoided.

The discount rate at which the Net Present Value equals zero over the project observation period is referred to as the Internal Rate of Return (IRR). IRR is the second fundamental criterion for financial decision-making. It is the discount rate that equates the cumulative net cash flows generated during the project observation period to the total investment costs, or the discount rate at which the project's NPV is zero. As a result, a project must achieve at least the IRR equal to the Weighted Average Cost of Capital (WACC), as this serves as the basis for defining the project's NPV. Consequently: Projects expected to yield a positive NPV will also achieve an IRR greater than the cost of capital. Projects yielding a negative NPV will have an IRR lower than the cost of capital.

The Payback Period is a financial metric that measures the amount of time required for an investment or project to generate enough cash flow to recover its initial investment cost.

Table 7-13. Results of Techno-economic analysis for CHP (Type 1) [2 x SGT800 + 2 x HRSB + ST]

NPV	**EUR**	**166.963.846**
IRR	**%**	**11,31**
Payback Period	-	**7,5**

If the investment for the reserve fuel reservoirs will be included in total CAPEX, the financial results are presented in the table below.

Variant with reserve fuel reservoirs		
NPV	EUR	**163.443.196**
IRR	%	**11,06**
Payback Period	-	**7,7**

7.3.1.2 CHP (type 2) [3 × SGT800 + 3 × HRSB + ST]

7.3.1.2.1 Capital investments

Capital investments for the CHP unit (Type 2) are determined using the same methodology and information base as those applied to the previous CHP unit type. The primary distinction between the two-unit types is the inclusion of an additional gas turbine in the design of CHP unit Type 2. This additional turbine not only increases the unit's overall capacity and efficiency but also impacts the scope of required investments, particularly in equipment procurement, installation, and auxiliary systems. Furthermore, this difference necessitates adjustments in associated civil and mechanical

works, commissioning activities, and project management efforts to accommodate the more complex system.

Table 7-14. Capital investment CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	17.766.000	5.329.800	3.553.200	3.553.200	3.553.200	1.776.600
Civil and structural works	EUR	49.680.000	0	0	29.808.000	19.872.000	0
CHP unit	EUR	164.500.000	0	0	32.900.000	65.800.000	65.800.000
Gas turbines	EUR	72.000.000					
HRSB	EUR	30.000.000					
Steam turbine	EUR	30.000.000					
Electrical equipment	EUR	15.000.000					
I&C	EUR	9.000.000					
Auxiliaries	EUR	6.000.000					
Water treatment facility	EUR	2.500.000					
Dry cooling towers	EUR	12.180.000	0	0	2.436.000	4.872.000	4.872.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	9.150.000	0	0	0	1.830.000	7.320.000
Installation and commissioning	EUR	31.420.000	0	0	0	6.284.000	25.136.000
Contingencies	EUR	11.991.000	2.398.200	2.398.200	2.398.200	2.398.200	2.398.200
Working capital	EUR	24.734.968	0	0	0	0	24.734.968
Total	**EUR**	**341.821.968**	**7.728.000**	**5.951.400**	**75.175.400**	**112.769.400**	**140.197.768**

The capital investment including the investment for the reserve fuel reservoirs (for two weeks operation) is presented in the table below.

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	17.766.000	5.329.800	3.553.200	3.553.200	3.553.200	1.776.600
Civil and structural works, and reserve fuel storage	EUR	54.680.000	0	0	32.808.000	21.872.000	0
CHP unit	EUR	164.500.000	0	0	32.900.000	65.800.000	65.800.000
Gas turbines	EUR	72.000.000					
HRSB	EUR	30.000.000					
Steam turbine	EUR	30.000.000					
Electrical equipment	EUR	15.000.000					
I&C	EUR	9.000.000					
Auxiliaries	EUR	6.000.000					
Water treatment facility	EUR	2.500.000					
Dry cooling towers	EUR	12.180.000	0	0	2.436.000	4.872.000	4.872.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	9.150.000	0	0	0	1.830.000	7.320.000
Installation and commissioning	EUR	31.420.000	0	0	0	6.284.000	25.136.000
Contingencies	EUR	11.991.000	2.398.200	2.398.200	2.398.200	2.398.200	2.398.200
Working capital	EUR	24.734.968	0	0	0	0	24.734.968
Total	**EUR**	**346.821.968**	**7.728.000**	**5.951.400**	**78.175.400**	**114.769.400**	**140.197.768**

The capital investment for the Thermal Energy Storage (TES) remains unchanged from that of the previously analysed CHP unit. This consistency arises from the fact that all newly proposed and analysed CHP units are designed to incorporate the same type and size of TES system. The identical TES unit will be implemented across all five types of analysed CHP units, ensuring uniformity in

design, functionality, and performance. Consequently, the capital investment in the TES unit remains identical across all analysed cases simplifying comparative assessments.

7.3.1.2.2 Operating costs, depreciation, working capital, and revenues

The operating costs, depreciation, working capital, and revenues have been determined using the same methodology applied for the CHP Unit (Type 1) and in this chapter the results will be presented in a tabular format only. For further explanations, please refer to Chapter 7.3.1.1.

Table 7-15. Depreciation - CHP (type 2) [3x SGT800 + 3 x HRSB + ST]

Item	Years	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	10	EUR	17.766.000	1.776.600	1.776.600	...		
Civil and structural works	45	EUR	49.680.000	1.104.000	1.104.000	...	1.104.000	1.104.000
CHP unit	25	EUR	164.500.000	6.580.000	6.580.000	...	6.580.000	6.580.000
Dry cooling towers	40	EUR	12.180.000	304.500	304.500	...	304.500	304.500
Thermal energy storage	20	EUR	20.400.000	1.020.000	1.020.000	...	1.020.000	
Electrical connection	35	EUR	9.150.000	261.429	261.429	...	261.429	261.429
Installation and commiss.	10	EUR	31.420.000	3.142.000	3.142.000	...		
Contingencies	25	EUR	11.991.000	479.640	479.640	...	479.640	479.640
Total		**EUR**	**317.087.000**	**14.668.169**	**14.668.169**	**...**	**9.749.569**	**8.729.569**

The residual value at the end of the analysis period (year 2050) is estimated to 64.180.060 EUR.

Table 7-16. Operating costs - CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**9.025.774**	**9.025.774**	**9.025.774**	**9.025.774**	**...**	**9.025.774**	**9.025.774**
Maintenance	EUR	6.713.033	6.713.033	6.713.033	6.713.033	...	6.713.033	6.713.033
Insurance	EUR	1.459.355	1.459.355	1.459.355	1.459.355	...	1.459.355	1.459.355
Labour	EUR	600.000	600.000	600.000	600.000	...	600.000	600.000
Administration	EUR	120.000	120.000	120.000	120.000	...	120.000	120.000
Utilities	EUR	133.386	133.386	133.386	133.386	...	133.386	133.386
Variable Costs	**EUR**	**238.323.909**	**238.676.859**	**239.029.809**	**239.382.760**	**...**	**303.619.712**	**308.913.966**
Natural Gas	EUR	164.453.925	164.453.925	164.453.925	164.453.925	...	164.453.925	164.453.925
CO2 emission	EUR	69.209.715	69.555.763	69.901.812	70.247.860		133.228.701	138.419.429
Electricity for compressor st.	EUR	3.474.578	3.479.724	3.484.870	3.490.016	...	4.426.541	4.503.727
Consumables	EUR	1.185.691	1.187.447	1.189.203	1.190.959	...	1.510.546	1.536.885
Total	**EUR**	**247.349.683**	**247.702.633**	**248.055.583**	**248.408.533**	**...**	**312.645.486**	**317.939.740**

Table 7-17. Working capital - CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	EUR	0	247.349.683	247.702.633	248.055.583	...	312.645.486	317.939.740
Working capital	EUR	0	24.734.968	24.770.263	24.805.558	...	31.264.549	31.793.974
Cumulative	EUR	0	24.734.968	24.770.263	24.805.558	...	31.264.549	31.793.974
Investment in working capital	**EUR**	**24.734.968**	**35.295**	**35.295**	**35.295**	**...**	**529.425**	
Free working capital	**EUR**					**...**		**31.793.974**

Table 7-18. Revenues - CHP (type 2) [3 x SGT800 + 3 x HRSB + ST]

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	**244.178.503**	**244.540.124**	**244.901.745**	**...**	**311.078.343**	**316.502.655**
Incentivised production	EUR	76.197.224	78.706.742	75.174.802	...	97.146.852	103.605.422
- incentivised price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	659.146	679.847	648.381	...	659.642	691.440

Item	Unit	2030	2031	2032	...	2049	2050
Market production	EUR	41.272.913	42.632.217	40.719.109	...	52.620.468	56.118.811
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	357.032	368.245	351.201	...	357.301	374.525
Additional production in cond. mode	EUR	126.708.366	123.201.165	129.007.833	...	161.311.023	156.778.421
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	1.096.093	1.064.178	1.112.689	...	1.095.327	1.046.306
Heat	**EUR**	**52.433.798**	**56.405.390**	**53.550.691**	**...**	**65.244.526**	**69.517.806**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	600.768	645.317	611.753	...	586.782	614.499
Total	**EUR**	**296.612.301**	**300.945.514**	**298.452.435**	**...**	**376.322.869**	**386.020.461**

7.3.1.2.2.1 Techno-economic analysis results

As with the CHP Unit (Type 1), a techno-economic analysis was conducted to determine the key parameters, including NPV, IRR, and Payback Period. For any necessary clarifications or detailed explanations, please refer to Chapter 7.3.1.1.5.

Table 7-19. Results of Techno-economic analysis for CHP (Type 2) [3 x SGT800 + 3 x HRSB + ST]

NPV	EUR	**250.905.532**
IRR	%	**11,65**
Payback Period	-	**7,3**

If the investment for the reserve fuel reservoirs will be included in total CAPEX, the financial results are presented in the table below.

Variant with reserve fuel reservoirs		
NPV	EUR	**247.384.883**
IRR	%	**11,47**
Payback Period	-	**7,4**

7.3.1.3 CHP (type 3) [GT 9G.04 + 1 x HRSB + ST]

7.3.1.3.1 Capital investments

The investment cost for this third type of CHP unit is presented in the following table. As clearly illustrated, the cost structure closely aligns with the framework outlined in previous chapters, enabling straightforward and meaningful comparison across different unit types.

However, it is important to highlight several distinguishing factors in this case. Notably, the proposed gas turbine is significantly larger and classified as a heavy-duty type, which leads to a lower specific price per unit of capacity (per MW) for the turbine itself due to economies of scale.

Additionally, the electric connection costs are substantially higher compared to other unit types. This increase is attributed to the requirement to connect this CHP unit to a grid operating at a higher voltage level, which necessitates more complex and costly infrastructure. These factors have been thoroughly accounted for in the investment analysis to ensure a comprehensive understanding of the financial implications for this type of CHP unit.

Table 7-20. Capital investment CHP (type 3) [GT 9G.04 + HRSB + ST]

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	29.726.288	8.917.886	5.945.258	5.945.258	5.945.258	2.972.629
Civil and structural works	EUR	81.100.000	0	0	48.660.000	32.440.000	0
CHP unit	EUR	273.825.000	0	0	54.765.000	109.530.000	109.530.000
Gas turbine	EUR	115.000.000					
HRSB	EUR	50.825.000					
Steam turbine	EUR	50.000.000					
Electrical equipment	EUR	30.500.000					
I&C	EUR	15.000.000					
Auxiliaries	EUR	10.000.000					
Water treatment facility	EUR	2.500.000					
Dry cooling towers	EUR	18.200.000	0	0	3.640.000	7.280.000	7.280.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	50.275.000	0	0	0	10.055.000	40.220.000

Installation and commissioning	EUR	50.500.000	0	0	0	10.100.000	40.400.000
Contingencies	EUR	20.514.250	4.102.850	4.102.850	4.102.850	4.102.850	4.102.850
Working capital	EUR	38.882.982	0	0	0	0	38.882.982
Total	**EUR**	**583.423.519**	**13.020.736**	**10.048.108**	**121.193.108**	**187.613.108**	**251.548.461**

The capital investment including the investment for the reserve fuel reservoirs (for two weeks operation) is presented in the table below.

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	29.726.288	8.917.886	5.945.258	5.945.258	5.945.258	2.972.629
Civil and structural works, and reserve fuel storage	EUR	91.100.000	0	0	54.660.000	36.440.000	0
CHP unit	EUR	273.825.000	0	0	54.765.000	109.530.000	109.530.000
Gas turbine	EUR	115.000.000					
HRSB	EUR	50.825.000					
Steam turbine	EUR	50.000.000					
Electrical equipment	EUR	30.500.000					
I&C	EUR	15.000.000					
Auxiliaries	EUR	10.000.000					
Water treatment facility	EUR	2.500.000					
Dry cooling towers	EUR	18.200.000	0	0	3.640.000	7.280.000	7.280.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	50.275.000	0	0	0	10.055.000	40.220.000
Installation and commissioning	EUR	50.500.000	0	0	0	10.100.000	40.400.000
Contingencies	EUR	20.514.250	4.102.850	4.102.850	4.102.850	4.102.850	4.102.850
Working capital	EUR	38.882.982	0	0	0	0	38.882.982
Total	**EUR**	**593.423.519**	**13.020.736**	**10.048.108**	**127.193.108**	**191.613.108**	**251.548.461**

7.3.1.3.2 Operating costs, depreciation, working capital, and revenues

Again, the operating costs, depreciation, working capital, and revenues have been determined using the same methodology applied for previous CHP Units (Type 1 and 2) allowing meaningful comparation of analysed of suggested units. Therefore, this chapter will present the results in a tabular format only. For further details or additional explanations, please refer to Chapter 7.3.1.1.

Table 7-21. Depreciation - CHP (type 3) [GT 9G.04 + HRSB + ST]

Item	Years	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	10	EUR	29.726.288	2.972.629	2.972.629	...		
Civil and structural works	45	EUR	81.100.000	1.802.222	1.802.222	...	1.802.222	1.802.222
CHP unit	25	EUR	273.825.000	10.953.000	10.953.000	...	10.953.000	10.953.000
Dry cooling towers	40	EUR	18.200.000	455.000	455.000	...	455.000	455.000
Thermal energy storage	20	EUR	20.400.000	1.020.000	1.020.000	...	1.020.000	
Electrical connection	35	EUR	50.275.000	1.436.429	1.436.429	...	1.436.429	1.436.429
Installation and commiss.	10	EUR	50.500.000	5.050.000	5.050.000	...		
Contingencies	25	EUR	20.514.250	820.570	820.570	...	820.570	820.570
Total		**EUR**	**544.540.538**	**24.509.850**	**24.509.850**	**...**	**16.487.221**	**15.467.221**

The residual value at the end of the analysis period (year 2050) is estimated to 119.102.613 EUR.

Table 7-22. Operating costs - CHP (type 3) [GT 9G.04 + HRSB + ST]

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**14.654.874**	**14.654.874**	**14.654.874**	**14.654.874**	**...**	**14.654.874**	**14.654.874**
Maintenance	EUR	11.268.604	11.268.604	11.268.604	11.268.604	...	11.268.604	11.268.604
Insurance	EUR	2.449.696	2.449.696	2.449.696	2.449.696	...	2.449.696	2.449.696
Labour	EUR	600.000	600.000	600.000	600.000	...	600.000	600.000
Administration	EUR	120.000	120.000	120.000	120.000	...	120.000	120.000
Utilities	EUR	216.574	216.574	216.574	216.574	...	216.574	216.574
Variable Costs	**EUR**	**374.174.943**	**374.729.085**	**375.283.226**	**375.837.368**	**...**	**476.691.109**	**485.003.231**
Natural Gas	EUR	256.836.057	256.836.057	256.836.057	256.836.057	...	256.836.057	256.836.057
CO2 emission	EUR	108.088.331	108.628.772	109.169.214	109.709.656		208.070.037	216.176.661
Electricity for compressor st.	EUR	7.388.989	7.399.932	7.410.875	7.421.818	...	9.413.419	9.577.562
Consumables	EUR	1.861.567	1.864.324	1.867.081	1.869.838	...	2.371.598	2.412.951
Total	**EUR**	**388.829.818**	**389.383.959**	**389.938.101**	**390.492.242**	**...**	**491.345.984**	**499.658.106**

Table 7-23. Working capital - CHP (type 3) [GT 9G.04 + HRSB + ST]

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	EUR	0	388.829.818	389.383.959	389.938.101	**...**	491.345.984	499.658.106
Working capital	EUR	0	38.882.982	38.938.396	38.993.810	...	49.134.598	49.965.811
Cumulative	EUR	0	38.882.982	38.938.396	38.993.810	...	49.134.598	49.965.811
Investment in working capital	**EUR**	**38.882.982**	**55.414**	**55.414**	**55.414**	**...**	**831.212**	

Table 7-24. Revenues - CHP (type 3) [GT 9G.04 + HRSB + ST]

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	**402.146.675**	**402.742.242**	**403.337.808**	**...**	**512.326.515**	**521.260.015**
Incentivised production	EUR	76.197.224	78.706.742	75.174.802	...	97.146.852	103.605.422
- incentivised price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	659.146	679.847	648.381	...	659.642	691.440
Market production	EUR	117.128.512	120.986.083	115.556.871	**...**	149.331.770	159.259.726
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	1.013.222	1.045.045	996.675	...	1.013.986	1.062.865
Additional production in cond. mode	EUR	208820939,2	203049416,2	212606135,5	...	265847893,2	258394866,9
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	1.806.410	1.753.885	1.833.722	...	1.805.149	1.724.472
Heat	**EUR**	**72.721.320**	**74.860.717**	**71.743.943**	**...**	**88.440.686**	**89.060.119**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	833.215	856.459	819.589	...	795.399	787.243
Total	**EUR**	**474.867.995**	**477.602.959**	**475.081.751**	**...**	**600.767.200**	**610.320.134**

7.3.1.3.3 Techno-economic analysis results

As with the CHP Unit (Type 1), a techno-economic analysis was conducted here as well to determine the key parameters, including NPV, IRR, and Payback Period. For any additional clarifications or detailed explanations, please refer to Chapter 7.2.2.2.1.6.

Table 7-25. Results of Techno-economic analysis for CHP (type 3) [GT 9G.04 + HRSB + ST]

NPV	EUR	**410.740.543**
IRR	%	**11,45**
Payback Period	-	**7,5**

If the investment for the reserve fuel reservoirs will be included in total CAPEX, the financial results are presented in the table below.

Variant with reserve fuel reservoirs		
NPV	EUR	**403.699.244**

IRR	%	**11,24**
Payback Period	-	**7,6**

7.3.1.4 CHP (type 4) [3 × GT LM6000 + 3 × HRB + ST]

7.3.1.4.1 Capital investments

The capital investment for this unit is significantly lower, primarily because it does not include a steam turbine, and the heat recovery system is considerably simpler. Instead of producing steam, this unit generates heat in the form of hot water, which reduces the complexity and cost of the heat recovery unit.

On the other hand, the gas turbines employed in this configuration are of the aeroderivative type, which are inherently more expensive per unit of capacity due to their advanced design, higher efficiency, and operational flexibility.

Despite these distinct differences, the overall cost structure remains closely aligned with the framework outlined in previous chapters. This consistency facilitates a straightforward and meaningful comparison across all proposed CHP unit types, ensuring clarity in evaluating their respective investment profiles.

Table 7-26. Capital investment - CHP [3 x GT-LM6000 + 3 x HRB]

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	13.291.320	3.987.396	2.658.264	2.658.264	2.658.264	1.329.132
Civil and structural works	EUR	24.260.000	0	0	14.556.000	9.704.000	0
CHP unit	EUR	130.140.000	0	0	26.028.000	52.056.000	52.056.000
Dry cooling towers	EUR	11.480.000	0	0	2.296.000	4.592.000	4.592.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	7.010.000	0	0	0	1.402.000	5.608.000
Installation and commissioning	EUR	23.320.000	0	0	0	4.664.000	18.656.000
Contingencies	EUR	8.902.000	1.780.400	1.780.400	1.780.400	1.780.400	1.780.400
Working capital	EUR	20.055.702	0	0	0	0	20.055.702
Total	**EUR**	**258.859.022**	**5.767.796**	**4.438.664**	**51.398.664**	**85.016.664**	**112.237.234**

The capital investment including the investment for the reserve fuel reservoirs (for two weeks operation) is presented in the table below.

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	13.291.320	3.987.396	2.658.264	2.658.264	2.658.264	1.329.132
Civil and structural works, and reserve fuel storage	EUR	29.260.000	0	0	17.556.000	11.704.000	0
CHP unit	EUR	130.140.000	0	0	26.028.000	52.056.000	52.056.000
Dry cooling towers	EUR	11.480.000	0	0	2.296.000	4.592.000	4.592.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	7.010.000	0	0	0	1.402.000	5.608.000
Installation and commissioning	EUR	23.320.000	0	0	0	4.664.000	18.656.000
Contingencies	EUR	8.902.000	1.780.400	1.780.400	1.780.400	1.780.400	1.780.400
Working capital	EUR	20.055.702	0	0	0	0	20.055.702
Total	**EUR**	**263.859.022**	**5.767.796**	**4.438.664**	**54.398.664**	**87.016.664**	**112.237.234**

7.3.1.4.2 Operating costs, depreciation, working capital, and revenues

Again, the operating costs, depreciation, working capital, and revenues have been determined using the same methodology applied for previous CHP Units. Again, if additional explanation is needed, please refer to Chapter 7.3.1.1.

Table 7-27. Depreciation - CHP (type 3) CHP [3 x GT-LM6000 + 3 x HRB]

Item	Years	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	10	EUR	13.291.320	1.329.132	1.329.132	...		
Civil and structural works	45	EUR	24.260.000	539.111	539.111	...	539.111	539.111
CHP unit	25	EUR	130.140.000	5.205.600	5.205.600	...	5.205.600	5.205.600
Dry cooling towers	40	EUR	11.480.000	287.000	287.000	...	287.000	287.000
Thermal energy storage	20	EUR	20.400.000	1.020.000	1.020.000	...	1.020.000	
Electrical connection	35	EUR	7.010.000	200.286	200.286	...	200.286	200.286
Installation and commiss.	10	EUR	23.320.000	2.332.000	2.332.000	...		
Contingencies	25	EUR	8.902.000	356.080	356.080	...	356.080	356.080
Total		**EUR**	**238.803.320**	**11.269.209**	**11.269.209**	**...**	**7.608.077**	**6.588.077**

The residual value at the end of the analysis period (year 2050) is estimated to 43.442.387 EUR.

Table 7-28. Operating costs - CHP [3 x GT-LM6000 + 3 x HRB]

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**10.951.334**	**10.951.334**	**10.951.334**	**10.951.334**	**...**	**10.951.334**	**10.951.334**
Maintenance	EUR	8.974.982	8.974.982	8.974.982	8.974.982	...	8.974.982	8.974.982
Insurance	EUR	1.094.510	1.094.510	1.094.510	1.094.510	...	1.094.510	1.094.510
Labour	EUR	600.000	600.000	600.000	600.000	...	600.000	600.000
Administration	EUR	120.000	120.000	120.000	120.000	...	120.000	120.000
Utilities	EUR	161.842	161.842	161.842	161.842	...	161.842	161.842
Variable Costs	**EUR**	**189.605.689**	**189.886.489**	**190.167.289**	**190.448.089**	**...**	**241.553.711**	**245.765.713**
Natural Gas	EUR	130.836.221	130.836.221	130.836.221	130.836.221	...	130.836.221	130.836.221
CO2 emission	EUR	55.061.851	55.337.161	55.612.470	55.887.779	...	105.994.064	110.123.703
Electricity for compressor st.	EUR	2.764.304	2.768.398	2.772.492	2.776.586	...	3.521.666	3.583.074
Consumables	EUR	943.312	944.709	946.106	947.503	...	1.201.760	1.222.715
Total	**EUR**	**200.557.023**	**200.837.823**	**201.118.623**	**201.399.424**	**...**	**252.505.045**	**256.717.047**

Table 7-29. Working capital - CHP [3 x GT-LM6000 + 3 x HRB]

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	EUR	0	200.557.023	200.837.823	201.118.623	...	252.505.045	256.717.047
Working capital	EUR	0	20.055.702	20.083.782	20.111.862	...	25.250.505	25.671.705
Cumulative	EUR	0	20.055.702	20.083.782	20.111.862	...	25.250.505	25.671.705
Investment in working capital	**EUR**	**20.055.702**	**28.080**	**28.080**	**28.080**	**...**	**421.200**	
Free working capital	**EUR**					**...**		**25.671.705**

Table 7-30. Revenues - CHP [3 x GT-LM6000 + 3 x HRB]

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	**151.776.041**	**152.000.817**	**152.225.592**	**...**	**193.359.525**	**196.731.159**
Incentivised production	EUR	72.954.442	75.357.738	71.975.232	...	93.012.519	99.197.374
- incentivised price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	631.094	650.920	620.784	...	631.570	662.022
Market production	EUR	0	0	0	**...**	0	0
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	0	0	0	...	0	0

Item	Unit	2030	2031	2032	...	2049	2050
Additional production in cond. mode	EUR	78821599,51	76643079,11	80250360,56	...	100347006,6	97533785,6
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	681.848	662.022	692.157	...	681.372	650.920
Heat	**EUR**	**52.322.667**	**56.297.746**	**53.441.483**	**...**	**65.116.887**	**69.400.432**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	599.494	644.085	610.505	...	585.634	613.462
Total	**EUR**	**204.098.708**	**208.298.563**	**205.667.075**	**...**	**258.476.413**	**266.131.592**

7.3.1.4.3 Techno-economic analysis results

As with the CHP Unit (Type 1), a comprehensive techno-economic analysis was conducted here as well to determine the key performance parameters, including NPV, IRR, and Payback Period. This analysis provides a robust evaluation of the project's financial viability and its potential to generate returns. The methodology employed ensures consistency across evaluations, allowing for meaningful comparisons between units. For any additional clarifications or detailed explanations regarding the analysis process or assumptions used, please refer to Chapter 7.3.1.1.

Table 7-31. Results of Techno-economic analysis for CHP [3 x GT-LM6000 + 3 x HRB]

NPV	EUR	**-144.901.949**
IRR	%	**-1,91**
Payback Period	-	**-**

If the investment for the reserve fuel reservoirs will be included in total CAPEX, the financial results are presented in the table below.

Variant with reserve fuel reservoirs		
NPV	EUR	**-148.545.126**
IRR	%	**-1,93**
Payback Period	-	**-**

7.3.1.5 CHP (type 5) [Gas engines Jenbacher J920 Flextra x 18]

7.3.1.5.1 Capital investments

The fifth CHP unit type features a configuration with a larger number of gas engines, each equipped with a heat recovery system integrated directly onto the engines. This design achieves the lowest specific cost per unit of energy produced among the analysed units, for several key reasons.

The gas engine is a significantly simpler piece of machinery compared to combined CHP units that incorporate multiple gas turbines and a single steam back-pressure turbine. This simplicity reduces the capital costs associated with the system.

Unlike other configurations, this setup does not require a dry cooling tower. The inclusion of by-pass stacks on all gas engines effectively eliminates the need for additional cooling infrastructure, further reducing costs. The required pressure at the gas supply connection point is considerably lower compared to systems with gas turbines. This means the overall cost of gas auxiliary systems is significantly reduced, as no additional compressor is needed—the available gas pressure at the site is sufficient for the gas engines' requirements. An additional heat recovery unit is unnecessary in this configuration, as the heat recovery system is an integral part of the gas engine and is supplied by the manufacturer upon the buyer's request. This integration streamlines installation and reduces the overall system complexity and cost. These factors collectively make the fifth CHP unit type a

cost-effective and efficient solution, particularly in scenarios where simplicity and lower initial investment are priorities.

Table 7-32. Capital investment (Gas engines [Jenbacher J920 Flextra] x 18)

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	14.498.414	4.349.524	2.899.683	2.899.683	2.899.683	1.449.841
Civil and structural works	EUR	12.756.000	0	0	7.653.600	5.102.400	0
CHP unit	EUR	157.000.000	0	0	31.400.000	62.800.000	62.800.000
Gas engine	EUR	134.500.000					
Electrical equipment	EUR	10.000.000					
I&C	EUR	8.000.000					
Auxiliaries	EUR	2.000.000					
Water treatment facility	EUR	2.500.000					
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	9.910.000	0	0	0	1.982.000	7.928.000
Installation and commissioning	EUR	15.262.000	0	0	0	3.052.400	12.209.600
Contingencies	EUR	7.833.000	1.566.600	1.566.600	1.566.600	1.566.600	1.566.600
Working capital	EUR	21.388.905	0	0	0	0	21.388.905
Total	**EUR**	**259.048.319**	**5.916.124**	**4.466.283**	**47.599.883**	**85.563.083**	**115.502.946**

The capital investment included the investment for the reserve fuel reservoirs (for two weeks operation) is presented in the table below.

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	14.498.414	4.349.524	2.899.683	2.899.683	2.899.683	1.449.841
Civil and structural works, and reserve fuel storage	EUR	17.756.000	0	0	10.653.600	7.102.400	0
CHP unit	EUR	157.000.000	0	0	31.400.000	62.800.000	62.800.000
Gas engine	EUR	134.500.000					
Electrical equipment	EUR	10.000.000					
I&C	EUR	8.000.000					
Auxiliaries	EUR	2.000.000					
Water treatment facility	EUR	2.500.000					
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	9.910.000	0	0	0	1.982.000	7.928.000
Installation and commissioning	EUR	15.262.000	0	0	0	3.052.400	12.209.600
Contingencies	EUR	7.833.000	1.566.600	1.566.600	1.566.600	1.566.600	1.566.600
Working capital	EUR	21.388.905	0	0	0	0	21.388.905
Total	**EUR**	**264.048.319**	**5.916.124**	**4.466.283**	**50.599.883**	**87.563.083**	**115.502.946**

7.3.1.5.2 Operating costs, depreciation, working capital, and revenues

Again, the operating costs, depreciation, working capital, and revenues have been determined using the same methodology applied for previous CHP Units. Again, if additional explanation is needed, please refer to Chapter 7.3.1.1.

Table 7-33. Depreciation - (Gas engines [Jenbacher J920 Flextra] x 18)

Item	Years	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	10	EUR	14.498.414	1.449.841	1.449.841	...		
Civil and structural works	45	EUR	12.756.000	283.467	283.467	...	283.467	283.467

CHP unit	25	EUR	157.000.000	6.280.000	6.280.000	...	6.280.000	6.280.000
Dry cooling towers	40	EUR	0	0	0	...	0	0
Thermal energy storage	20	EUR	20.400.000	1.020.000	1.020.000	...	1.020.000	
Electrical connection	35	EUR	9.910.000	283.143	283.143	...	283.143	283.143
Installation and commiss.	10	EUR	15.262.000	1.526.200	1.526.200	...		
Contingencies	25	EUR	7.833.000	313.320	313.320	...	313.320	313.320
Total		**EUR**	237.659.414	11.155.971	11.155.971	**...**	8.179.930	7.159.930

The residual value at the end of the analysis period (year 2050) is estimated to 37.140.480 EUR.

Table 7-34. Operating costs - (Gas engines [Jenbacher J920 Flextra] x 18)

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**12.631.065**	**12.631.065**	**12.631.065**	**12.631.065**	**...**	**12.631.065**	**12.631.065**
Maintenance	EUR	11.000.000	11.000.000	11.000.000	11.000.000	...	11.000.000	11.000.000
Insurance	EUR	793.185	793.185	793.185	793.185	...	793.185	793.185
Labour	EUR	600.000	600.000	600.000	600.000	...	600.000	600.000
Administration	EUR	120.000	120.000	120.000	120.000	...	120.000	120.000
Utilities	EUR	117.880	117.880	117.880	117.880	...	117.880	117.880
Variable Costs	**EUR**	**201.257.985**	**201.556.042**	**201.854.099**	**202.152.156**	...	**256.398.495**	**260.869.347**
Natural Gas	EUR	140.244.182	140.244.182	140.244.182	140.244.182	...	140.244.182	140.244.182
CO2	EUR	59.021.150	59.316.256	59.611.362	59.906.467	...	113.615.714	118.042.300
Electricity for compressor	EUR	0	0	0	0	...	0	0
Consumables	EUR	1.992.653	1.995.604	1.998.555	2.001.506	...	2.538.599	2.582.865
Total	**EUR**	**213.889.050**	**214.187.107**	**214.485.164**	**214.783.221**	...	**269.029.560**	**273.500.412**

Table 7-35. Working capital - (Gas engines [Jenbacher J920 Flextra] x 18)

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	EUR	0	213 889 050	214 187 107	214 485 164	**...**	269 029 560	273 500 412
Working capital	EUR	0	21 388 905	21 418 711	21 448 516	...	26 902 956	27 350 041
Cumulative	EUR	0	21 388 905	21 418 711	21 448 516	...	26 902 956	27 350 041
Investment in working capital	**EUR**	**21 388 905**	**29 806**	**29 806**	**29 806**	**...**	**447 085**	
Free working capital	**EUR**					**...**		**27 350 041**

Table 7-36. Revenues - (Gas engines [Jenbacher J920 Flextra] x 18)

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	**184.328.292**	**184.601.277**	**184.874.261**	**...**	**234.830.417**	**238.925.184**
Incentivised production	EUR	76.197.224	78.706.742	75.174.802	...	97.146.852	103.605.422
- incentivised price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	659.146	679.847	648.381	...	659.642	691.440
Market production	EUR	12.415.725	12.824.631	12.249.130	**...**	15.829.299	16.881.671
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	107.402	110.776	105.648	...	107.483	112.665
Additional production in cond. mode	EUR	95.715.343	93.069.903	97.450.329	...	121.854.267	118.438.091
- weighted average market price	EUR/MWh	115,60	115,77	115,94	...	147,27	149,84
- production	MWh	827.987	803.912	840.506	...	827.410	790.430
Heat	**EUR**	**55.454.857**	**59.421.194**	**56.484.341**	**...**	**68.904.000**	**72.812.169**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	635.382	679.820	645.266	...	619.694	643.620
Total	**EUR**	**239.783.149**	**244.022.470**	**241.358.602**	**...**	**303.734.417**	**311.737.353**

7.3.1.5.3 Techno-economic analysis results

Similar to the analysis conducted for the CHP Unit (Type 1), a detailed techno-economic assessment was carried out here to evaluate the key financial indicators, including NPV, IRR, and Payback Period. Again, for further details on the methodology or underlying assumptions, please refer to Chapter 7.3.1.1., where additional explanations are provided.

Table 7-37. Results of Techno-economic analysis for Gas engines [Jenbacher J920 Flextra] x 18)

NPV	EUR	**79.469.532**
IRR	%	**8,03**
Payback Period	-	**10,2**

If the investment for the reserve fuel reservoirs will be included in total CAPEX, the financial results are presented in the table below.

Variant with reserve fuel reservoirs		
NPV	EUR	**75.948.882**
IRR	%	**7,84**
Payback Period	-	**10,4**

7.3.2 Complementary Facilities and Technologies for Heat Energy Generation From Renewable Energy Sources, Waste to Energy and Combination With Thermal Energy Storage Facilities

7.3.2.1 Solar Panels

Solar panels constitute a part of a larger investment that combines additional solutions such as electric boilers, waste-to-energy systems, heat pumps, and thermal energy storage (TES). In this chapter, the individual techno-economic feasibility of solar panels is evaluated.

7.3.2.1.1 Capital investments

Capital investment estimation in solar panels is provided in Table 7-38.

Table 7-38. Capital investment (Solar Panels)

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	600.000	180.000	120.000	120.000	120.000	60.000
Civil and structural works	EUR	1.500.000	0	0	900.000	600.000	0
Production unit	EUR	13.000.000	0	0	2.600.000	5.200.000	5.200.000
Dry cooling towers	EUR	0	0	0	0	0	0
Electrical connection	EUR	100.000	0	0	0	20.000	80.000
Installation and commissioning	EUR	1.000.000	0	0	0	200.000	800.000
Contingencies	EUR	810.000	162.000	162.000	162.000	162.000	162.000
Working capital	EUR	41.482	0	0	0	0	41.482
Total	**EUR**	**17.051.482**	**342.000**	**282.000**	**3.782.000**	**6.302.000**	**6.343.482**

7.3.2.1.2 Operating costs, depreciation, working capital, and revenues

Depreciation, operating costs, working capital and revenue estimation for solar panels is provided in Table 7-39 to Table 7-42.

Table 7-39. Depreciation - (Solar Panels)

Item	Rate	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	20%	EUR	600.000	120.000	120.000	...		
Civil and structural works	2%	EUR	1.500.000	30.000	30.000	...	30.000	30.000
Production unit	5%	EUR	13.000.000	650.000	650.000	...	650.000	
Dry cooling towers	5%	EUR	0	0	0	...	0	
Electrical connection	3,33%	EUR	100.000	3.333	3.333	...	3.333	3.333
Installation and commiss.	3,33%	EUR	1.000.000	33.333	33.333	...	33.333	33.333
Contingencies	5%	EUR	810.000	40.500	40.500	...	40.500	
Total		**EUR**	**17.010.000**	**877.167**	**877.167**	**...**	**757.167**	**66.667**

Table 7-40. Operating costs - (Solar Panels)

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	355.000	355.000	355.000	355.000	**...**	355.000	355.000
Maintenance	EUR	85.000	85.000	85.000	85.000	...	85.000	85.000
Insurance	EUR	85.000	85.000	85.000	85.000	...	85.000	85.000
Labour	EUR	150.000	150.000	150.000	150.000	...	150.000	150.000
Administration	EUR	30.000	30.000	30.000	30.000	...	30.000	30.000
Utilities	EUR	5.000	5.000	5.000	5.000	...	5.000	5.000
Variable Costs	**EUR**	59.823	59.912	60.000	60.089	...	76.213	77.542
Electricity for water pump	EUR	57.800	57.886	57.971	58.057	...	73.636	74.920
Consumables	EUR	2.023	2.026	2.029	2.032	...	2.577	2.622
Total	**EUR**	**414.823**	**414.912**	**415.000**	**415.089**	**...**	**431.213**	**432.542**

Table 7-41. Working capital - (Solar Panels)

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	**EUR**	0	414.823	414.912	415.000	**...**	431.213	432.542
Working capital	EUR	0	41.482	41.491	41.500	...	43.121	43.254
Cumulative	EUR	0	41.482	41.491	41.500	...	43.121	43.254
Investment in working capital	EUR	41.482	9	9	9	...	133	
Free working capital	**EUR**					**...**		**43.254**

Table 7-42. Revenues - (Solar Panels)

Item	Unit	2030	2031	2032	...	2049	2050
Heat	**EUR**	**1.396.767**	**1.398.836**	**1.400.905**	**...**	**1.779.453**	**1.810.481**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	16.004	16.004	16.004	...	16.004	16.004
Total	**EUR**	**1.396.767**	**1.398.836**	**1.400.905**	**...**	**1.779.453**	**1.810.481**

7.3.2.1.3 Techno-economic analysis results

A detailed techno-economic assessment was carried out here to evaluate the key financial indicators, including NPV, IRR, and Payback Period. Results are provided in Table 7-43.

Table 7-43. Results of Techno-economic analysis for Solar Panels

NPV	EUR	**-3.491.774**
IRR	%	**2,51**
Payback Period	-	**16,6**

7.3.2.2 Electric Boilers

Electric boilers constitute a part of a larger investment that combines additional solutions such as solar panels, waste-to-energy systems, heat pumps, and thermal energy storage (TES). In this chapter, the individual techno-economic feasibility of electric boilers is evaluated.

7.3.2.2.1 Capital investments

Capital investment estimation in electric boilers is provided in Table 7-44.

Table 7-44. Capital investment (Electric Boilers)

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	250.000	75.000	50.000	50.000	50.000	25.000
Civil and structural works	EUR	750.000	0	0	450.000	300.000	0
Production unit	EUR	1.000.000	0	0	200.000	400.000	400.000
Dry cooling towers	EUR	0	0	0	0	0	0
Electrical connection	EUR	250.000	0	0	0	50.000	200.000
Installation and commissioning	EUR	250.000	0	0	0	50.000	200.000
Contingencies	EUR	125.000	25.000	25.000	25.000	25.000	25.000
Working capital	EUR	366.959	0	0	0	0	366.959
Total	**EUR**	**2.991.959**	**100.000**	**75.000**	**725.000**	**875.000**	**1.216.959**

7.3.2.2.2 Operating costs, depreciation, working capital, and revenues

Depreciation, operating costs, working capital and revenue estimation for electric boilers is provided in Table 7-45 to Table 7-48.

Table 7-45. Depreciation - (Electric Boilers)

Item	Rate	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	20%	EUR	250.000	100.000	100.000	...		
Civil and structural works	2%	EUR	750.000	30.000	30.000	...	30.000	30.000
Production unit	5%	EUR	1.000.000	100.000	100.000	...	100.000	
Dry cooling towers	5%	EUR	0	0	0	...	0	
Electrical connection	3,33%	EUR	250.000	16.667	16.667	...	16.667	16.667
Installation and commiss.	3,33%	EUR	250.000	16.667	16.667	...	16.667	16.667
Contingencies	5%	EUR	125.000	12.500	12.500	...	12.500	
Total		**EUR**	**2.625.000**	**275.833**	**275.833**	**...**	**175.833**	**63.333**

Table 7-46. Operating costs - (Electric Boilers)

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	366.250	366.250	366.250	366.250	**...**	366.250	366.250
Maintenance	EUR	155.000	155.000	155.000	155.000	...	155.000	155.000
Insurance	EUR	26.250	26.250	26.250	26.250	...	26.250	26.250
Labour	EUR	150.000	150.000	150.000	150.000	...	150.000	150.000
Administration	EUR	30.000	30.000	30.000	30.000	...	30.000	30.000
Utilities	EUR	5.000	5.000	5.000	5.000	...	5.000	5.000
Variable Costs	**EUR**	3.303.341	3.335.980	3.340.865	3.348.857	...	3.281.880	3.515.868
Electricity	EUR	3.295.103	3.327.661	3.332.533	3.340.506	...	3.273.696	3.507.100
Consumables	EUR	8.238	8.319	8.331	8.351	...	8.184	8.768
Total	**EUR**	**3.669.591**	**3.702.230**	**3.707.115**	**3.715.107**	**...**	**3.648.130**	**3.882.118**

Table 7-47. Working capital - (Electric Boilers)

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	**EUR**	0	3.669.591	3.702.230	3.707.115	**...**	3.648.130	3.882.118
Working capital	EUR	0	366.959	370.223	370.711	...	364.813	388.212
Cumulative	EUR	0	366.959	370.223	370.711	...	387.506	388.212
Investment in working capital	EUR	366.959	3.264	488	799	...	705	
Free working capital	**EUR**					**...**		**388.212**

Table 7-48. Revenues - (Electric Boilers)

Item	Unit	2030	2031	2032	...	2049	2050
Heat	**EUR**	**2.462.925**	**2.487.260**	**2.490.902**	**...**	**2.446.924**	**2.621.382**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	28.219	28.456	28.456	...	22.007	23.172
Total	**EUR**	**2.462.925**	**2.487.260**	**2.490.902**	**...**	**2.446.924**	**2.621.382**

7.3.2.2.3 Techno-economic analysis results

A detailed techno-economic assessment was carried out here to evaluate the key financial indicators, including NPV, IRR, and Payback Period. Results are provided in Table 7-49.

Table 7-49. Results of Techno-economic analysis for Electric Boilers

NPV	EUR	**-15.256.943**
IRR	%	-
Payback Period	-	-

7.3.2.3 Waste to Energy

Waste to energy constitute a part of a larger investment that combines additional solutions such as solar panels, electric boilers, heat pumps, and thermal energy storage (TES). In this chapter, the individual techno-economic feasibility of waste to energy is evaluated.

7.3.2.3.1 Capital investments

Capital investment estimation in waste to energy is provided in Table 7-50.

Table 7-50. Capital investment (Waste to Energy)

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	9.000.000	2.700.000	1.800.000	1.800.000	1.800.000	900.000
Civil and structural works	EUR	54.000.000	0	0	32.400.000	21.600.000	0
Production unit	EUR	95.000.000	0	0	19.000.000	38.000.000	38.000.000
Dry cooling towers	EUR	5.000.000	0	0	1.000.000	2.000.000	2.000.000
Electrical connection	EUR	2.000.000	0	0	0	400.000	1.600.000
Installation and commissioning	EUR	5.000.000	0	0	0	1.000.000	4.000.000
Contingencies	EUR	8.500.000	1.700.000	1.700.000	1.700.000	1.700.000	1.700.000
Working capital	EUR	1.314.980	0	0	0	0	1.314.980
Total	**EUR**	**179.814.980**	**4.400.000**	**3.500.000**	**55.900.000**	**66.500.000**	**49.514.980**

7.3.2.3.2 Operating costs, depreciation, working capital, and revenues

Depreciation, operating costs, working capital and revenue estimation for waste to energy is provided in Table 7-51 to

Table 7-54.

Table 7-51. Depreciation - (Waste to Energy)

Item	Rate	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	20%	EUR	9.000.000	1.800.000	1.800.000	...		
Civil and structural works	2%	EUR	54.000.000	1.080.000	1.080.000	...	1.080.000	1.080.000
Production unit	5%	EUR	95.000.000	4.750.000	4.750.000	...	4.750.000	
Dry cooling towers	5%	EUR	5.000.000	250.000	250.000	...	250.000	
Electrical connection	3,33%	EUR	2.000.000	66.667	66.667	...	66.667	66.667
Installation and commiss.	3,33%	EUR	5.000.000	166.667	166.667	...	166.667	166.667
Contingencies	5%	EUR	8.500.000	425.000	425.000	...	425.000	
Total		**EUR**	**178.500.000**	**8.538.333**	**8.538.333**	**...**	**6.738.333**	**1.313.333**

Table 7-52. Operating costs - (Waste to Energy)

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**6.699.500**	**6.699.500**	**6.699.500**	**6.699.500**	**...**	**6.699.500**	**6.699.500**
Maintenance	EUR	5.355.000	5.355.000	5.355.000	5.355.000	...	5.355.000	5.355.000
Insurance	EUR	892.500	892.500	892.500	892.500	...	892.500	892.500
Labour	EUR	360.000	360.000	360.000	360.000	...	360.000	360.000
Administration	EUR	72.000	72.000	72.000	72.000	...	72.000	72.000
Utilities	EUR	20.000	20.000	20.000	20.000	...	20.000	20.000
Variable Costs	**EUR**	**6.450.297**	**6.485.915**	**6.466.429**	**6.582.950**	**...**	**9.137.188**	**9.175.517**
Additional fuel (NG)	EUR	813.600	813.600	813.600	813.600	...	813.600	813.600
CO2 emission	EUR	1.895.638	1.913.789	1.913.142	1.959.109	...	4.041.331	4.133.584
Ash and slag disposal	EUR	3.291.038	3.306.020	3.288.541	3.350.966	...	3.644.779	3.588.180
Consumables	EUR	450.021	452.506	451.146	459.276	...	637.478	640.152
Total	**EUR**	**13.149.797**	**13.185.415**	**13.165.929**	**13.282.450**	**...**	**15.836.688**	**15.875.017**

Table 7-53. Working capital - (Waste to Energy)

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	EUR	0	13.149.797	13.185.415	13.165.929	**...**	15.836.688	15.875.017
Working capital	EUR	0	1.314.980	1.318.541	1.316.593	...	1.583.669	1.587.502
Cumulative	EUR	0	1.314.980	1.318.541	1.318.541	...	1.583.669	1.587.502
Investment in working capital	EUR	1.314.980	3.562	0	9.704	...	3.833	
Free working capital	**EUR**					**...**		**1.587.502**

Table 7-54. Revenues - (Waste to Energy)

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	**5.042.274**	**5.049.128**	**5.078.786**	**...**	**7.525.173**	**7.379.176**
Average market price	EUR/MWh	115,60	115,77	115,94	**...**	147,27	149,84
Production	MWh	43.618	43.613	43.804	**...**	51.097	49.247
Heat	**EUR**	**18.297.003**	**18.545.958**	**18.188.209**	**...**	**23.404.998**	**24.371.978**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	209.640	212.179	207.779	...	210.495	215.435
Waste treatment (incineration)	**EUR**	**19.746.229**	**19.836.121**	**19.731.247**	**...**	**21.868.674**	**21.529.083**
Gate Fee	EUR/t	60,00	60,00	60,00	...	60,00	60,00
Treatment of waste	t	329.104	330.602	328.854	...	364.478	358.818
Total	**EUR**	**43.085.506**	**43.431.207**	**42.998.241**	**...**	**52.798.845**	**53.280.236**

7.3.2.3.3 Techno-economic analysis results

A detailed techno-economic assessment was carried out here to evaluate the key financial indicators, including NPV, IRR, and Payback Period. Results are provided in Table 7-55.

Table 7-55. Results of Techno-economic analysis for Waste to Energy

NPV	EUR	**165.254.819**
IRR	%	**12,87**
Payback Period	**-**	**6,5**

7.3.2.4 Heat Pumps

Heat pumps constitute a part of a larger investment that combines additional solutions such as solar panels, electric boilers, waste to energy, and thermal energy storage (TES). In this chapter, the individual techno-economic feasibility of heat pumps is evaluated.

7.3.2.4.1 Capital investments

Capital investment estimation in heat pumps is provided in Table 7-56.

Table 7-56. Capital investment (Heat Pumps)

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	250.000	75.000	50.000	50.000	50.000	25.000
Civil and structural works	EUR	500.000	0	0	300.000	200.000	0
Production unit	EUR	2.000.000	0	0	400.000	800.000	800.000
Dry cooling towers	EUR	0	0	0	0	0	0
Electrical connection	EUR	250.000	0	0	0	50.000	200.000
Installation and commissioning	EUR	300.000	0	0	0	60.000	240.000
Contingencies	EUR	200.000	40.000	40.000	40.000	40.000	40.000
Working capital	EUR	314.212	0	0	0	0	314.212
Total	**EUR**	3.814.212	115.000	90.000	790.000	1.200.000	1.619.212

7.3.2.4.2 Operating costs, depreciation, working capital, and revenues

Depreciation, operating costs, working capital and revenue estimation for heat pumps is provided in Table 7-57 to Table 7-60.

Table 7-57. Depreciation - (Heat Pumps)

Item	Rate	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	20%	EUR	250.000	200.000	200.000	...		
Civil and structural works	2%	EUR	500.000	30.000	30.000	...	30.000	30.000
Production unit	5%	EUR	2.000.000	400.000	400.000	...	400.000	
Dry cooling towers	5%	EUR	0	0	0	...	0	
Electrical connection	3,33%	EUR	250.000	33.333	33.333	...	33.333	33.333
Installation and commiss.	3,33%	EUR	200.000	20.417	20.417	...	20.417	20.417
Contingencies	5%	EUR	200.000	30.625	30.625	...	30.625	
Total		**EUR**	**3.400.000**	**714.375**	**714.375**	**...**	**514.375**	**83.750**

Table 7-58. Operating costs - (Heat Pumps)

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**635.000**	**635.000**	**635.000**	**635.000**	**...**	**635.000**	**635.000**
Maintenance	EUR	385.000	385.000	385.000	385.000	...	385.000	385.000
Insurance	EUR	65.000	65.000	65.000	65.000	...	65.000	65.000
Labour	EUR	150.000	150.000	150.000	150.000	...	150.000	150.000
Administration	EUR	30.000	30.000	30.000	30.000	...	30.000	30.000
Utilities	EUR	5.000	5.000	5.000	5.000	...	5.000	5.000
Variable Costs	**EUR**	**2.507.116**	**2.583.687**	**2.488.305**	**2.619.577**	**...**	**3.177.217**	**3.386.506**
Electricity	EUR	2.499.617	2.575.959	2.480.862	2.611.742	...	3.167.714	3.376.377
Consumables	EUR	7.499	7.728	7.443	7.835	...	9.503	10.129
Total	**EUR**	**3.142.116**	**3.218.687**	**3.123.305**	**3.254.577**	**...**	**3.812.217**	**4.021.506**

Table 7-59. Working capital - (Heat Pumps)

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	**EUR**	0	3.142.116	3.218.687	3.123.305	**...**	3.812.217	4.021.506
Working capital	EUR	0	314.212	321.869	312.331	...	381.222	402.151
Cumulative	EUR	0	314.212	321.869	321.869	...	387.543	402.151
Investment in working capital	EUR	314.212	7.657	0	3.589	...	14.608	
Free working capital	**EUR**					**...**		**402.151**

Table 7-60. Revenues - (Heat Pumps)

Item	Unit	2030	2031	2032	...	2049	2050
Heat	**EUR**	**6.550.701**	**6.762.542**	**6.487.703**	**...**	**8.304.672**	**8.873.978**
Price	EUR/MWh	87,28	87,41	87,54	...	111,19	113,13
Production	MWh	75.056	77.368	74.114	...	74.689	78.441
Total	**EUR**	**6.550.701**	**6.762.542**	**6.487.703**	**...**	**8.304.672**	**8.873.978**

7.3.2.4.3 Techno-economic analysis results

A detailed techno-economic assessment was carried out here to evaluate the key financial indicators, including NPV, IRR, and Payback Period. Results are provided in Table 7-61.

Table 7-61. Results of Techno-economic analysis for Heat Pumps

NPV	EUR	**31.908.957**
IRR	%	**50,48**
Payback Period	-	**1,3**

7.3.2.5 WtE + Solar collectors + Heat pumps + Electric boilers + Heat storage (TES)

In this chapter, the techno-economic feasibility is evaluated as an aggregate for all the previously analysed investments, i.e., solar panels, electric boilers, waste-to-energy systems, heat pumps, and thermal energy storage (TES).

7.3.2.5.1 Capital investments

Aggregated capital investment estimation is provided in Table 7-62.

Table 7-62. Capital investment (Aggregated)

Item	Unit	Total	2025	2026	2027	2028	2029
Land acquisition	EUR	0	0	0	0	0	0
Engineering and project manag.	EUR	10.100.000	3.030.000	2.020.000	2.020.000	2.020.000	1.010.000
Civil and structural works	EUR	56.750.000	0	0	34.050.000	22.700.000	0
Production unit	EUR	111.000.000	0	0	22.200.000	44.400.000	44.400.000
Dry cooling towers	EUR	5.000.000	0	0	1.000.000	2.000.000	2.000.000
Thermal energy storage	EUR	20.400.000	0	0	4.080.000	8.160.000	8.160.000
Electrical connection	EUR	2.600.000	0	0	0	520.000	2.080.000
Installation and commissioning	EUR	6.500.000	0	0	0	1.300.000	5.200.000
Contingencies	EUR	9.635.000	1.927.000	1.927.000	1.927.000	1.927.000	1.927.000
Working capital	EUR	2.037.633	0	0	0	0	2.037.633
Total	**EUR**	**224.022.633**	**4.957.000**	**3.947.000**	**65.277.000**	**83.027.000**	**66.814.633**

7.3.2.5.2 Operating costs, depreciation, working capital, and revenues

Aggregated depreciation, operating costs, working capital and revenue estimation is provided in Table 7-63 to Table 7-66.

Table 7-63. Depreciation - (Aggregated)

Item	Rate	Unit	Base value	2030	2031	...	2049	2050
Engineering and project manag.	20%	EUR	10.100.000	2.220.000	2.220.000	...	0	0
Civil and structural works	2%	EUR	56.750.000	1.170.000	1.170.000	...	1.170.000	1.170.000
Production unit	5%	EUR	111.000.000	5.900.000	5.900.000	...	5.900.000	0
Dry cooling towers	5%	EUR	5.000.000	250.000	250.000	...	250.000	0
Thermal energy storage	5%	EUR	20.400.000	1.020.000	1.020.000		1.020.000	
Electrical connection	3,33%	EUR	2.600.000	120.000	120.000	...	120.000	120.000
Installation and commiss.	3,33%	EUR	6.450.000	237.083	237.083	...	237.083	237.083
Contingencies	5%	EUR	9.635.000	508.625	508.625	...	508.625	0
Total		**EUR**	**221.935.000**	**11.425.708**	**11.425.708**	**...**	**9.205.708**	**1.527.083**

Table 7-64. Operating costs - (Aggregated)

Item	Unit	2030	2031	2032	2033	...	2049	2050
Fixed costs	**EUR**	**8.769.750**	**8.769.750**	**8.769.750**	**8.769.750**	**...**	**8.769.750**	**8.769.750**
Maintenance	EUR	6.592.000	6.592.000	6.592.000	6.592.000	...	6.592.000	6.592.000
Insurance	EUR	1.170.750	1.170.750	1.170.750	1.170.750	...	1.170.750	1.170.750
Labour	EUR	810.000	810.000	810.000	810.000	...	810.000	810.000
Administration	EUR	162.000	162.000	162.000	162.000	...	162.000	162.000
Utilities	EUR	35.000	35.000	35.000	35.000	...	35.000	35.000
Variable Costs	**EUR**	**12.262.777**	**12.407.608**	**12.297.628**	**12.553.417**	**...**	**15.598.863**	**16.080.513**
Fuel costs	EUR	6.608.320	6.717.220	6.626.996	6.765.848	...	7.255.010	7.697.077
CO2 emission	EUR	1.895.638	1.913.789	1.913.142	1.959.109		4.041.331	4.133.584
Other costs	EUR	3.758.818	3.776.599	3.757.490	3.828.460	...	4.302.522	4.249.852

Item	Unit	2030	2031	2032	2033	...	2049	2050
Total	**EUR**	**21.032.527**	**21.177.358**	**21.067.378**	**21.323.167**	**...**	**24.368.613**	**24.850.263**

Table 7-65. Working capital - (Aggregated)

Item	Unit	2029	2030	2031	2032	...	2049	2050
OPEX	**EUR**	0	20.376.327	20.521.244	20.411.349	**...**	23.728.249	24.211.183
Working capital	EUR	0	2.037.633	2.052.124	2.041.135	...	2.372.825	2.421.118
Cumulative	EUR	0	2.037.633	2.052.124	2.052.622	...	2.401.839	2.421.118
Investment in working capital	EUR	2.037.633	14.492	497	14.101	...	19.279	0
Free working capital	**EUR**					**...**		**2.421.118**

Table 7-66. Revenues - (Aggregated)

Item	Unit	2030	2031	2032	...	2049	2050
Electricity	**EUR**	53.377.750	53.377.750	53.377.750	**...**	7.525.173	7.379.176
Heat	**EUR**	53.377.750	53.377.750	53.377.750	**...**	35.936.046	37.677.819
Other revenues (waste treatment)	**EUR**	53.377.750	53.377.750	53.377.750	**...**	21.868.674	21.529.083
Total	**EUR**	53.377.750	53.377.750	53.377.750	**...**	65.329.893	66.586.077

7.3.2.5.3 Techno-economic analysis results

A detailed techno-economic assessment was carried out here to evaluate the key financial indicators, including NPV, IRR, and Payback Period. Results are provided in Table 7-67.

Table 7-67. Results of Techno-economic analysis for Aggregated investments

NPV	EUR	**178.341.233**
IRR	%	**12,58**
Payback Period	**-**	**6,7**

7.3.3 Regulated prices of electricity and heat

7.3.3.1 General remarks

Electricity and heat produced through the cogeneration process can currently be sold at regulated prices. The calculation of these regulated prices is governed by the Methodology for Calculating, Approving, and Applying the Regulated Prices and Tariffs for Energy Production, Electrical and Thermal Services, and Thermal Energy Distribution and Supply Services, No. 396/2018 of 1.11.2019 (hereinafter: Tariff Methodology).

However, starting from 2030, it is anticipated that the Tariff Methodology will either be revised or become obsolete. This expectation primarily concerns the regulation of electricity prices rather than heat prices. Consequently, from 2030 onward, all electricity, including that produced through cogeneration, is expected to be sold at market prices. This is the primary reason why the previous techno-economic analysis, presented in the preceding chapter, was conducted using market prices.

Nonetheless, given the current regulatory framework, it remains relevant to assess the potential regulated price of electricity and heat for the most prominent CHP option, in case the Tariff Methodology remains applicable after the commissioning of the new CHP plant. Therefore, the following sections describes the calculation of the regulated prices of electricity and heat for the most viable CHP configuration i.e. CHP type-2, as well as for the gas engine-based option.

To facilitate comparison, both between the regulated prices of these options and the projected market price, the prices were adjusted to their real values (excluding the effects of inflation). However, this does not imply that, in practice, the regulated electricity prices will not be applied in their nominal values.

7.3.3.2 Methodology description

7.3.3.2.1 Purpose and Scope

The methodology for calculating, approving, and applying regulated prices and tariffs for electricity and heat production, as well as for the distribution and supply of thermal energy, is established by the Tariff Methodology. This methodology provides a standardized framework for determining regulated prices and tariffs, ensuring transparency, efficiency, and cost-effectiveness in the energy sector. It applies to all licensed entities involved in the production and distribution of electricity and thermal energy.

The methodology ensures that the approved prices and tariffs reflect justified costs, provide reasonable profitability for license holders, and promote investments in the energy sector while maintaining consumer affordability.

7.3.3.2.2 Key principles

The regulated pricing methodology is based on the following principles:

1) Cost Transparency – Prices and tariffs must reflect actual costs incurred by energy producers and distributors.
2) Non-Discriminatory Pricing – All consumers should have access to regulated tariffs without unjustified discrimination.
3) Cost Recovery & Profitability – The methodology allows energy producers to recover investment costs while ensuring a reasonable return on assets.
4) Efficiency and Economic Feasibility – Encouraging optimal use of energy resources and promoting investments in efficient technologies.
5) Investment Recovery Mechanisms – Ensuring that capital expenditures for modernizing energy infrastructure are included in the tariff structure.

7.3.3.2.3 Components of Regulated Price Calculation

Regulated price, either electricity and heat, is calculated using the following formula:

$$TP_j = \frac{(CRP_j + PE_j + R_j) + C_{cj-1}}{ELp_j}$$

whereas:

TP_j price of electricity or heat in the year j,

CRP_j regulated costs for production of electricity or heat,

PE_j exceptional losses in case of natural disasters confirmed by the competent authority,

R_j regulated profitability,

C_{cj-1} correction component of the regulated income,

ELP_j produced energy, electricity or heat.

For the purpose of this calculation, both the PE_j and the C_{cj-1}, are not taken into consideration. Therefore, regulated prices of electricity and heat was calculated based on the three variables, such as CRP_j, R_j and ELP_j. In the following chapters, both CRP_j and R_j are described in more detail, while the ELP_j, meaning the electricity and heat produced in cogeneration process, are already described in previous chapters.

7.3.3.2.3.1 Regulated costs

The total regulated costs CRP_j is calculated using the following formula:

$$CRP_j = CRE_{pj} + CAI_j + CM_{pj} + CST_{pj} + CRM_{pj} + CA_j + AC_{pj}$$

whereas:

CRP_j total regulated costs,

CRE_{pj} primary energy costs (fuel, electricity, water..),

CAI_j costs related to asset depreciation and capital recovery,

CM_{pj} material expenses (consumables and spare parts required for operation),

CST_{pj} third party services (maintenance, inspection, external service contracts…),

CRM_{pj} labour costs (salaries, social contributions…)

CA_j administrative expenses (overhead costs related to business operations)

AC_{pj} other operational expenses (regulatory fees, allowances…)

The regulated cost calculation methodology ensures that energy prices remain fair, transparent, and aligned with real operational expenses. By considering depreciation, labor costs, material consumption, and administrative expenses, the methodology provides a structured approach to pricing while promoting investment recovery and efficiency improvements.

7.3.3.2.3.2 Regulated profitability

Regulated profitability ensures that energy producers operating under the Tariff Methodology recover their investments while maintaining a fair and reasonable return on capital. Regulated profitability is calculated based on the net value of assets invested in regulated activities and the applicable rate of return. Formula for calculation of regulated profitability is as follows:

$$R_j = VNA_{nj} \cdot R_{rj}$$

whereas:

R_j regulated profitability for year j,

VNA_{nj} net value of regulated assets,

R_{rj} regulated rate of return (WACC).

Net value of regulated assets (VNA_{nj}) represents the book value of investments approved for tariff purposes, adjusted for depreciation. It is calculated as:

$$VNA_{nj} = IA_{j-1} - AA_{n-1}$$

whereas:

IA_{j-1} total investments approved by the regulatory agency until the year $j-1$,

AA_{n-1} accumulated depreciation of fixed and intangible assets until the year $j-1$.

The regulated rate of return is determined using the Weighted Average Cost of Capital (WACC) method, which accounts for both equity and debt financing. The formula for WACC is:

$$R_{rj} = \frac{R_e}{(1-t)} \cdot \frac{E}{(E+D)} + R_d \cdot \frac{D}{E+D}$$

whereas:

E equity,

D borrowed capital (debt),

R_e cost of equity,

R_d cost of debt,

t corporate income tax.

The methodology provides that the structure of the capital, used to determine the rate of return, constitutes 35% of equity and 65% of borrowed capital.

The cost of equity (R_e) is the minimum rate of return required by investors and is calculated as follows:

$$R_e = rf + rt$$

whereas:

rf risk-free rate of return (based on 10-year US government bonds according to statistical data published by BLOOMBERG),

rt country risk premium for the Republic of Moldova applied at the level of 6.75% only when, according to DAMODARAN's statistical publications, the risk rate for the Republic of Moldova will be lower than the one indicated above, the published rate will be applied.

Since cogeneration plants produce both electricity and heat, the profitability must be allocated between these two energy forms. The allocation is based on the net asset value assigned to each form of energy production.

7.3.3.2.4 Allocation Methodology of Regulated Costs on Electricity and Heat Production

The allocation of regulated costs, including the regulated profitability on assets, that cannot be precisely assigned to electricity or heat production in a cogeneration plant is a crucial aspect of tariff determination. The allocation methodology ensures that costs are fairly distributed based on the proportion of energy outputs and the efficiency of the cogeneration process.

Fuel is the most significant cost in cogeneration. The total fuel consumption for cogeneration is allocated between electricity and heat base on the Fuel Savings Method, as cogeneration is more efficient than separate production. Formula for fuel savings is as follows:

$$\Delta Q_{CETj} = \left(Q_{CTEj} + Q_{CTj}\right) - Q_{CETj}$$

whereas:

ΔQ_{CETj} fuel saved due to cogeneration efficiency,

Q_{CTEj} fuel required for separate electricity production,

Q_{CTj} fuel required for separate heat production,

Q_{CETj} total fuel consumption in cogeneration.

The fuel used for separate electricity production is determined as follows:

$$Q_{CTEj} = \frac{EE_j}{\eta_{CTE}}$$

whereas:

EE_j electricity produced,

η_{CTE} efficiency of a conventional electricity plant (default: 35%).

The fuel used for separate heat production is determined as follows:

$$Q_{CTj} = \frac{ET_j}{\eta_{CT}}$$

whereas:

ET_j heat energy produced,

η_{CT} efficiency of a conventional boiler (default: 92%).

The fuel used in cogeneration can be determined as follows:

$$Q_{CETj} = \frac{EE_j + ET_j}{\eta_{CET}}$$

whereas:

EE_j electricity produced,

ET_j heat energy produced,

η_{CET} efficiency of cogeneration plant.

The amount of fuel allocated to the electricity produced by cogeneration plant is determined according to the following formula:

$$Q_{EEj} = Q_{CTEj} - \Delta Q_{CETj} \cdot \left(\frac{Q_{CTEj}}{Q_{CTEj} + Q_{CTj}} \right)$$

The amount of fuel allocated to the heat production by cogeneration plant is determine according to the following formula:

$$Q_{ETj} = Q_{CTj} - \Delta Q_{CETj} \cdot \left(\frac{Q_{CTj}}{Q_{CTEj} + Q_{CTj}} \right)$$

The ratio of allocated fuel (electricity : heat) represents the basis for allocation of costs that are directly related to the cogeneration production and cannot be allocated directly to electricity or heat production.

7.3.3.3 Regulated price of electricity

7.3.3.3.1 CHP (type 2) [3 × SGT800 + 3 × HRSB + ST]

Calculation of fuel savings (ΔQ_{CETj}) is shown in Table 7-68.

Table 7-68. Calculation of fuel savings (ΔQ_{CETj})

Item	Unit	2030	2031	2032	...	2049	2050
Fuel for separate electricity production	**MWh**	**2.457.921**	**2.608.410**	**2.478.404**	...	**2.411.068**	**2.460.153**
Electricity production	MWh	860.272	912.943	867.441	...	843.874	861.054
Reference efficiency	%	35,0	35,0	35,0	...	35,0	35,0
Fuel for separate heat production	**MWh**	**653.008**	**701.432**	**664.949**	...	**637.807**	**667.934**
Heat production	MWh	600.768	645.317	611.753	...	586.782	614.499
Reference efficiency	%	92,0	92,0	92,0	...	92,0	92,0
Fuel for CHP (type 2)	**MWh**	**1.683.260**	**1.788.269**	**1.699.007**	...	**1.651.618**	**1.690.156**
Electricity production	MWh	860.272	912.943	867.441	...	843.874	861.054
Heat production	MWh	600.768	645.317	611.753	...	586.782	614.499
Overall efficiency	%	86,8	87,1	87,1	...	86,6	87,3
Fuel savings	**MWh**	**1.427.670**	**1.521.572**	**1.444.346**	...	**1.397.257**	**1.437.932**

The calculation of the fuel allocation ratio for electricity and heat is shown in Table 7-69.

Table 7-69. Calculation of fuel allocation ratio for electricity and heat

Item	Unit	2030	2031	2032	...	2049	2050
Fuel allocated for electricity production	**MWh**	**1.329.930**	**1.409.294**	**1.339.597**	...	**1.306.109**	**1.329.260**
Fuel for separate electricity production	MWh	2.457.921	2.608.410	2.478.404	...	2.411.068	2.460.153
Fuel for separate heat production	MWh	653.008	701.432	664.949	...	637.807	667.934
Fuel savings	MWh	1.427.670	1.521.572	1.444.346	...	1.397.257	1.437.932
Fuel allocated for heat production	**MWh**	**353.329**	**378.975**	**359.410**	...	**345.509**	**360.895**

Item	Unit	2030	2031	2032	...	2049	2050
Fuel for separate electricity production	MWh	2.457.921	2.608.410	2.478.404	...	2.411.068	2.460.153
Fuel for separate heat production	MWh	653.008	701.432	664.949	...	637.807	667.934
Fuel savings	MWh	1.427.670	1.521.572	1.444.346	...	1.397.257	1.437.932
Fuel allocation					...		
Electricity production	%	79,0	78,8	78,8	...	79,1	78,6
Heat production	%	21,0	21,2	21,2	...	20,9	21,4

Calculation of regulated costs for electricity production is shown in Table 7-70.

Table 7-70. Calculation of regulated costs for electricity production

Item	Unit	2030	2031	2032	...	2049	2050
Primary energy resources	EUR	78.013.038	82.790.875	78.812.837	...	97.606.780	101.069.043
Depreciation of fixed and intangible assets	EUR	10.774.981	10.748.164	10.753.245	...	6.894.819	6.858.466
Material expenses	EUR	390.065	413.954	394.064	...	488.034	505.345
Services provided by third parties	EUR	6.456.940	6.440.471	6.443.592	...	6.462.772	6.427.355
Labor expenses	EUR	568.866	567.415	567.690	...	569.380	566.260
Other expenses	EUR	105.387	105.118	105.169	...	105.482	104.904
Total regulated costs	EUR	96.309.278	101.065.999	97.076.598	...	112.127.267	115.531.374

Calculation of regulated profitability (R_j) for electricity production is shown in Table 7-71.

Table 7-71. Regulated profitability (R_j) calculation

Item	Unit	2030	2031	2032	...	2049	2050
Asset value	EUR	234.203.918	222.872.876	212.224.993	...	60.023.390	59.080.610
Rate of return on investment	%	6,2	6,2	6,2	...	6,2	6,2
Regulated profitability	EUR	14.499.352	13.797.857	13.138.656	...	3.715.994	3.657.627

Calculation of regulated price of electricity (TP_j) is shown in Table 7-72.

Table 7-72. Calculation of regulated price of electricity (TP_j)

Item	Unit	2030	2031	2032	...	2049	2050
Regulated income	EUR	110.808.629	114.863.856	110.215.254	...	115.843.261	119.189.000
Regulated costs	EUR	96.309.278	101.065.999	97.076.598	...	112.127.267	115.531.374
Regulated profitability	EUR	14.499.352	13.797.857	13.138.656	...	3.715.994	3.657.627
Electricity production	MWh	860.272	912.943	867.441	...	843.874	861.054
Regulated price	EUR/MWh	128,81	125,82	127,06	...	137,28	138,42

7.3.3.3.2 CHP (type 5) [Gas engines Jenbacher J920 Flextra + TES]

Calculation of fuel savings (ΔQ_{CETj}) is shown in Table 7-73.

Table 7-73. Calculation of fuel savings (ΔQ_{CETj})

Item	Unit	2030	2031	2032	...	2049	2050
Fuel for separate electricity production	**MWh**	**1.886.023**	**2.017.947**	**1.915.354**	...	**1.839.540**	**1.910.395**
Electricity production	MWh	660.108	706.282	670.374	...	643.839	668.638

Item	Unit	2030	2031	2032	...	2049	2050
Reference efficiency	%	35,0	35,0	35,0	...	35,0	35,0
Fuel for separate heat production	**MWh**	**690.632**	**738.935**	**701.376**	...	**673.580**	**699.587**
Heat production	MWh	635.382	679.820	645.266	...	619.694	643.620
Reference efficiency	%	92,0	92,0	92,0	...	92,0	92,0
Fuel for CHP (type 5)	**MWh**	**1.428.263**	**1.529.870**	**1.451.746**	...	**1.392.801**	**1.450.006**
Electricity production	MWh	660.108	706.282	670.374	...	643.839	668.638
Heat production	MWh	635.382	679.820	645.266	...	619.694	643.620
Overall efficiency	%	90,7	90,6	90,6	...	90,7	90,5
Fuel savings	**MWh**	**1.148.393**	**1.227.012**	**1.164.984**	...	**1.120.320**	**1.159.975**

The calculation of the fuel allocation ratio for electricity and heat is shown in Table 7-74.

Table 7-74. Calculation of fuel allocation ratio for electricity and heat

Item	Unit	2030	2031	2032	...	2049	2050
Fuel allocated for electricity production	**MWh**	**1.045.439**	**1.119.815**	**1.045.439**	...	**1.019.495**	**1.061.343**
Fuel for separate electricity production	MWh	1.886.023	2.017.947	1.886.023	...	1.839.540	1.910.395
Fuel for separate heat production	MWh	690.632	738.935	690.632	...	673.580	699.587
Fuel savings	MWh	1.148.393	1.227.012	1.148.393	...	1.120.320	1.159.975
Fuel allocated for heat production	**MWh**	**382.824**	**410.055**	**382.824**	...	**373.306**	**388.664**
Fuel for separate electricity production	MWh	1.886.023	2.017.947	1.886.023	...	1.839.540	1.910.395
Fuel for separate heat production	MWh	690.632	738.935	690.632	...	673.580	699.587
Fuel savings	MWh	1.148.393	1.227.012	1.148.393	...	1.120.320	1.159.975
Fuel allocation					...		
Electricity production	%	73,2	73,2	73,2	...	73,2	73,2
Heat production	%	26,8	26,8	26,8	...	26,8	26,8

Calculation of regulated costs for electricity production is shown in Table 7-75.

Table 7-75. Calculation of regulated costs for electricity production

Item	Unit	2030	2031	2032	...	2049	2050
Primary energy resources	EUR	60.426.391	64.821.140	61.601.736	...	75.071.522	79.515.801
Depreciation of fixed and intangible assets	EUR	7.436.516	7.436.533	7.436.507	...	5.258.217	5.258.101
Material expenses	EUR	604.264	648.211	616.017	...	750.715	795.158
Services provided by third parties	EUR	8.632.205	8.632.225	8.632.194	...	8.632.311	8.632.108
Labor expenses	EUR	527.015	527.016	527.015	...	527.022	527.009
Other expenses	EUR	86.284	86.284	86.284	...	86.285	86.283
Total regulated costs	EUR	77.712.676	82.151.409	78.899.753	...	90.326.073	94.814.460

Calculation of regulated profitability (R_j) for electricity production is shown in Table 7-76.

Table 7-76. Regulated profitability (R_j) calculation

Item	Unit	2030	2031	2032	...	2049	2050
Asset value	EUR	159.566.882	152.130.698	144.693.669	...	35.055.308	34.089.177
Rate of return on investment	%	6,2	6,2	6,2	...	6,2	6,2
Regulated profitability	EUR	9.878.641	9.418.273	8.957.854	...	2.170.242	2.110.430

Calculation of regulated price of electricity (TP_j) is shown in Table 7-77.

Table 7-77. Calculation of regulated price of electricity (TP_j)

Item	Unit	2030	2031	2032	...	2049	2050
Regulated income	**EUR**	**87.591.316**	**91.569.682**	**87.591.316**	**...**	**92.496.315**	**96.924.890**
Regulated costs	EUR	77.712.676	82.151.409	77.712.676	...	90.326.073	94.814.460
Regulated profitability	EUR	9.878.641	9.418.273	9.878.641	...	2.170.242	2.110.430
Electricity production	**MWh**	**660.108**	**706.282**	**660.108**	**...**	**643.839**	**668.638**
Regulated price	**EUR/MWh**	**132,69**	**129,65**	**132,69**	**...**	**143,66**	**144,96**

7.3.3.3.3 Comparison of electricity prices

Comparison of regulated prices of electricity between the CHP option 2 and 5, and between the project market electricity prices is shown in Figure 7-5.

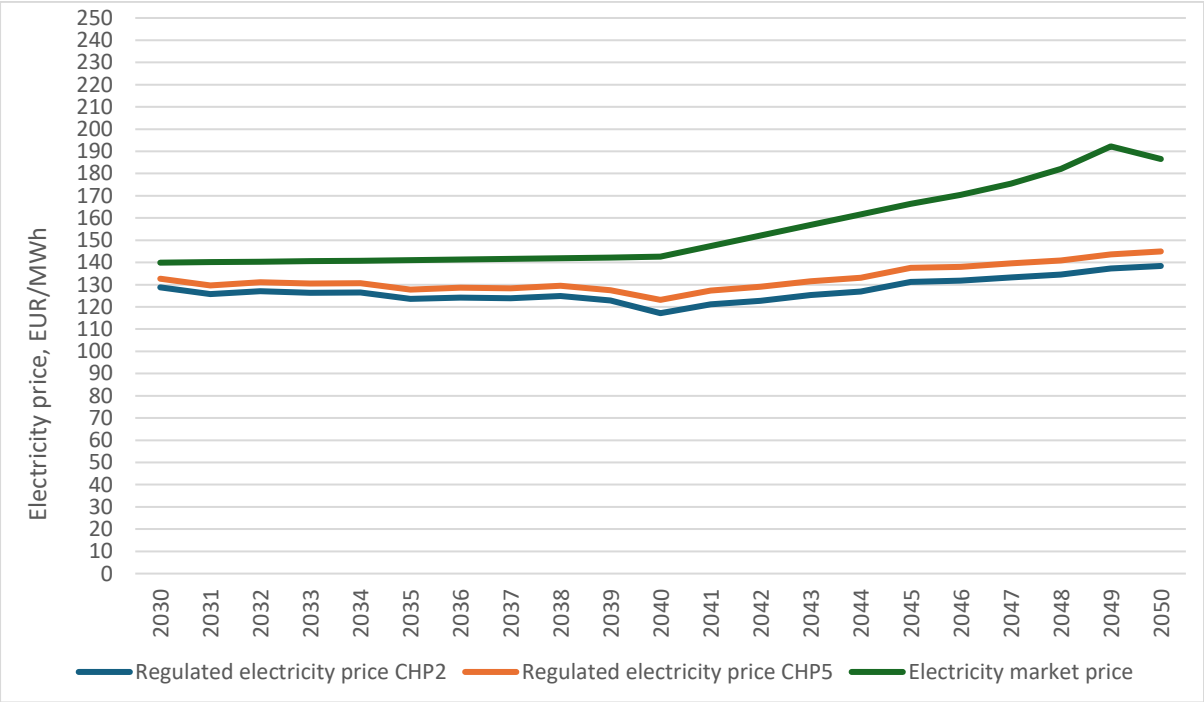


Figure 7-5. Electricity prices comparison

7.3.3.4 Regulated price of heat

7.3.3.4.1 CHP (type 2) [3 × SGT800 + 3 × HRSB + ST]

Calculation of fuel savings and allocation of fuel for heat production is shown in Table 7-68 and Table 7-69.

Calculation of regulated costs for heat production is shown in Table 7-78.

Table 7-78. Calculation of regulated costs for heat production

Item	Unit	2030	2031	2032	...	2049	2050
Primary energy resources	EUR	20.726.115	22.263.424	21.145.250	...	25.820.207	27.440.343
Depreciation of fixed and intangible assets	EUR	3.813.188	3.840.004	3.834.923	...	2.774.750	1.791.102

Item	Unit	2030	2031	2032	...	2049	2050
Material expenses	EUR	103.631	111.317	105.726	...	129.101	137.202
Services provided by third parties	EUR	1.715.448	1.731.917	1.728.796	...	1.709.616	1.745.033
Labor expenses	EUR	151.134	152.585	152.310	...	150.620	153.740
Other expenses	EUR	27.999	28.268	28.217	...	27.904	28.482
Total regulated costs	EUR	26.537.514	28.127.514	26.995.223	...	30.612.197	31.295.902

Calculation of regulated profitability (R_j) for electricity production is shown in Table 7-79.

Table 7-79. Regulated profitability (R_j) calculation

Item	Unit	2030	2031	2032	...	2049	2050
Asset value	EUR	82.883.082	79.625.955	75.685.669	...	24.155.807	15.429.019
Rate of return on investment	%	6,2	6,2	6,2	...	6,2	6,2
Regulated profitability	EUR	5.131.216	4.929.570	4.685.631	...	1.495.464	955.197

Calculation of regulated price of electricity (TP_j) is shown in Table 7-80.

Table 7-80. Calculation of regulated price of heat (TP_j)

Item	Unit	2030	2031	2032	...	2049	2050
Regulated income	**EUR**	**31.668.730**	**33.057.085**	**31.680.853**	**...**	**32.107.661**	**32.251.098**
Regulated costs	EUR	26.537.514	28.127.514	26.995.223	...	30.612.197	31.295.902
Regulated profitability	EUR	5.131.216	4.929.570	4.685.631	...	1.495.464	955.197
Heat production	**MWh**	**600.768**	**645.317**	**611.753**	**...**	**586.782**	**614.499**
Regulated price	**EUR/MWh**	**52,71**	**51,23**	**51,79**	**...**	**54,72**	**52,48**

7.3.3.4.2 CHP (type 5) [Gas engines Jenbacher J920 Flextra + TES]

Calculation of fuel savings and allocation of fuel for heat production is shown in Table 7-73 and Table 7-74.

Calculation of regulated costs for heat production is shown in Table 7-81.

Table 7-81. Calculation of regulated costs for heat production

Item	Unit	2030	2031	2032	...	2049	2050
Primary energy resources	EUR	22.127.207	23.736.295	22.557.709	...	27.488.773	29.118.675
Depreciation of fixed and intangible assets	EUR	3.639.454	3.639.438	3.639.464	...	2.841.712	1.821.829
Material expenses	EUR	221.272	237.363	225.577	...	274.888	291.187
Services provided by third parties	EUR	3.160.980	3.160.960	3.160.991	...	3.160.874	3.161.077
Labor expenses	EUR	192.985	192.984	192.985	...	192.978	192.991
Other expenses	EUR	31.596	31.596	31.596	...	31.595	31.597
Total regulated costs	EUR	29.373.494	30.998.635	29.808.322	...	33.990.820	34.617.356

Calculation of regulated profitability (R_j) for electricity production is shown in Table 7-82.

Table 7-82. Regulated profitability (R_j) calculation

Item	Unit	2030	2031	2032	...	2049	2050
Asset value	EUR	78.092.532	74.452.745	70.813.803	...	18.945.031	11.811.232
Rate of return on investment	%	6,2	6,2	6,2	...	6,2	6,2
Regulated profitability	EUR	4.834.638	4.609.302	4.384.018	...	1.172.870	731.223

Calculation of regulated price of heat (TP_j) is shown in Table 7-83.

Table 7-83. Calculation of regulated price of heat (TP_j)

Item	Unit	2030	2031	2032	...	2049	2050
Regulated income	**EUR**	**34.208.132**	**35.607.937**	**34.192.340**	**...**	**35.163.690**	**35.348.578**
Regulated costs	EUR	29.373.494	30.998.635	29.808.322	...	33.990.820	34.617.356
Regulated profitability	EUR	4.834.638	4.609.302	4.384.018	...	1.172.870	731.223
Heat production	**MWh**	**635.382**	**679.820**	**645.266**	**...**	**619.694**	**643.620**
Regulated price	**EUR/MWh**	**53,84**	**52,38**	**52,99**	**...**	**56,74**	**54,92**

7.3.3.4.3 Comparison of heat prices

Comparison of regulated prices of heat between the CHP option 2 and 5, and between the project market heat prices is shown in Figure 7-6.



Figure 7-6. Heat prices comparison

8. Sensitivity analysis

8.1 Introduction to Sensitivity Analysis

Sensitivity analysis is a crucial step in assessing the economic feasibility of complex energy infrastructure projects like a Combined Heat and Power (CHP) plant. By evaluating how variations in key parameters—Capital Expenditure (CAPEX), Operational Expenditure (OPEX, excluding fuel), and the electricity-to-natural gas (EL/NG) price ratio—impact the project's Net Present Value (NPV), this analysis enables project stakeholders to identify the primary drivers of profitability and risk.

For CHP plants, the EL/NG price ratio is particularly significant as it encapsulates not only electricity sale revenues and natural gas prices but also the costs associated with CO_2 emissions allowances. Given the increasing importance of carbon pricing in energy markets, this parameter is a critical determinant of the plant's economic performance.

This chapter presents the results of sensitivity analyses performed on multiple CHP configurations and evaluates their robustness under varying conditions. The findings provide essential insights for selecting the optimal configuration that balances profitability, operational flexibility, and market adaptability.

8.2 Methodology and Scope of Analysis

The analysis focused on three primary parameters:

- CAPEX: Variations of ±10% were modeled to account for potential cost overruns or optimizations during the design and construction phases.
- OPEX (excluding fuel): Operational costs were varied by ±10%, reflecting potential efficiencies or unforeseen expenses during plant operations.
- EL/NG Price Ratio (including CO_2 emissions costs): This parameter reflects the interplay between electricity sale revenues and the combined cost of natural gas and CO_2 emissions allowances. Historical EL/NG price ratios from 2013 to 2024 were analysed to establish realistic ranges for this parameter.

Each CHP configuration was evaluated under two distinct operational regimes:

- Minimal electrical production: This scenario prioritizes thermal energy supply while minimizing electricity output during periods of low demand.
- Maximal electrical production: This scenario maximizes electricity generation to capitalize on peak demand or favourable pricing conditions.

The sensitivity analysis revealed the varying impact of the three parameters on NPV:

- A 10% decrease in CAPEX led to a moderate NPV improvement of 7–8% across all configurations, underscoring the importance of controlling capital costs during project planning.
- A 10% reduction in OPEX resulted in a smaller NPV improvement of 3–4%, highlighting the role of operational efficiencies in sustaining profitability over the plant's lifetime.
- A 10% increase in the EL/NG price ratio (including CO_2 costs) produced a dramatic NPV improvement of over 90%. This underscores its outsized influence as the primary driver of economic outcomes, given that electricity revenues typically account for the majority of income while natural gas and CO_2 costs represent substantial expenditures.

The inclusion of CO_2 emissions costs within the EL/NG price ratio highlights the growing impact of carbon pricing policies on the economic viability of CHP plants. Favourable movements in electricity prices, natural gas costs, or CO_2 pricing can significantly enhance the plant's profitability, while adverse changes could erode financial returns.

Table 8-1. Impat on NPV results with change of parameters

Influence parameter	change	Impact on NPV		
		CHP type 1	CHP type 2	CHP type 3
CAPEX	-10%	7.8%	7.2%	7.2%
OPEX (no fuel)	-10%	3.7%	3.4%	3.3%
EL/NG Price ratio	10%	92.1%	95.0%	93.4%

8.3 Results of sensitivity analysis

A statistical analysis of historical EL/NG price ratios (2013–2024) revealed that most values cluster between 1.6 and 2.2, accounting for over 70% of occurrences. Ratios below 1.2 or above 2.8 are considered outliers and represent extreme scenarios that stress operational flexibility and economic robustness. This insight was pivotal in designing sensitivity scenarios that reflect realistic market conditions.

Table 8-2. Statistial analysis of historical average monthly price ratios electrcity/(natural gas + CO2)

Ratio of electricity/(natural gas + CO2 prices)		No.	Share
0.01	1.00	0	0.00%
1.00	1.19	1	0.69%
1.20	1.39	8	5.56%
1.40	1.59	12	8.33%
1.60	1.79	23	15.97%
1.80	1.99	30	20.83%
2.00	2.19	22	15.28%
2.20	2.39	16	11.11%
2.40	2.59	10	6.94%
2.60	2.79	10	6.94%
2.80	2.99	4	2.78%
3.00	100.00	8	5.56%
Weighted average		**2,06**	

Table 8-3. Results of sensitivity analysis for minimal electrcity production mode

EL/NG price ratio		Minimal electrical production				
		CHP type 1	CHP type 2	CHP type 3	CHP type 4	CHP type 5
1	NPV	-224.091.185	-309.546.427	-517.669.074	-294.685.827	-216.254.350
	IRR, %	-9,9	-9,4	-8,9	#NUM!	-8,0
	LCOH factor	2,3	2,3	2,5	2,3	2,1
1,2	NPV	-145.096.935	-198.356.475	-358.756.727	-223.128.278	-129.501.365
	IRR, %	-2,9	-2,6	-3,2	-8,5	-1,5
	LCOH factor	2,1	2,0	2,2	2,1	1,8
1,4	NPV	-69.245.187	-92.081.198	-204.556.815	-151.578.286	-48.276.018

EL/NG price ratio		Minimal electrical production				
		CHP type 1	CHP type 2	CHP type 3	CHP type 4	CHP type 5
	IRR, %	1,6	1,8	0,7	-2,8	2,8
	LCOH factor	1,8	1,77	1,95	1,92	1,64
1,6	NPV	542.067	5.880.855	-62.285.397	-82.743.570	28.422.122
	IRR, %	5,0	5,2	3,8	1,1	6,2
	LCOH factor	1,5	1,5	1,6	1,7	1,4
1,8	NPV	70.075.661	103.753.804	77.555.566	-18.916.788	105.120.263
	IRR, %	7,9	8,1	6,4	4,2	9,1
	LCOH factor	1,2	1,2	1,3	1,6	1,2
2	NPV	139.609.255	201.626.754	217.396.529	44.053.002	181.818.403
	IRR, %	10,5	10,7	8,8	6,8	11,7
	LCOH factor	1,0	0,9	1,0	1,4	1,0
2,2	NPV	209.142.849	299.499.703	357.237.493	107.022.791	258.516.543
	IRR, %	12,9	13,1	10,9	9,1	14,2
	LCOH factor	0,7	0,7	0,7	1,2	0,8
2,4	NPV	278.676.442	397.372.652	497.078.456	169.992.580	335.214.684
	IRR, %	15,1	15,3	13,0	11,3	16,4
	LCOH factor	0,4	0,4	0,4	1,0	0,6
2,6	NPV	348.210.036	495.245.601	636.919.420	232.962.370	411.912.824
	IRR, %	17,2	17,4	14,9	13,3	18,6
	LCOH factor	0,1	0,1	0,1	0,8	0,4
2,8	NPV	417.743.630	593.118.550	776.760.383	295.932.159	488.610.964
	IRR, %	19,2	19,4	16,7	15,2	20,7
	LCOH factor	-0,2	-0,2	-0,2	0,7	0,2
3	NPV	487.277.224	690.991.500	916.601.346	358.901.949	565.309.104
	IRR, %	21,1	21,3	18,4	17,0	22,6
	LCOH factor	-0,4	-0,5	-0,5	0,5	0,0

Table 8-4. Resulst of sensisity analysis for maximum electricity production mode

EL/NG price ratio		Maximum electrical production				
		CHP type 1	CHP type 2	CHP type 3	CHP type 4	CHP type 5
1	NPV	-675.788.204	-1.049.813.282	-1.721.098.880	-982.382.827	-932.483.852
	IRR, %	-	-	-	-	-
	LCOH factor	3,9	4,2	4,5	4,0	3,8
1,2	NPV	-500.098.771	-779.141.279	-1.277.212.202	-814.825.772	-725.176.350
	IRR, %	-	-	-	-	-
	LCOH factor	3,3	3,5	4,0	3,6	3,3
1,4	NPV	-324.409.338	-508.469.276	-833.325.524	-647.268.716	-517.868.849
	IRR, %	-	-	-	-	-
	LCOH factor	2,7	2,83	3,15	3,17	2,78
1,6	NPV	-148.777.860	-237.797.272	-389.438.846	-479.711.661	-310.561.348

EL/NG price ratio		Maximum electrical production				
		CHP type 1	CHP type 2	CHP type 3	CHP type 4	CHP type 5
	IRR, %	-2,8	-4,1	-3,6	-	-
	LCOH factor	2,1	2,2	2,3	2,7	2,3
1,8	NPV	12.358.680	12.716.526	20.125.277	-312.154.605	-104.911.222
	IRR, %	5,5	5,4	5,4	-	0,2
	LCOH factor	1,5	1,5	1,5	2,3	1,8
2	NPV	166.963.846	250.905.532	410.740.543	-144.901.949	79.469.532
	IRR, %	11,3	11,7	11,5	-1,9	8,0
	LCOH factor	0,8	0,8	0,6	1,9	1,3
2,2	NPV	321.569.011	489.094.539	801.355.809	8.070.725	261.900.133
	IRR, %	16,1	16,8	16,5	5,3	13,9
	LCOH factor	0,2	0,1	-0,2	1,5	0,8
2,4	NPV	476.174.177	727.283.546	1.191.971.074	155.519.059	444.330.734
	IRR, %	20,4	21,4	21,0	10,6	19,0
	LCOH factor	-0,4	-0,6	-1,1	1,1	0,3
2,6	NPV	630.779.343	965.472.552	1.582.586.340	302.967.394	626.761.335
	IRR, %	24,4	25,6	25,2	15,1	23,5
	LCOH factor	-1,0	-1,2	-1,5	0,6	-0,2
2,8	NPV	785.384.508	1.203.661.559	1.973.201.605	450.415.728	809.191.936
	IRR, %	28,0	29,5	29,0	19,1	27,7
	LCOH factor	-1,5	-1,5	-1,5	0,2	-0,7
3	NPV	939.989.674	1.441.850.566	2.363.816.871	597.864.062	991.622.538
	IRR, %	31,5	33,2	32,6	22,7	31,6
	LCOH factor	-1,5	-1,5	-1,5	-0,2	-1,2

Table 8-5. Statistial analysis of results of SA for minimal electrical production

Ranking	Minimal electrical production			
	CHP type 1	CHP type 2	CHP type 3	CHP type 5
1st place	0	6	7	20
2nd place	8	23	1	1
Last place	7	0	19	5

Table 8-6. Statistial analysis of results of SA for maximal electrical production

Ranking	Maximal electrical production			
	CHP type 1	CHP type 2	CHP type 3	CHP type 5
1st place	11	7	13	2
2nd place	2	17	8	4
Last place	0	0	11	22

Table 8-7. Statistial analysis of results of SA for total

Ranking	Minimal electrical production			
	CHP type 1	CHP type 2	CHP type 3	CHP type 5
1st place	11	13	20	22
2nd place	10	40	9	5
Last place	7	0	30	27

Minimal Electrical Production:

- At an EL/NG ratio of 2.0, NPV ranged from €140 million (CHP Type 1) to €217 million (CHP Type 3), with Internal Rate of Return (IRR) values between 10.5 % and 11.7 %.
- CHP Type 3 achieved the highest economic performance but exhibited higher risk due to its single-block design, which reduces operational flexibility.

Maximal Electrical Production:

- At an EL/NG ratio of 2.0, CHP Type 3 delivered the highest NPV (€411 million) and second highest IRR (11.5 %), followed by CHP Type 2 with highest IRR (11.7 %) and second highest NPV (€251 million).
- These results highlight the ability of larger configurations to capitalize on electricity market opportunities, though operational risks remain a consideration.

By evaluating each configuration across these regimes, the analysis accounts for the seasonal and market fluctuations typical of district heating systems integrated with electricity markets.

CHP Type 3 and Type 5: These configurations exhibit significant volatility, achieving as many first-place rankings as last-place ones. While they perform exceptionally well under favorable conditions, their economic outcomes are highly sensitive to changes in the EL/NG price ratio, making them less reliable in uncertain market environments.

CHP Type 2: Dominates the second-place rankings across scenarios, demonstrating its consistent performance and low volatility. This suggests that it provides a balanced compromise between high profitability and operational risk.

9. Selection of optimum variant of CHP

The decision to select the optimal CHP configuration requires a balanced evaluation of technical capabilities, economic performance, operational flexibility, and risk resilience. The sensitivity analysis and key performance indicators (KPIs) highlight distinct strengths and weaknesses across the configurations. While CHP Type 3 and CHP type 5 deliver good performance in certain metrics, CHP Type 2 emerges as the most robust and adaptable option for the specific needs of the system. Below is a detailed evaluation leading to the final recommendation.

9.1 Comparative Performance of CHP Configurations

Following tables give summary of most important technical and financial parameters of each CHP type.

Table 9-1. Basic technical parameters

Variant		Basic configuration	Maximum electrical output	Maximum thermal output	Maximum Efficiency (CHP)	Maximum Electrical efficiency (cond)	Technical minimum - MECL (electrical)
			MW	MW	%	%	MW
A	CHP type 1	2 x SGT800 + 2 x HRSB + ST	164	120	87.6	54.3	44.0
B	CHP type 2	3 x SGT800 + 3 x HRSB + ST	246	180	87.6	54.3	44.0
C	CHP type 3	1 x 9F04 + 1 x HRSB + ST	440	260	89.1	57.3	202
D	CHP type 4	3 x GT LM6000 + 3 x HRB	162	174	85.0	40.8	~0 (House Load)
E	CHP type 5	18 x Gas engines Jenbacher J920	191	185	91.0	46.5	~0 (House Load)

Table 9-2. Mass and Energy Balance

Variant		Mode of operation	Annual heat production	Share in total heat demand	Annual heat production of old units**	Share of existing units in heat demand	Annual electrical production	Fuel consumption
			MWh		MWh		MWh	MWh
A	CHP type 1	Max electricity	420,638	24.63%	641.914	37.58%	1,371,122	2,634,196
		Min electricity	420,638	24.63%	641.914	37.58%	597,947	1,173,844
B	CHP type 2	Max electricity	600,768	35.17%	461.784	27.04%	2,112,271	4,042,624
		Min electricity	600,768	35.17%	461.784	27.04%	860,272	1,683,260
C	CHP type 3	Max electricity	833,215	48.78%	229.337	13.43%	3,478,777	6,313,571
		Min electricity	833,215	48.78%	229.337	13.43%	1,322,150	2,441,186

Variant		Mode of operation	Annual heat production	Share in total heat demand	Annual heat production of old units**	Share of existing units in heat demand	Annual electrical production	Fuel consumption
			MWh		MWh		MWh	MWh
D	CHP type 4	Max electricity	599,494	35.10%	463.057	27.11%	1,312,942	3,216,230
		Min electricity	599,494	35.10%	463.057	27.11%	549,850	1,412,107
E	CHP type 5	Max electricity	635,382	37.20%	427.170	25.01%	1,594,535	3,447,497
		Min electricity	635,382	37.20%	427.170	25.01%	660,108	1,428,263

Table 9-3. Efficincy and electrical market share

Variant		Mode of operation	Total efficiency (annual average)	Electrical efficiency (annual average)	Domestic electric market	Export of Electricity
					%	MWh
A	CHP type 1	Max electricity	68.02%	51.31%	100%	0
		Min electricity	86.77%	50.20%	100%	0
B	CHP type 2	Max electricity	67.11%	51.51%	100%	0
		Min electricity	86.80%	50.36%	100%	280
C	CHP type 3	Max electricity	68.30%	54.09%	97.80%	78.000
		Min electricity	88.29%	53.15%	100%	0
D	CHP type 4	Max electricity	59.46%	40.08%	100%	0
		Min electricity	81.39%	38.19%	100%	0
E	CHP type 5	Max electricity	64.68%	46.25%	100%	0
		Min electricity	90.70%	46.22%	100%	0

Table 9-4. Results of economical anaylsis

Variant		CAPEX	Specific CAPEX	NPV	IRR		LCOH factor (NPV=0)
		Million EUR	MEUR/MW	EUR	%		x fuel price
A	CHP type 1	241.2	1.47	139,609,255	10.5		0.95
				166,963,846	11.3		0.84
B	CHP type 2	341.8	1.38	201,626,754	10.7		0.94
				250,905,532	11.7		0.80
C	CHP type 3	583.4	1.33	217,396,529	8.8		1.04
				410,740,543	11.5		0.62
D	CHP type 4	258.9	1.60	44,053,002	6.8		1.39
				-144,901,949	-1.9		1.94
E	CHP type 5	259.0	1.36	181,818,403	11.7		1.02
				79,469,532	8.0		1.30

The following results summarize the performance of the analysed CHP variants across key metrics:

- Maximum thermal output: CHP Type 3 achieves the highest thermal output capacity (260 MW), making it technically suitable for meeting peak district heating demand.
- Maximum electrical output: CHP Type 3 also excels in electrical output, providing up to 440 MW, the highest among the configurations.
- Maximum overall efficiency: CHP Type 5 leads with a total efficiency of 91%, driven by its compact gas engine technology.
- Maximum electrical efficiency: CHP Type 3 achieves the highest electrical efficiency of 57.3%, optimizing electricity production during peak periods.
- Operational flexibility: CHP Type 5 stands out with the greatest flexibility due to its modular design, enabling partial shutdowns during low demand while maintaining system reliability.
- Lowest CAPEX: CHP Type 1 offers the lowest capital expenditure, making it attractive from an investment perspective.
- Lowest specific CAPEX (€/MW): CHP Type 3 minimizes specific investment costs relative to its capacity, enhancing its financial efficiency in large-scale applications.
- Highest NPV: CHP Type 3 demonstrates the strongest economic returns, with the highest NPV across scenarios.
- Highest IRR; CHP Type 2 and CHP Type achieves highest IRR in analysed scenarios
- Lowest Levelized Cost of Heat (LCOH): CHP Type 3 and CHP Type 2 achieve the most competitive LCOH, further enhancing its economic attractiveness.
- Lowest sensitivity to market changes: CHP Type 2 exhibits the least sensitivity to variations in critical economic parameters, ensuring stable performance under fluctuating market conditions.

Although CHP Type 3 excels in many metrics, several limitations make it less suitable for the given application:

- Single-block configuration: The design of CHP Type 3 relies on a single large unit, which introduces operational risks. Any failure or maintenance requirement would result in a complete shutdown, compromising the reliability of both electricity and heat supply.
- Oversized capacity: The high thermal and electrical output of CHP Type 3 is mismatched with the district heating system's demand profile. This leads to inefficiencies during periods of lower demand, making it less adaptable to dynamic system requirements.
- High volatility: CHP Type 3's economic performance is highly sensitive to variations in the electricity-to-natural gas (EL/NG) price ratio, increasing financial risk in volatile market conditions.

Due to afore mentioned reasons, detail comparison will be made for CHP type 2 and CHP type 5 as technically and economically best options for future new CHP unit.

9.2 Comparison of CHP type 2 and CHP type 5

CHP Type 2 consists of three SGT800 gas turbines, three heat recovery steam boilers (HRSB), and a steam turbine, while CHP Type 5 is based on 18 gas engines (Jenbacher J920 FleXtra). While CHP Type 5 achieves the highest overall efficiency (91.0%), its electrical efficiency remains lower than that of CHP Type 2, which is a key factor in electricity market revenue potential. CHP Type 2's combined cycle configuration ensures higher electrical efficiency, making it better suited for balancing heat and electricity production.

One of the primary considerations in selecting a CHP configuration is its flexibility in operation.

- CHP Type 2 offers good operational flexibility due to its modular gas turbine design, allowing for partial shutdowns during periods of lower demand while maintaining system reliability.

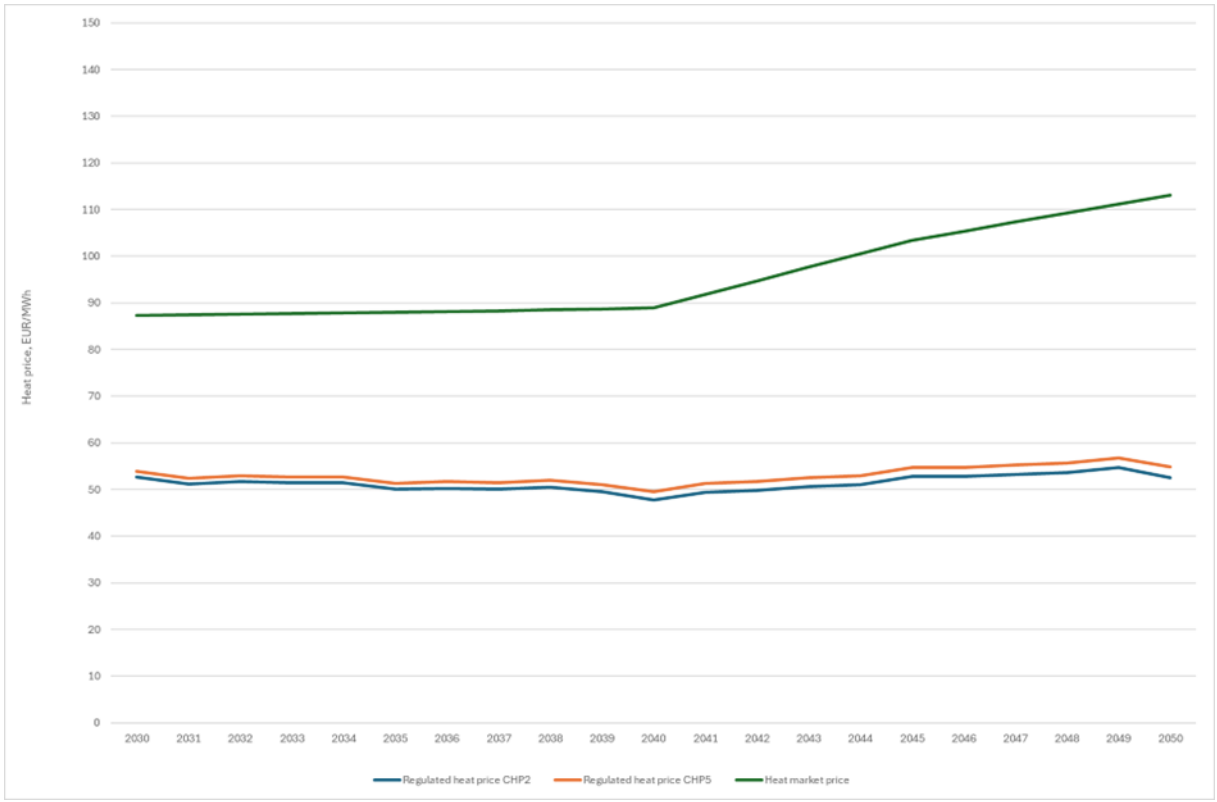
- CHP Type 5 provides even higher redundancy with multiple engines, allowing independent operation of units. With a minimum operational load of practically 0 MWe (rapid start-up from cold start), CHP Type 5 offers greater flexibility than CHP Type 2, making it more adaptable to fluctuating demand and enabling more efficient low-load operation.

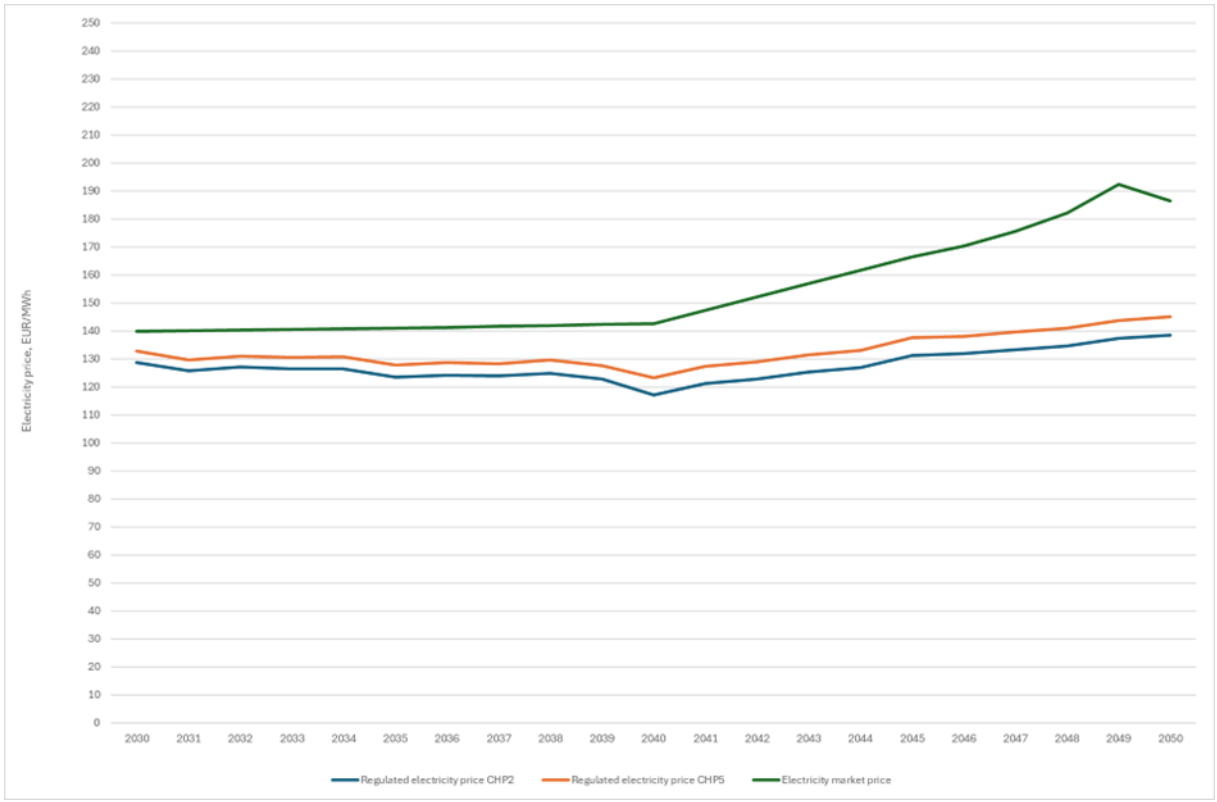
Given the increasing integration of renewable energy sources into Moldova's electricity system, flexibility and fast response to grid fluctuations are crucial. CHP Type 5 offers superior modularity and lower minimum load, making it highly responsive to changes in energy demand.

The economic and financial evaluation of CHP Type 2 and CHP Type 5 reveals distinct differences in cost-effectiveness, investment viability, and long-term operational sustainability (see table xx). CHP Type 2 demonstrates a higher Net Present Value (NPV) in both maximum and minimum electricity production modes, indicating a stronger return on investment under most market conditions. While CHP Type 5 has a higher Internal Rate of Return (IRR), its Levelized Cost of Heat (LCOH) is significantly higher than that of CHP Type 2, making heat production more expensive.

In minimum electricity production mode, CHP Type 2 achieves an NPV of 201,6 million EUR, which is higher than the 181,8 million EUR recorded for CHP Type 5. However, in maximum electricity production mode, the NPV values become more diverse, with CHP Type 2 at 250,9 million EUR and CHP Type 5 lower at 79,5 million EUR. The IRR values follow a similar trend, however in minimum production mode with CHP Type 5 slightly outperforming CHP Type 2 (11,7 % compared to 10,7 %). This due to lower CAPEX for CHP Type 5 and better overall efficiency, which is backed up by higher current heat prices, used in basic scenario. For maximum production of electricity CHP type 2 give higher IRR, due to favourable electricity prices set in basic scenario (see chapter 7.3).

LCOH analysis highlights a crucial advantage of CHP Type 2, as its lower cost of heat production makes it more favourable in a district heating system where affordability is key. The use of LCOH factors derived from the study confirms that CHP Type 2 remains the more economically viable choice in the long run, particularly when operating at higher electricity output levels. Additionally, the impact of regulated heat and electricity prices further strengthens the case for CHP Type 2. Its lower regulated tariffs make it a more attractive option for both electricity and heat production, ensuring long-term economic sustainability (see picture below). Conversely, CHP Type 5, while more flexible in operation, faces higher regulated tariffs, reducing its competitive advantage in a price-sensitive market.





Overall, the financial analysis confirms that CHP Type 2 provides a more stable and cost-effective solution, particularly for large-scale district heating applications. Its combination of higher NPV,

lower LCOH, and resilience to market fluctuations makes it the preferred choice for long-term investment and operational efficiency.

The sensitivity analysis conducted for CHP Type 2 and CHP Type 5 evaluates their economic resilience under varying electricity-to-gas price (EL/NG) ratios. The results indicate significant variations in financial performance based on market conditions.

- CHP Type 5 outperforms at low EL/NG ratios: When the EL/NG ratio is below 1.4, CHP Type 5 demonstrates a higher Internal Rate of Return (IRR) and better economic viability. Its modular gas engine configuration allows for more efficient adaptation to lower electricity revenues. This is primarily due to its higher overall efficiency and lower electricity-to-heat ratio, which means that when electricity prices are lower, its profitability remains stable due to the favorable heat price component.
- CHP Type 2 gains advantage as EL/NG increases: When the EL/NG ratio exceeds 1.6, CHP Type 2 becomes the more favorable option due to its higher electrical efficiency, allowing for increased revenue generation in high electricity price scenarios. The key advantage in this scenario is that with more electricity output for the same thermal output, CHP Type 2 benefits more significantly from rising electricity prices compared to CHP Type 5.
- Price resilience and risk factors: CHP Type 2 shows greater resilience to electricity price fluctuations, making it a more stable long-term investment under projected market conditions. In contrast, CHP Type 5, despite its operational flexibility, remains more sensitive to price shifts, particularly in high-gas-price scenarios, since its revenue stream is more dependent on heat prices rather than electricity prices.

The overall results suggest that while CHP Type 5 is advantageous in periods of low electricity prices due to its higher operational flexibility and stronger heat price support, CHP Type 2 provides stronger economic security in the long run by leveraging its superior electrical efficiency and cost-effectiveness in a rising EL/NG price environment.

9.3 Selection of optimum variant

CHP Type 2 strikes a balance between performance, reliability, and risk mitigation. Its ability to operate efficiently across a wide range of EL/NG price ratios makes it resilient to market uncertainties, while its modularity and alignment with thermal demand reduce operational risks. Additionally, its robust design ensures that it can continue supplying heat and electricity even during turbine outages or maintenance.

While CHP Type 5 offers high overall efficiency and operational flexibility, its lower electrical efficiency and higher reliance on heat revenues make it more sensitive to variations in electricity prices. In scenarios where heat prices remain favorable, CHP Type 5 delivers competitive returns due to its high thermal efficiency and lower electricity-to-heat ratio. However, in situations where electricity prices increase, CHP Type 2 outperforms due to its superior electrical efficiency, enabling higher electricity revenues for the same thermal output.

This dynamic makes CHP Type 2 the more balanced option, providing a stable economic return across a broader range of market conditions. Its ability to generate a larger share of electricity revenue mitigates risk in volatile energy markets, ensuring long-term financial viability and a sustainable energy supply.

Based on the comprehensive analysis, CHP Type 2 is recommended as the optimal solution for the proposed CHP plant. Its modular design, economic stability, alignment with system demand, and low sensitivity to market volatility ensure a reliable and sustainable energy

solution. This balanced approach supports long-term economic and operational success, positioning CHP Type 2 as the most suitable choice for the district heating system.

9.4 Alternative Gas Turbine Configurations for CHP Type 2

While the previous evaluation of CHP Type 2 was based on a configuration of three Siemens SGT-800 gas turbines, an alternative approach using two larger gas turbines with similar combined cycle efficiency can also be considered. This alternative ensures that competition exists not only between EPC contractors but also among gas turbine manufacturers, which is a crucial factor in optimizing project cost and technical performance.

To demonstrate this, a comparison is made between the **GE 6F.03** and the **Ansaldo AE64.3A**, both of which offer electrical outputs in the range of 80 MW per unit and can be paired with a steam turbine to match the required capacity.

Table 9-5. Impat on NPV results with change of parameters

Technical charateristic	Unit	CHP type 2 alternative configurations		
		Siemens SGT-800	GE 6F.03	Ansaldo AE64.3A
Number of gas turbines	---	3	2	2
Electrical output of one (1) gas turbine in simply cycle (ISO conditions)	MW	62.5	88.0	78.0
Net heat rate (simple cycle)	kJ/kWh	8.759	9.788	9.984
Net efficiency (simple cycle)	%	41.1	36.8	36.4
Total electrical output (combine cycle)	MW	245	240	220
Total thermal output (combine cycle)	MW	180	185	170

The table demonstrates that using two **larger** gas turbines instead of three smaller ones can achieve **comparable electrical and thermal output** while increasing competition between gas turbine manufacturers. Both the GE 6F.03 and Ansaldo AE64.3A configurations maintain efficiency levels competitive with the Siemens SGT-800, ensuring high fuel utilization and strong financial returns.

By considering these alternatives, the procurement strategy for CHP Type 2 is no longer limited to Siemens as the primary gas turbine supplier. Instead, it allows competition between major OEMs such as **GE, Siemens and Ansaldo**, increasing the likelihood of securing better pricing and technical service agreements. This approach enhances flexibility in equipment selection and ensures the most economically advantageous configuration for the CHP plant.

10. Investment Plan for DHS Development in Chisinau

10.1 Introduction

The investment plan for the District Heating System (DHS) in Chisinau provides a phased roadmap for implementing key projects that will modernize the system, improve energy efficiency, and transition towards renewable and sustainable heat sources. The plan is structured into four phases spanning short-term (2025-2027), medium-term (2027-2035), and long-term (beyond 2035) goals. It integrates technical, legal, and infrastructure considerations for each technology to ensure feasibility and alignment with Moldova's national energy strategy. Summary of the investment plan is given in the table below. Total CAPEX estimation for Phases 1 & 2 exceeds 445 MEUR, with CHP type 2 and WtE plant as capitally most intensive projects.

Table 10-1. Summary of the investment plan for DHS Chisinau

Phase	Investment	Description	Prerequisites	Infrastructure Needs	Estimated CAPEX, million EUR
Phase 1 (2025 – 2027)	Thermal Energy Storage (TES)	Installation of a 1,200 MWh TES system	Energy efficiency laws, EIA	DHS pipeline integration, land at CHP Source 1	20,4
Phase 2 (2027 – 2030)	CHP Type 2 (Critical Priority)	Construction of a 246 MWe, 180 MWt CHP unit	Permits, natural gas supply contracts	Heat and electricity connections, gas infrastructure	321,42
	Reserve fuel storage for CHP Type 2	Reserve fuel (Diesel) storage for two weeks operation	As part of CHP Type 2 project		5,0
	Heat Pump (20 MWt)	Installation near wastewater plant	Electricity market, water permits, in cooperation of wastewater company	Heat pipelines, wastewater infrastructure	3,8
	Waste-to-Energy Plant (20 MWe)	RDF-based plant generating 20 MWe/54 MWt	Waste management system, RDF supply	Waste centers, RDF logistics	179,8
	Solar Thermal Field (14 MWt)	Solar field with HVFPC collectors	Renewable incentives, land permits	Pipeline connections, TES integration	17,0
	Electric Boiler (40 MWt)	Peak load electric boiler installation	Power exchange, grid connection	TES and DHS pipeline integration	3,0
Phase 3 (2030 – 2035)	Preparatory Activities for CHP Source 1	Feasibility studies for RES-based CHP	Hydrogen/biogas strategies, RES regulations	Infrastructure for hydrogen/biogas	N/A
Phase 4 (beyond 2035)	Modernize CHP Source 1 (Hydrogen/Biogas)	Replacement of boilers, construction of RES CHP	Hydrogen/biogas infrastructure	Advanced fuel pipelines and storage facilities	N/A
	Expand Renewable Systems	Additional solar fields, heat	Feasibility studies, geothermal permits	Land, heat storage systems	NA/

		pumps, storage			

10.2 Phase 1: Short Term (2025-2027)

In the short term, the focus is on establishing the foundational infrastructure to enhance system flexibility and prepare for future production units. The implementation of a Thermal Energy Storage (TES) system will be a critical step. The TES system is designed to store up to 1,200 MWh of thermal energy, with a charging and discharging power of 125 MW. This system, measuring 41 meters in height and 22 meters in diameter, will be located adjacent to CHP Source 1, ensuring seamless integration with existing infrastructure.

During this phase, detailed design studies will be conducted to finalize the technical configuration of the TES. Procurement of components and subsequent construction will follow, ensuring that the system aligns with national energy efficiency laws and environmental standards. Integration with existing DHS pipelines and the allocation of space within the CHP Source 1 site will be key infrastructural requirements.

10.3 Phase 2: Short to Medium Term (2027-2030)

The short to medium term is centered on modernizing the DHS with the implementation of critical and complementary projects. The most significant investment in this phase is the construction of CHP Type 2, a high-efficiency combined heat and power unit designed to replace outdated infrastructure. CHP Type 2 will have an electrical capacity of 245 MWe and a thermal capacity of 180 MWt, consisting of three SGT800 gas turbines, heat recovery steam boilers (HRSBs), and a steam turbine. This new unit will serve as the backbone of the DHS and will be located at CHP Source 1.

To implement CHP Type 2, the design and funding processes will be prioritized, followed by construction and commissioning. Legal prerequisites include obtaining construction permits and ensuring compliance with EU and national emission regulations. High-capacity natural gas infrastructure and upgraded heat and electricity grid connections will be required to support this investment.

The second priority in this phase is the installation of a 20 MWt heat pump near the central wastewater treatment plant. This heat pump will utilize R1234ze as a working fluid and operate with a Coefficient of Performance (COP) of 3.4, extracting heat from wastewater to supply the DHS. This project will require compliance with F-Gas regulations and permits for water extraction and discharge. Heat exchanger infrastructure and heat transmission pipelines will be essential for integrating the heat pump with the DHS. The heat pump's high efficiency and renewable energy utilization place it immediately after CHP Type 2 in importance.

The construction of a Waste-to-Energy (WtE) plant is the third priority in this phase. Designed to process 200,000 tons per year of Refuse-Derived Fuel (RDF) with a lower heating value of 12 MJ/kg, the WtE plant will generate 20 MWe of electricity and 54 MWt of heat. The proposed site for the plant is near a waste storage facility approximately 10 km from urban areas. The project's success depends on the establishment of a national waste management system, the construction of waste collection and sorting centers, and the integration of RDF supply chains.

The fourth priority is the implementation of a Solar Thermal Field. This field, covering 4 hectares near CHP Source 1, will have a thermal capacity of 14 MWt. High-Vacuum Flat Plate Collectors (HVFPC) will be used to capture solar energy, which will be integrated into the DHS through TES and heat pipelines. The project will require land-use permits, alignment with renewable energy incentives, and the installation of monitoring systems for optimal operation. While essential for renewable heat production, its lower energy output compared to other technologies places it fourth in priority.

Finally, the installation of a 40 MWt electric boiler will complete this phase. This boiler will provide peak load management and enhance operational flexibility. Operating at an efficiency of 99% and pressures of up to 16 bar, the electric boiler will require a high-voltage grid connection for electricity supply. The boiler will be integrated into the existing DHS pipelines, ensuring efficient distribution of heat. Its role as a backup and peak-load management system places it as the fifth priority in Phase 2.

Phase 2 Priority List:

1. CHP Type 2: This unit is critical for modernizing the DHS and providing a high-efficiency, high-capacity backbone for heat and electricity generation.
2. Heat Pump: Utilizing renewable heat from wastewater, the heat pump significantly enhances efficiency and aligns with sustainability goals.
3. Waste-to-Energy Plant: While impactful, the success of this project depends on external factors such as the establishment of a national waste management system.
4. Solar Thermal Field: A key renewable energy project that complements TES but delivers lower energy outputs compared to other investments.
5. Electric Boiler: Provides essential peak load flexibility but serves as a supporting system rather than a primary heat source.

10.4 Phase 3: Medium Term (2030-2035)

The medium term will focus on preparatory activities for advanced modernization projects and expanding renewable heat production. During this phase, feasibility studies will be conducted to evaluate the potential for transitioning CHP Source 1 to hydrogen and biogas-compatible systems or building new CHP biomass power plant. These studies will assess the technical and financial requirements for replacing natural gas boilers and developing additional renewable energy-based CHP units.

Simultaneously, detailed planning will begin for implementing seasonal heat storage systems and expanding renewable heat production capacities. These preparatory activities will lay the groundwork for the full realization of advanced modernization projects in the subsequent phase.

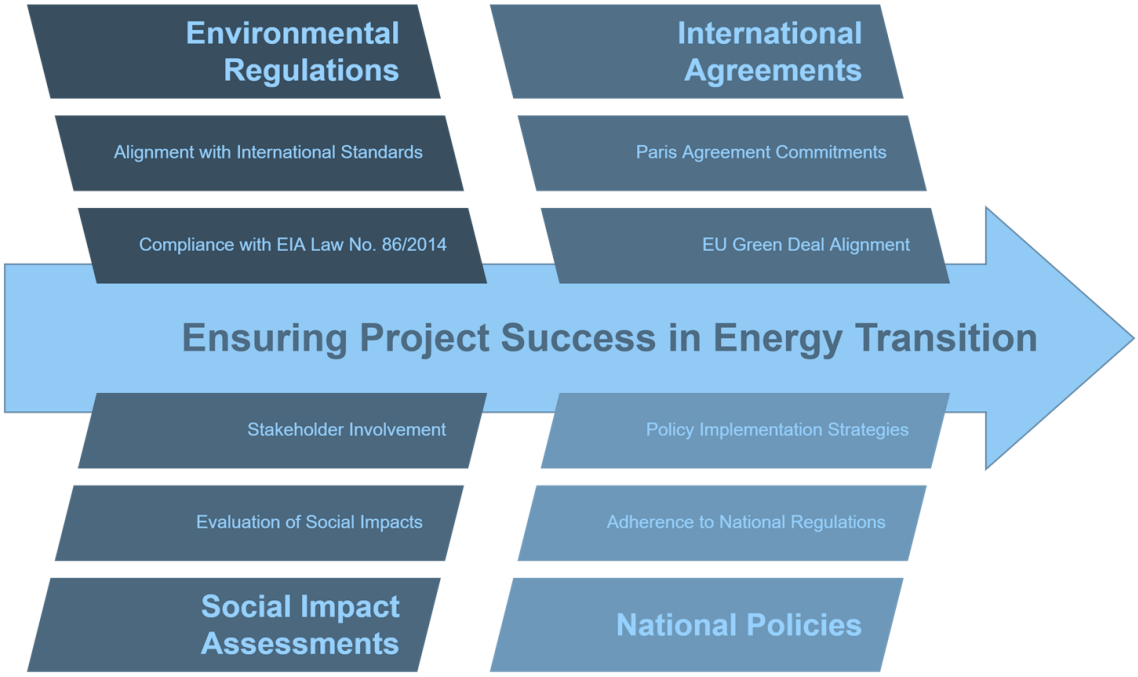
10.5 Phase 4: Long Term (Beyond 2035)

The long-term phase will focus on implementing the modernization of CHP Source 1 and expanding renewable energy systems to achieve a low-carbon DHS. Natural gas boilers will be replaced with hydrogen and biogas-compatible units, and new RES-based CHP units will be constructed. These investments will rely on the development of hydrogen and biogas production, transportation infrastructure, and advanced fuel pipelines.

The expansion of renewable energy systems will include the installation of additional solar thermal fields and heat pumps, as well as the implementation of seasonal heat storage solutions. These projects will enhance the overall sustainability and flexibility of the DHS, ensuring its long-term reliability and alignment with national and EU decarbonization goals.

11. Environmental and Social Assessment

The **District Heating Efficiency Improvement Project (DHEIP2)** in Chisinau, Moldova, is a key initiative aimed at modernizing the district heating system to improve energy efficiency, reduce greenhouse gas emissions, and enhance service reliability. The project expands on earlier initiatives, notably the first phase of the DHEIP, which tackled infrastructure and service reliability issues. The present Feasibility Study, carried out within DHEIP2, focuses on identification and assessment of investments for future project(s) for integrating high-efficiency technologies, including cogeneration, waste-to-energy processes, solar and other renewable energy sources, to further optimize performance while ensuring environmental sustainability.



Environmental and social factors play an important role in the project's success. Moldova has committed to aligning its energy policies with international sustainability frameworks, including the Paris Agreement[35] and the EU Green Deal[36], reinforcing its objective of transitioning toward a low-carbon economy. The project is developing in accordance with

Moldova's national environmental regulations, as well as international standards set forth by the World Bank's Environmental and Social Framework. Key regulatory requirements include compliance with the Environmental Impact Assessment Law No. 86/2014, which mandates the evaluation of environmental and social impacts at all stages of project development.

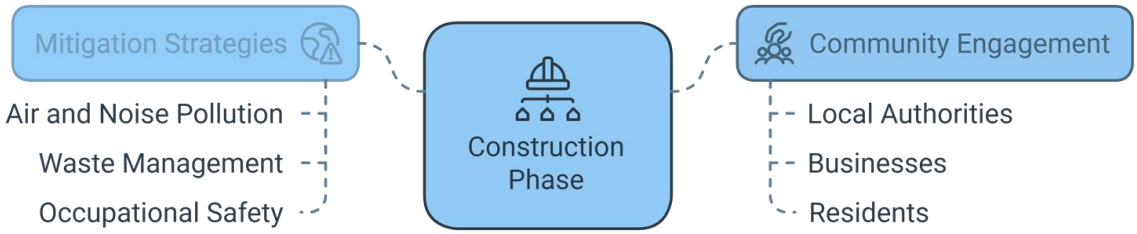
[35] https://unfccc.int/process-and-meetings/the-paris-agreement
[36] https://commission.europa.eu/strategy-and-policy/priorities-2019-2024/european-green-deal_en

The project will introduce model of the environmental and social risk management strategies to minimize adverse impacts during both construction and operational phases.

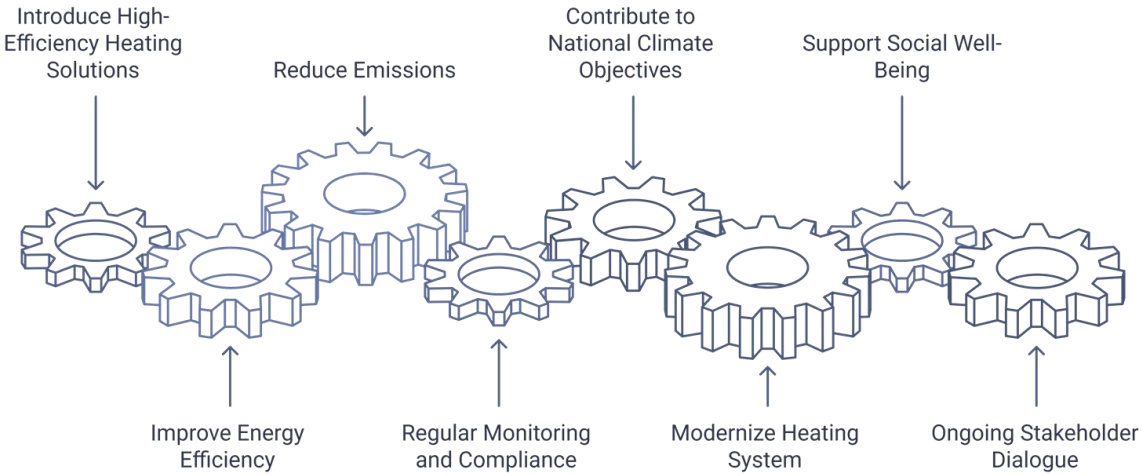


The design phase includes suggestions regarding assessments for establishing climate resilience measures and ensuring the project aligns with Moldova's commitments to environmental sustainability.

The construction phase involves the implementation of mitigation strategies to address air and noise pollution, waste management, and occupational safety risks. Managing emissions and pollution control remains a priority, particularly given the introduction of new technologies such as cogeneration and waste-to-energy units, which require close monitoring of their environmental footprint. Additionally, community engagement plays a crucial role, ensuring transparency in project execution and fostering cooperation among stakeholders, including local authorities, businesses, and residents.



The operational phase of the project focuses on achieving long-term sustainability goals by improving energy efficiency and reducing emissions. The introduction of high-efficiency heating solutions aims to enhance the overall performance of the district heating system while minimizing its environmental impact. Regular monitoring and compliance measures will be implemented to ensure that emissions remain within acceptable limits and that the project continues to contribute to Moldova's national climate objectives. The modernization efforts will also support social well-being by providing a more reliable and efficient heating service for residents, public institutions, and businesses in Chisinau. Ongoing dialogue with stakeholders will ensure that concerns are addressed and that best practices in environmental and social governance are maintained.

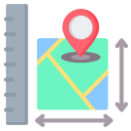


By integrating advanced technologies and adhering to stringent environmental and social regulations, the project will represent a strategic investment in Moldova's sustainable development. The project's approach emphasizes energy efficiency, environmental responsibility, and long-term economic benefits, reinforcing its role as a critical step toward modernizing the district heating infrastructure while aligning with national and international sustainability objectives.

11.1 Environmental and Social Assessment



As part of the Environmental and Social Assessment (ESA) for the project, several key environmental and social impacts have been identified. One of the primary environmental concerns relates to emissions of pollutants into the atmosphere, particularly from the operation of the proposed Waste-to-Energy (WtE) plant and solar power station. Ensuring compliance with national air quality standards and international best practices in emission control will be essential for mitigating potential environmental risks.



Additionally, the project involves the acquisition or transfer of industrial land for the development of these energy facilities. This process requires a structured approach to land acquisition that aligns with national legislation and international safeguards, ensuring that any land transactions are conducted transparently and equitably, minimizing disruption to local communities and industrial stakeholders.



On the social side, stakeholder engagement and public consultation will play a crucial role in the project's implementation. Effective communication with affected communities, local authorities, and other interested parties will be necessary to address concerns, provide project-related information, and ensure inclusive decision-making processes. The development of a robust Stakeholder Engagement Plan (SEP) will help facilitate continuous dialogue between project developers and key stakeholders.

Furthermore, the project necessitates the revision and enhancement of JSC Termoelectrica internal policies and operational frameworks. This includes updates to occupational health and safety (OHS) protocols to ensure worker protection during both construction and operational phases, as well as improvements to the company's Environmental and Social Management System (ESMS) to align with best industry practices and regulatory requirements. Strengthening these internal mechanisms will contribute to the long-term sustainability and compliance of the project.

The ESA also identifies several applicable Environmental and Social Standards (ESS) of the World Bank Group (WBG) that are triggered by the proposed activities:

- **ESS1 – Assessment and Management of Environmental and Social Risks and Impacts:** Requires a systematic approach to assessing and mitigating environmental and social risks, ensuring the integration of comprehensive impact management measures into project planning.
- **ESS2 – Labour and Working Conditions:** Ensures the protection of workers' rights, safe and healthy working conditions, and fair labour practices, particularly for those involved in the construction and operation of the new energy facilities.
- **ESS3 – Resource Efficiency and Pollution Prevention:** Emphasizes the need to minimize emissions, optimize energy and water use, and ensure sustainable waste management, particularly in relation to the WtE plant and sludge treatment.
- **ESS4 – Community Health and Safety:** Addresses potential impacts on surrounding communities, including air quality, traffic disruptions, and exposure to hazardous materials, ensuring robust measures to protect public health and safety.
- **ESS10 – Stakeholder Engagement and Information Disclosure:** Requires inclusive and ongoing engagement with local communities, authorities, and other relevant stakeholders to ensure transparency, participation, and access to project-related information.



Overall, the ESA highlights the need for comprehensive planning and implementation of mitigation measures to address these environmental and social impacts effectively during the design stage, construction and operational phases. By integrating best practices in emission control, land management, stakeholder engagement, and corporate governance, the project aims to enhance its environmental sustainability and social acceptance, ensuring alignment with both national and international environmental and social standards.

11.2 Overview of the proposed Alternative scenario for the Project

The Project proposed several solutions to achieve the district's energy goals for heating and electricity production. Additionally, the project suggested upgrading existing infrastructure to improve energy efficiency, incorporating smart grid technology to optimize energy distribution, and promoting community awareness programs to encourage energy-saving practices. By adopting these measures, the district aims to not only meet its current energy needs sustainably but also pave the way for a greener future with reduced carbon emissions and enhanced energy security.

Combined Heat and Power (CHP) Systems



CHP production units form the backbone of the proposed energy solutions, ensuring a stable and efficient heat and power supply. The study considers different CHP configurations, including gas turbines, heat recovery steam boilers, and steam turbines. These systems significantly reduce energy losses by utilizing waste heat for district heating. The main advantage of CHP is its high efficiency in fuel conversion, which results in lower operating costs and emissions.

Waste-to-Energy (WtE) Plants



WtE plants convert municipal and industrial waste into usable energy. The analysis evaluates various thermal treatment methods such as combustion on grates, rotary kilns, and fluidized beds. This alternative reduces landfill waste while generating electricity and heat, making it an environmentally sustainable option. However, the choice of technology depends on waste composition and calorific value. Additionally, WtE plants can significantly cut greenhouse gas emissions when properly managed.

Solar Collectors



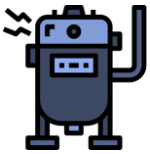
Solar district heating is a renewable solution that utilizes solar thermal energy for heating. Large solar collector fields can be integrated into district heating systems to provide supplementary energy, reducing dependency on fossil fuels. While still a developing market, solar heating systems are increasingly being adopted in colder climates, where they contribute to sustainable urban energy planning.

Heat Pumps



Heat pumps use low-temperature heat sources such as wastewater, groundwater, or ambient air to provide heating. This alternative is highly energy-efficient, especially when combined with geothermal or district heating systems. The system operates using an environmentally friendly refrigerant (R1234ze) and offers a high coefficient of performance (COP) of 3.4. However, its efficiency depends on the temperature gradient between the heat source and the heating network.

Electric Boilers



Electric boilers provide additional flexibility by allowing heat generation during periods of low electricity prices. They are especially useful for balancing intermittent renewable energy sources like solar and wind. While they do not produce direct emissions, their sustainability depends on the energy mix of the grid. In the analyzed scenarios, electric boilers serve as a complementary technology to enhance system adaptability.

Thermal Energy Storage (TES)



TES systems store excess heat for later use, improving energy efficiency by balancing supply and demand fluctuations. These systems enable better integration of intermittent renewable energy sources. In the proposed scenarios, TES is implemented as a water-based storage system to optimize heat distribution within district heating networks.

The emission calculations were conducted in accordance with GHG Protocol accounting, covering both Scope 1 and Scope 2 emissions. The assessment includes the projected emissions for the standard operational phase, during which the CHP system functions using natural gas, as well as for emergency and start-up modes, where the unavailability of natural gas necessitates the use of electric boilers powered by grid electricity for heat production. Additionally, a worst-case scenario was analysed, considering the simultaneous operation of all equipment at maximum emission capacity.

The emission indicators of the GHG Protocol[37] "emission factors from Cross-sector Tools" (March 2024) are used. The source of emission indicators for greenhouse gases (CO_2, CH_4, N_2O) is the 2006 IPCC Guidelines for National Greenhouse Gas Inventory, Volume 2[38], which is used to calculate stationary sources of emissions of pollutants, such as CHP and WtE. Harmonized Grid Emission factor data set IFI TWG[39] (July 2018) is used for the calculations of the grid emissions.

The following table provides a **comparative analysis** of the proposed scenarios based on **energy performance calculations and emissions modelling**, detailing the respective pollutant emission levels under each operational condition.

Parameters	**Project scenarios**				
	Variant A	**Variant B**	**Variant C**	**Variant D**	**Variant E**
CHP System	2 x SGT800 + 2 x HRSB + ST	3 x SGT800 + 3 x HRSB + ST	1 x 9F04 + 1 x HRSB + ST	3 x GT LM6000 + 3 x HRB	18 x Gas engines Jenbacher J920
Maximum electrical output (MW)	164	246	440	162	191
Maximum thermal output (MW)	120	180	260	174	185
Waste-to-Energy (WtE)	1 × Bubbling Fluidized Bed WtE (54 MWt, 19.75 MWe)	1 × Bubbling Fluidized Bed WtE (54 MWt, 19.75 MWe)	1 × Bubbling Fluidized Bed WtE (54 MWt, 19.75 MWe)	1 × Bubbling Fluidized Bed WtE (54 MWt, 19.75 MWe)	1 × Bubbling Fluidized Bed WtE (54 MWt, 19.75 MWe)
Solar Collectors	14 MWt	14 MWt	14 MWt	14 MWt	14 MWt
Geothermal Heat Pumps	1 × 20 MWt two-stage R1234ze	1 × 20 MWt two-stage R1234ze	1 × 20 MWt two-stage R1234ze	1 × 20 MWt two-stage R1234ze	1 × 20 MWt two-stage R1234ze
Electric Boilers	1×40 MWt electric hot boiler	1×40 MWt electric hot boiler	1×40 MWt electric hot boiler	1×40 MWt electric hot boiler	1×40 MWt electric hot boiler
Thermal Energy Storage (TES)	Yes	Yes	Yes	Yes	Yes
Flexibility & Redundancy	Moderate	High	Moderate (Single Turbine)	High (Multiple Units)	Very High (Modular Design)
Reliability	High	Very High	Moderate (One Gas Turbine)	High	Very High
Efficiency	High	Very High	Very High	High	Very High
Total CO_2eq emissions, tonnes	1,547,377	1,638,242	1,778,963	1,522,775	1,769,023

[37] Calculation Tools and guidance | GHG Protocol
[38] Publications - IPCC-TFI
[39] Harmonized Grid Emission factor data set | UNFCCC

Parameters	Project scenarios				
	Variant A	**Variant B**	**Variant C**	**Variant D**	**Variant E**
Without grid emissions CO_2eq emissions, tonnes	535,201	565,558	612,696	526,981.9	609,250
Fossil Fuel Dependence	Moderate	Moderate	High	Moderate	Moderate
Suitability for Variable Demand	Good	Very Good	Very Good	Excellent	Excellent

All emission variations stem from the CHP facility configuration and the equipment used for electricity and heat production, where emissions scale proportionally with energy output and fuel consumption.

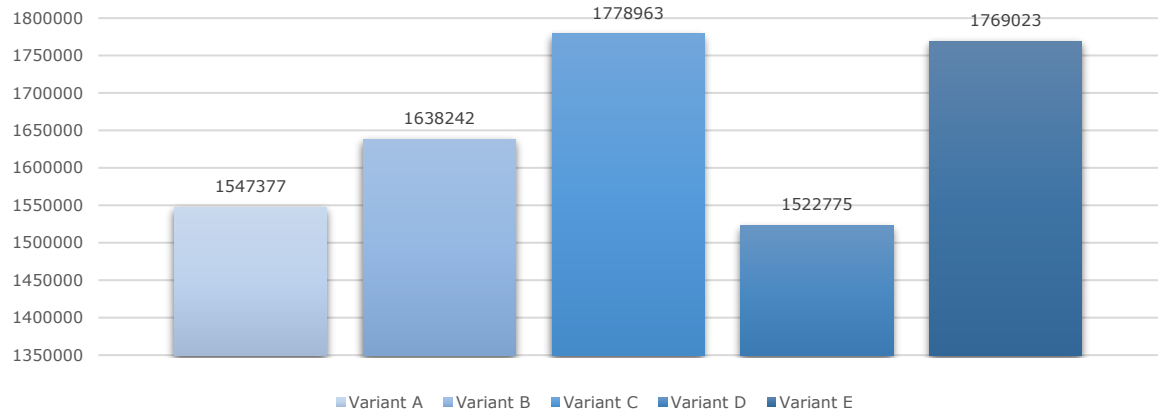


Figure 11-1. Annual total emissions CO2eq, tonnes

Among the evaluated CHP options, **CHP Type 2** provides the optimal balance between performance, reliability, and risk mitigation. Its modular design allows it to efficiently adapt to fluctuations in electricity and natural gas price ratios, reducing exposure to market uncertainties. Additionally, its alignment with thermal demand minimizes operational risks, while its robust structure ensures uninterrupted heat and electricity supply, even during turbine outages or maintenance periods.

While **CHP Type 3** offers the highest financial returns under ideal conditions, its rigid operational framework and high **sensitivity to market fluctuations** make it a less viable choice. Conversely, **CHP Type 5**, despite its cost-effectiveness and efficiency, **lacks the adaptability and capacity** needed to meet the district heating system's evolving demands.

Based on a comprehensive assessment, **CHP Type 2 is recommended** as the optimal solution for the proposed CHP plant. Its economic stability, resilience to market volatility, and alignment with system requirements make it the most suitable and sustainable choice. This balanced approach supports long-term economic viability and operational efficiency, ensuring reliable district heating while maintaining environmental and financial sustainability.

11.3 Environmental and social impact conclusions

Impacts during construction are evaluated based on their likelihood, duration, and scale, with specific consideration given to the potential environmental, social, and economic consequences. The table below provides a structured overview of the expected impacts, categorizing them by air quality, water resources, soil and land use, biodiversity, waste management, social aspects, and cultural heritage. Each category includes a description of the potential effects, along with an assessment of their severity and mitigation strategies. This approach ensures that appropriate measures are

integrated into the project planning and execution to minimize negative consequences and enhance sustainability and community well-being.

IMPACT AREA AND CHARACTERISTICS IN THE CONSTRUCTION PHASE

IMPACT AREA	LIKELIHOOD, DURATION, SCALE	DESCRIPTION
Ambient air and microclimate	Likely, short-term, local	Dust particles emitted during installation and earthworks, as well as exhaust gases from internal combustion engines, could affect air quality temporarily.
Water environment	Unlikely, short-term, local	No direct work is performed near water bodies or protected areas.
Soils, geology, and land resources	Likely, short-term, local	Soil compaction and potential temporary land acquisition may occur for equipment staging and material storage, which could lead to minor degradation.
Protected areas and biodiversity	Unlikely	The project is confined to urban and industrial areas, not affecting natural reserves or biodiversity-rich zones.
Flora	Likely, short-term, local	Potential tree removal or trimming in areas adjacent to construction sites may occur. Measures for compensation and replanting are planned.
Fauna	Unlikely	Construction activities are limited to anthropogenically modified areas with minimal wildlife presence.
Waste management	Moderate, short-term, local	Construction and demolition debris, hazardous waste from equipment, and excess materials will be managed according to established protocols to prevent pollution.
Social aspects	Likely, short-term, local	Noise, vibration, and restricted access to nearby areas may temporarily inconvenience residents and businesses.
Cultural heritage	Unlikely	No direct impact on cultural heritage is expected unless construction standards are violated.

The environmental and social assessment for the operational phase of the project highlights anticipated positive impacts on key areas while ensuring minimal disruption to the surrounding environment and communities. These impacts are assessed based on their likelihood, duration, and geographic scale, emphasizing long-term benefits and localized mitigation strategies. The table below outlines the projected effects across various domains, including air quality, water resources,

soil and land use, biodiversity, waste management, social aspects, and cultural heritage. By incorporating advanced technologies and sustainable practices, the project aims to enhance environmental performance and community well-being, while maintaining compliance with environmental standards and regulatory requirements.

IMPACT AREA AND CHARACTERISTICS IN THE OPERATIONAL PHASE

IMPACT AREA	LIKELIHOOD, DURATION, SCALE	DESCRIPTION
Ambient air and microclimate	Likely, long-term, regional	Improved air quality is expected due to advanced filtration systems and renewable energy integration; minor emissions from the WtE plant will be mitigated by technology.
Water environment	Likely, long-term, local	Efficient water management practices will reduce consumption and discharge. Water reuse systems will mitigate the impact on nearby water bodies.
Soils, geology, and land resources	Unlikely	The operational phase will not involve activities that disturb soil or geology.
Protected areas and biodiversity	Absent	No impact is expected, as operations are confined to industrial and urban zones.
Flora	Likely, long-term, local	Regular maintenance of green zones, including tree replacement or trimming, to minimize visual impact and improve environmental aesthetics.
Fauna	Unlikely	Minimal impact, as operations are conducted in developed areas with limited wildlife presence.
Waste management	Likely, long-term, local	Sustainable waste management protocols for the WtE plant will reduce landfill reliance, with periodic monitoring to ensure compliance with environmental standards.
Social aspects	Likely, long-term, regional	Improved energy reliability and reduced dependency on fossil fuels will enhance local quality of life, but periodic maintenance may cause minor inconveniences.
Cultural heritage	Unlikely	No direct interaction with cultural heritage sites; visual and noise impact mitigation measures ensure preservation of nearby cultural landmarks.

11.4 Mitigation measures

The reconstruction of the combined heat and power plant (CHP) and the associated installations in the field of green energy in Chisinau aim to improve the city's energy infrastructure, enhancing

energy efficiency and transitioning towards more sustainable energy solutions. However, the initiative is accompanied by potential environmental and social risks that require careful management. A comprehensive mitigation and management plan has been developed to minimize the project's negative impact on the environment and public health, ensuring compliance with the standards and requirements set forth by the World Bank and other international best practices.

Table 11-1. Mitigation and management plan

Aspect	Mitigation Action Plan	Responsible Party	World Bank ESS Reference
Air Pollution Monitoring	• Use advanced air quality sensors for continuous monitoring. • Install sensors strategically across project sites to measure emissions during construction.	• Contractor responsible for monitoring; oversight by Project Owner.	• ESS3: Resource Efficiency and Pollution Prevention
Dust Mitigation	• Irrigate internal dirt roads with industrial water. • Develop optimal routes for construction equipment to minimize dust emissions. • Cover or protect temporary storage of dusty materials.	• Contractor responsible for dust control measures.	• ESS4: Community Health and Safety
Noise Control	• Equip machinery with noise suppressors. • Restrict noisy activities to daytime hours (8 a.m.–6 p.m.). • Install noise barriers near construction zones when necessary.	• Contractor responsible for compliance; Project Owner to ensure oversight.	• ESS4: Community Health and Safety
Waste Management	• Develop and implement a Waste Management Plan for sorting, reuse, and disposal. • Store waste according to hazard classes in designated areas. • Appoint a waste management officer at the site to oversee operations.	• Contractor responsible for waste handling; monitored by Environmental Agency.	• ESS3: Resource Efficiency and Pollution Prevention
Soil Protection	• Prevent construction equipment from moving off designated roads. • Conduct regular inspections to avoid accidental spills of fuels and lubricants. • Store liquid waste in sealed containers to prevent contamination.	• Contractor responsible for site operations; Project Owner to verify compliance.	• ESS6: Biodiversity Conservation
Water Resource Management	• Ensure wastewater is discharged into designed storage tanks. • Monitor water quality in surrounding water bodies. • Avoid direct runoff from construction sites into watercourses.	• Contractor responsible for ensuring water safety; oversight by Environmental Agency.	• ESS3: Resource Efficiency and Pollution Prevention
Emergency Preparedness	• Develop an Emergency Response and Contingency Plan for spills, leaks, or accidents. • Install warning signs, plaques, and fences around construction sites.	• Contractor responsible for safety measures; local authorities to assist.	• ESS4: Community Health and Safety

Aspect	Mitigation Action Plan	Responsible Party	World Bank ESS Reference
Worker Health and Safety	• Provide safety gear such as helmets, gloves, masks, and earplugs. • Conduct safety briefings and training before construction begins. • Ensure the availability of first aid kits at work sites.	• Contractor responsible for providing safety measures and training.	• ESS2: Labor and Working Conditions
Community Engagement	• Conduct consultations with local communities before construction begins. • Disseminate information on the project timeline, potential disruptions, and mitigation measures.	• Contractor responsible for outreach; supported by local authorities.	• ESS10: Stakeholder Engagement and Information Disclosure
Cultural and Aesthetic Preservation	• Ensure temporary storage of materials and machinery does not disrupt local aesthetics. • Respect community holidays and cultural practices during the project timeline.	• Contractor responsible for cultural sensitivity; Project Owner to monitor adherence.	• ESS8: Cultural Heritage
Labour and Wage Management	• Ensure equal pay and employment opportunities for all genders. • Prioritize local hiring to reduce social tensions.	• Contractor responsible for compliance; monitored by Project Owner.	• ESS2: Labor and Working Conditions
Cumulative Risk Management	• Coordinate construction schedules to avoid overlapping impacts from CHP, WtE, and Solar Fields. • Implement monitoring systems to track combined emissions and noise levels.	• Contractor responsible for coordination; oversight by Project Owner and relevant agencies.	• ESS1: Assessment and Management of Environmental and Social Risks and Impacts

This table integrates the mitigation strategies into actionable steps aligned with World Bank Environmental and Social Standards to ensure environmentally and socially sustainable implementation of the project.

12. Conclusion

The feasibility study for the development of a new **Combined Heat and Power (CHP)** plant in Chisinau comprehensively analyzed multiple technical and economic configurations to determine the most optimal solution for long-term energy efficiency, cost-effectiveness, and sustainability. The study evaluated five CHP configurations based on **technical feasibility, economic viability, environmental impact, and operational flexibility**.

12.1 Technical and Economic Evaluation

Among the analyzed variants, **CHP Type 2** (3 × SGT800 + 3 × HRSB + ST) demonstrated the most balanced performance in terms of operational reliability, efficiency, and financial viability. The maximum electrical output for this configuration is **246 MW**, with a **maximum thermal output of 180 MW** and an **overall efficiency of 87.6%**. The **electrical efficiency in condensing mode is 54.3%**, making it highly suitable for electricity market participation.

From a financial perspective, **CHP Type 2** provides the highest **Net Present Value (NPV) of €250,9 million**, outperforming other variants in terms of long-term profitability. The Internal Rate of Return (IRR) is 11,65 %, indicating strong investment attractiveness. Furthermore, the Levelized Cost of Heat (LCOH) with fuel price (natural gas plus emissions) at €50/MWh is €39,8/MWh, making it the most cost-competitive solution in terms of heat production.

12.2 Comparison with Alternative Configurations

While CHP Type 5 offers high overall efficiency and operational flexibility, its lower electrical efficiency and higher reliance on heat revenues make it more sensitive to variations in electricity prices. In scenarios where heat prices remain favorable, CHP Type 5 delivers competitive returns due to its high thermal efficiency and lower electricity-to-heat ratio. However, in situations where electricity prices increase, CHP Type 2 outperforms due to its superior electrical efficiency, enabling higher electricity revenues for the same thermal output.

12.3 Environmental and Operational Benefits

The selected CHP configuration aligns with Moldova's climate change mitigation strategy by replacing the existing low-efficiency steam-based generation at CHP Source 1 and CHP Source 2. The project is expected to result in significant CO_2 emissions reductions, improve the resilience of the district heating system, and enhance energy security by incorporating Thermal Energy Storage (TES) and Waste-to-Energy (WtE) components.

Additionally, the modular design of CHP Type 2 ensures operational flexibility, allowing for partial load operation during periods of lower demand, thereby optimizing fuel consumption and reducing operational risks.

12.4 Investment and Implementation Outlook

The CHP Type 2 (including TES) project will require a capital investment of approximately €342 million (or approximately €347 million, including reserve fuel storage), making it one of the most substantial infrastructure investments in Moldova's energy sector. Given the positive financial indicators and strong sensitivity analysis results, the implementation of CHP Type 2 is recommended as the most resilient and economically viable option.

With an expected payback period of approximately 8 years and robust financial performance across various market and fuel price scenarios, this investment represents a strategic step towards

modernizing Moldova's energy infrastructure, ensuring both economic sustainability and long-term operational efficiency.

12.5 Final Recommendation

Based on a comprehensive techno-economic and environmental assessment, CHP Type 2 is the preferred solution for the Chișinău district heating system. Its high efficiency, competitive financial performance, and operational flexibility make it the most sustainable choice to replace the aging power infrastructure. The integration of TES along with complementary options (heat pump, WtE and solar thermal) further enhances system reliability and environmental performance, positioning Chișinău as a regional leader in modern CHP deployment.

12.6 Further Steps for Project Implementation

To ensure a successful and risk-mitigated implementation of the new CHP plant in Chișinău, a structured approach is required, considering the regulatory framework, financing mechanisms, and technical complexities specific to Moldova. The proposed steps prioritize de-risking the project for future EPC (Engineering, Procurement, and Construction) contractors, ensuring cost-efficiency and compliance with both Moldovan and international best practices. Additionally, the necessary steps for the Thermal Energy Storage (TES) system will be outlined, as it plays a crucial role in enhancing system efficiency and flexibility.

12.6.1 Natural gas connection

The feasibility of supplying high-pressure natural gas to the new CHP Type 2 at the site of the existing CHP Source 1 is currently limited by the available infrastructure and urban planning restrictions. At present, only a low-pressure gas pipeline is in place, which is insufficient to meet the operational requirements of the new CHP. While the installation of a high-pressure (50 bar) pipeline is technically feasible, the spatial plan of Chisinau does not currently allow for its construction through urban areas.

Regulatory and Safety Considerations

In accordance with ISO 13623, the design and installation of high-pressure gas pipelines must take into account population density and urban development along the pipeline route. The standard categorizes areas based on urbanization levels, with higher population density and taller buildings necessitating stricter pipeline safety measures. These include increased pipeline wall thickness, deeper burial depth, and more rigorous testing procedures, such as pressure testing and weld inspections.

Furthermore, ISO 13623 defines the methodology for determining population density and high-occupancy buildings, such as hospitals, schools, and religious institutions, to ensure public safety. The successful implementation of a high-pressure gas pipeline through Chisinau's urban area would require full compliance with these safety provisions. The precedent of similar urban high-pressure pipelines, such as the Botinec–ELTO gas pipeline in Zagreb (Croatia), demonstrates that such projects can be implemented safely with proper planning and adherence to international standards.

Necessity of Spatial Plan Amendment

Given the long-term energy needs of Chisinau and the importance of securing a stable and efficient fuel supply for CHP Type 2, it is advised to revise the spatial plan to allow for the construction of a high-pressure gas pipeline. This revision should be based on:

- Application of ISO 13623 Safety Standards

- Strategic Routing and Impact Mitigation
- Stakeholder Engagement and Regulatory Approval
- Long-Term Economic and Environmental Benefits

To ensure the long-term reliability of gas supply for CHP Type 2 and support the city's energy infrastructure development, the spatial plan of Chisinau should be revised to allow for the construction of a high-pressure gas pipeline. The project should be designed in accordance with ISO 13623 and other relevant safety standards to ensure full compliance with international best practices. With proper planning, risk assessment, and regulatory coordination, the pipeline can be constructed safely, providing a long-term solution for Chisinau's district heating and power generation needs.

12.6.2 Basic Design Development, Grid Connection & Environmental and Social Impact Assessment (ESIA)

Before initiating the tendering process, the first critical step is to develop the Basic Design, which should encompass:

- Technical Design Definition:
  - Establishing key plant configurations, including CHP unit specifications, district heating integration, and operational performance parameters.
  - Determining fuel supply logistics and emissions control systems.
  - Outlining Thermal Energy Storage (TES) system integration, ensuring compatibility with the CHP's operational flexibility.
- Electrical Grid Connection Design & Approval:
  - Conducting a grid impact study to evaluate the CHP's connection to Moldova's national transmission and distribution networks.
  - Defining the required grid infrastructure investments, including transformers, substations, and reinforcement measures.
  - Coordinating with Moldelectrica and regulatory authorities to obtain approvals for grid access, ensuring compliance with grid stability and frequency control requirements.
  - Assessing electricity market participation, evaluating strategies for power export vs. local consumption.
- Environmental and Social Impact Assessment (ESIA):
  - Conducting an in-depth environmental impact assessment covering:Air emissions, CO_2 reduction potential, and noise impact
  - Water usage and thermal discharge effects
  - Community and social engagement aspects
  - Engaging with relevant Moldovan authorities (ANRE, Ministry of Energy, Ministry of Environment) to obtain necessary permits and approvals.

Developing the Basic Design and resolving grid connection issues early will significantly reduce risks for EPC contractors, ensuring that bidders have well-defined project parameters, leading to more competitive offers and a smoother implementation phase.

12.6.3 Securing Financing and Investment Structuring

Given the CAPEX for CHP Type 2 (including TES) approximately €342 million (or approximately €347 million, including reserve fuel storage), a well-structured financing plan must be developed in parallel with the Basic Design to prevent delays. The financing approach should consider:

- International donor support (World Bank, EBRD, EIB, EU Green Deal funding)
- Moldovan government contributions and tariff-based financing
- Private sector involvement (via PPP or concessional arrangements)
- Alignment with Moldova's Energy Strategy 2030, ensuring long-term affordability and minimal tariff impacts.
- Preparation of funding applications for grants or concessional loans should commence early, especially for the grid connection infrastructure, which may qualify for international funding under energy transition and decarbonization programs.

12.6.4 Tendering Process for EPC Contractor

Once Basic Design is finalized and financing is secured, the tendering process for construction should be launched under a transparent and competitive procurement framework, ensuring international best practices and risk allocation:

- Prepare a detailed tender package, including:
  - Technical specifications, performance guarantees, and reliability criteria.
  - Clear contractual obligations, especially in terms of grid compliance and connection timelines.
  - Defined scope of work for EPC + O&M (Operations and Maintenance) support, ensuring long-term plant efficiency.
- Conduct prequalification of bidders to ensure that only technically and financially capable companies participate.
- Enable different gas turbine configurations (two or three gas turbines) to ensure competition between OEMs
- Organize a competitive bidding process, ensuring compliance with both Moldovan public procurement regulations and international lender requirements (if external financing is used).
- Award EPC contract and mobilize construction activities, ensuring clear milestones and independent supervision of progress.

12.6.5 Further Steps for Thermal Energy Storage (TES)

Since TES is an integral component of the new CHP system, optimizing efficiency and demand-side flexibility, its development should be handled in parallel with the CHP plant implementation. The key steps include:

- Preliminary Feasibility and Design:
  - Identify space and integration constraints, ensuring that TES placement does not interfere with CHP plant operations.
- Regulatory & Financial Structuring:
  - Secure necessary permits and approvals from Moldovan energy regulators.

- Assess eligibility for international co-financing opportunities, particularly through EU decarbonization grants or EBRD green financing instruments.
- Develop a cost-benefit analysis to justify TES integration, demonstrating potential fuel savings and emission reductions.

- Tendering and Implementation:
  - Issue a separate EPC tender for TES, ensuring compatibility with the CHP system's operational framework.
  - Oversee construction and commissioning, ensuring seamless integration into district heating operations.