Co-funded by the European Union
Research Fund for Coal & Steel

Hybrid energy storage system using post-mining infrastructure (HESS)

HESS

D.7.1. Techno-economic assessment of hybrid energy storage technology in postmining infrastructure

30.06.2026

PROJECT	
Project number	**101112380**
Project name	**Hybrid energy storage system using post-mining infrastructure**
Project acronym:	**HESS**
Call	**RFCS-2022**
Topic	**RFCS-01-2022-RPJ**
Type of action	**RFCS-PJG**
Service	**REA/B/01**

DOCUMENT PROPERTIES

Document	
Document Title	**Techno-economic assessment of hybrid energy storage technology in postmining infrastructure**
Document responsible	**ITPE**
Document authors	**Tomasz Billig Krzysztof Głód Agata Czardybon Janusz Lasek Aleksander Krótki Szymon Dobras Magdalena Dobras Piotr Matusiak Daniel Kowol Konrad Kołodziej Marcin Lutyński Jakub Ochmann Michał Jurczyk Krzysztof Rusin**
Data of the document	**30.06.2026**

Table of contents

List of Figures

List of tables

1. Technical analysis

1.1. HESS technology concept design

The proposed Hybrid Energy Storage System (HESS) is an integrated, multi-carrier energy storage concept based on the use of existing post-mining infrastructure, in particular mine shafts and available underground spaces, as functional elements of an energy storage installation. The concept assumes that selected components of former or active mining infrastructure can be adapted for energy storage purposes, reducing the need for new large-scale civil engineering works and supporting the reuse of industrial assets in the energy transition process.

As part of the project, an analysis of available mine shafts in three countries (Poland, Czech Republic and Slovenia) was carried out to identify the most suitable location for the implementation of the HESS concept. Based on technical, geological, infrastructural and operational criteria, the Budryk mine (II and III Shaft) was selected as the reference case for further technical, economic and environmental analyses.

The HESS is designed as a system in which energy is stored and converted in three complementary forms: potential energy, pressure energy and thermal energy. The system integrates three interoperable subsystems, each with a minimum storage capacity of 10 MWh:

- *Pumped Storage Hydropower (PSH),* using mine shafts to create hydraulic head and store energy in the form of water potential energy;
- *Compressed Gas Energy Storage*, implemented as *CAES* using the air or *CCES* using carbon dioxide as the working medium;
- *Thermal Energy Storage (TES),* used to recover, store and reuse heat generated or required during gas compression and expansion.

The project considers two operating scenarios. In the first scenario, the system operates as an adiabatic CAES configuration using the air. In the second scenario, CO_2 is used as the working medium, forming a CCES configuration. The comparison of both variants enables the assessment of technical, energetic, economic and environmental differences, including compression parameters, storage pressure, thermal requirements, safety aspects, efficiency and environmental impact.

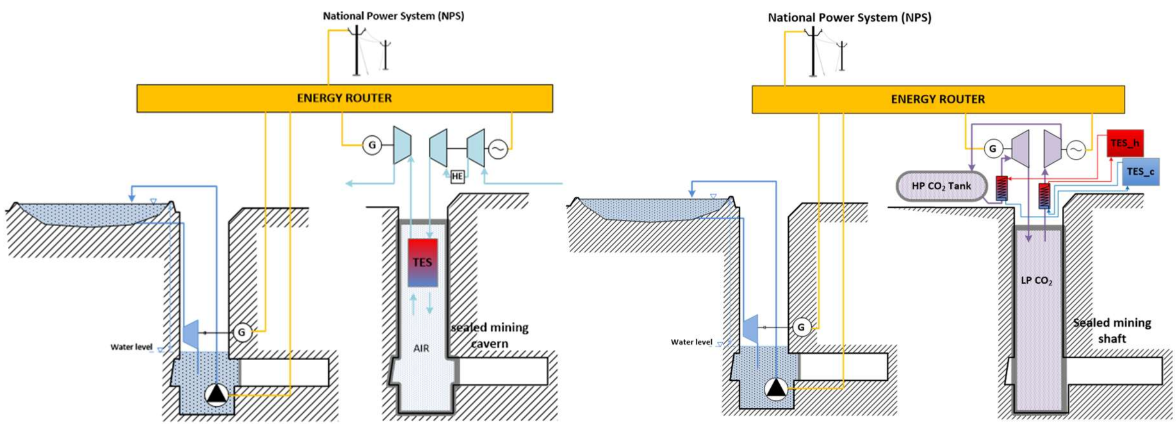

Fig. 1 HESS operation diagram in two variants.

The system operates according to the principle of adiabatic energy storage, where the recovery and reuse of process heat are essential. During the charging phase, surplus electricity is used to compress air or CO_2, while the heat generated during compression is transferred to the TES subsystem. During the discharging phase, the compressed gas is reheated using stored thermal energy before expansion in the turbine-generator unit. This approach reduces thermal losses, improves energy recovery efficiency and limits the need for external heat sources.

In the PSH subsystem, the mine shaft acts as a structural element of the hydropower system. The lower reservoir is located at the bottom of the shaft, while the upper reservoir is located on the surface. Water is transported through a vertical pipeline installed in the shaft. In charging mode, electricity powers pumps that transfer water to the upper reservoir. In discharging mode, water flows by gravity through the turbine-generator unit, producing electricity. The use of existing mine infrastructure enables high hydraulic pressure, lower land use and reduced investment costs compared with conventional pumped storage solutions.

The compressed gas storage subsystem provides high energy capacity. In the CAES variant, compressed air is stored in in the mine shaft. In the CCES variant, CO_2 is stored in low-pressure and high-pressure sections, potentially under conditions enabling higher energy density and reduced storage volume. Both variants require integration with the TES subsystem, as heat recovered during compression is later used during expansion to increase power output and improve system efficiency.

The TES subsystem acts as a thermal buffer for the compressed gas storage process. It stores heat generated during compression and supplies it back during gas expansion. In the proposed concept, TES is integrated with the air storage volume in the mine shaft in CAES, enabling compact system architecture and efficient use of available underground space. Its function is critical for improving the round-trip efficiency of the subsystem. In the CCES configuration, the thermal energy storage (TES) system is installed on the surface, outside the mine, and consists of two storage tanks.

A key element of the HESS is the intelligent energy router, which acts as the central integration, control and optimization unit. It manages electrical, mechanical and thermal energy flows between the HESS, the power system and individual storage subsystems. The router determines the optimal operating mode based on electricity demand, availability of surplus energy, state of charge of each subsystem, pressure and temperature levels, water levels, technical constraints, safety conditions and efficiency criteria. In charging mode, the router directs electricity to the PSH pumps and/or CAES/CCES compressors and coordinates heat transfer to TES. In discharging mode, it manages electricity generation from the PSH turbine and the compressed gas expander, while coordinating the supply of heat from TES to the expansion process. The router also supports hybrid operation, allowing more than one subsystem to operate simultaneously depending on system needs. In addition to energy management, the router performs monitoring, diagnostic and safety functions. It collects data on power flows, pressures, temperatures, water levels, gas storage conditions, thermal storage status and equipment availability. If operating limits are exceeded, it can reduce load, change the operating mode, disconnect a subsystem or initiate safe shutdown procedures.

The integrated HESS system provides high energy efficiency through the synergy of complementary storage technologies and effective use of thermal energy. It is also characterized by operational flexibility, as PSH can support fast response and short-term balancing, CAES/CCES can provide larger energy capacity, and TES improves the efficiency of the compressed gas cycle. The system is scalable and can be adapted to different geological and geometric conditions of mine shafts.

The proposed technology supports the energy transition by enabling the storage of surplus renewable energy, improving power system stability and giving post-mining infrastructure a new energy function. By combining PSH, compressed gas storage and TES within one coordinated system, HESS is intended to offer greater flexibility and higher functionality than individual storage technologies operating separately.

1.2. Technical description of the Hybrid Energy Storage System

1.2.1. Technological diagram of HESS 1 variant: PSH with CAES/TES

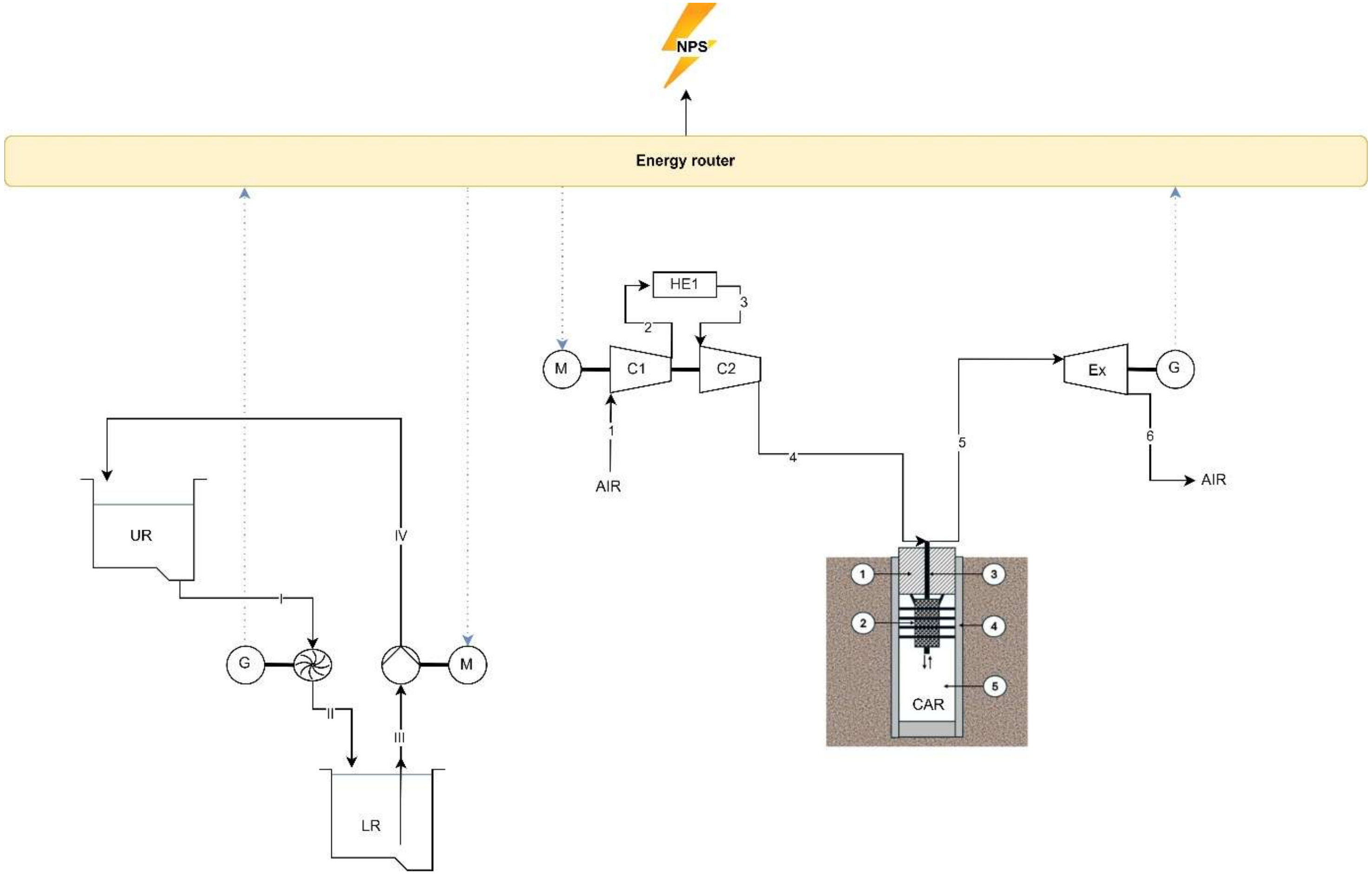

Fig. 2 Schematic diagram of PSH and CAES/TES subsystems (symbol description is given below).

Symbols (Fig. 2):

➢ ***Equipment and Devices***

System PSH (Pumped Storage Hydropower – the left side of Fig. 2):

- UR (Upper Reservoir): Upper reservoir, located on the surface.
- LR (Lower Reservoir): Lower reservoir, formed in the bottom of a mine shaft.
- G (Generator): Synchronous generator coupled to the turbine.
- Turbine (rotor icon): Vertical Pelton turbine.
- M (Motor): Motor driving the pump system.
- Pump (pump icon): System of deep-well dewatering pumps.

System A-CAES (Adiabatic Compressed Air Energy Storage – the right side of Fig. 2):

- M (Motor): Electric motor driving the compressor sections.
- C1: Low-pressure section of the centrifugal compressor.
- C2: High-pressure section of the centrifugal compressor.
- HE1: Shell-and-tube intercooler.
- Ex (Expander): Air expander (converted steam turbine).
- G (Generator): Electric generator coupled to the expander.
- Energy Router: Intelligent node managing the flow of electrical and thermal energy.

Installation in the shaft (numbers 1–5):

1. Shaft plug: A reinforced concrete seal that closes off the pressurized section of the shaft.
2. TES (Thermal Energy Storage) tank: A segmented, columnar heat storage tank filled with basalt.
3. Inlet/outlet pipeline: A pipe that supplies and removes air to and from the shaft.
4. Shaft casing: The load-bearing structure of the pressure vessel.
5. CAR (Compressed Air Reservoir): The active volume of the shaft serving as a compressed air reservoir.

➢ ***Description of streams***

Water streams (PSH):

I: Water flowing by gravity from the upper reservoir (UR) to the Pelton turbine.
II: Water discharged from the turbine to the lower reservoir (LR) through the shaft.
III: Water drawn from the lower reservoir by the pump system.
IV: Water pumped back to the upper reservoir through the discharge pipeline.

Air Flows (CAES):

1: Atmospheric air intake through the filter.
2: Air after the first compression stage (C1) directed to the cooler (HE1).
3: Cooled air entering the high-pressure section (C2).
4: Hot, compressed air (up to 500°C) forced into the shaft through the TES bed.
5: Air heated in the TES bed during system unloading is directed to the expander.
6: Air, after expansion in the turbine, is discharged into the atmosphere.

1.2.2. Technical description of HESS 1 variant: PSH and CAES/TES subsystems

System overview and reference infrastructure

The Hybrid Energy Storage System (HESS) is an integrated, multi-carrier energy storage architecture designed to leverage decommissioned post-mining infrastructure for large-scale grid stabilization. By utilizing existing mine shafts and underground cavities, the system converts electricity into three primary forms: gravitational potential energy (water), pressure energy (compressed gas), and thermal energy (sensible heat). This integration maximizes the reuse of industrial assets, significantly reducing the capital expenditure (CAPEX) associated with new civil engineering works while supporting the transition toward a decentralized energy economy.

The reference location for this implementation is the Budryk mine, specifically Shafts II and III. Shaft II is repurposed for the Pumped Storage Hydropower (PSH) subsystem, while Shaft III is adapted into a high-pressure vessel for the Adiabatic Compressed Air Energy Storage (A-CAES) and Thermal Energy Storage (TES) subsystems. The HESS operates as a unified plant, where energy is stored during periods of surplus generation and discharged according to National Power System (NPS) demand, managed by a central intelligent energy router. Basic technological parameters is shown at the Table 1.

Table 1 Basic technological parameters.

Parameter	Pumped Storage Hydropower (PSH)	Adiabatic CAES (A-CAES)
Reference location	Budryk Mine (Shaft II)	Budryk Mine (Shaft III)
Storage medium	Water	Compressed Air
Energy storage capacity	23.06 MWh	108 MWh
Operating cycle	Daily	Daily
Production efficiency	60.01%	65.00%
Maximum operating pressure	8.2–10.0 MPa (at turbine)	5.0 MPa (storage vessel)
Charging/discharging time	8h (pumping) / 4h (generation)	5h (charging) / 3h (discharging)

<u>**Pumped Storage Hydropower (PSH) subsystem**</u>

Component identification (diagram labels)

The PSH module utilizes Shaft II (1,157.45 m depth) to facilitate high-head hydraulic storage. Following the labels on Fig. 2:

- UR (Upper Reservoir): an open-surface storage facility partially embedded in the terrain. It stores the working fluid at the surface level, acting as the primary head source for the discharging phase.
- LR (Lower Reservoir): an underground basin established at the shaft bottom (approx. 1157 m) with an operational working volume of 12,000 m³. It is reinforced to handle cyclic filling and high hydrostatic loads.

- G (Synchronous Generator): a 5.8 MW, 6.3 kV electrical unit coupled to the Pelton turbine. It operates at 1500 rpm and is equipped with an automatic voltage regulation system to ensure grid synchronization.
- M (Motor): a high-voltage drive unit powering the deep-well pumping system. The system incorporates specialized OS 100/5, OW 200/7, and OWH 200/10 pumps.
- Turbine (Vertical Pelton Turbine): a high-efficiency impulse turbine (model PV3i-790-160) with three needle-controlled nozzles. The runner is fabricated from high-strength stainless steel resistant to erosive wear, ensuring high durability under the rated 0.71 m^3/s flow rate and 91% efficiency.

Water flow analysis (Streams I-IV)

The PSH cycle moves water through specific pressure-rated zones to manage the 900 m design head (Table 2).

Table 2 Water flow streams in the PSH system during charging and discharging operation.

Stream ID	Phase	Direction	Purpose/State
Stream I	Discharging	UR to Turbine	High-pressure gravity flow through the DN400 penstock.
Stream II	Discharging	Turbine to LR	Discharge into the shaft bottom after kinetic energy extraction.
Stream III	Charging	LR to Pump	Intake of water from the lower reservoir to the pumping assembly.
Stream IV	Charging	Pump to UR	Return flow to the surface via a three-stage sequence.

Technical specifications of transport

- Pressure Zonation: the DN400 pressure pipeline is segmented into three zones to manage hydrostatic stress: PN40 (surface to 326m), PN63 (326m to 570m), and PN100 (570m to the turbine level).
- Pumping Sequence: the charging phase utilizes a staged ascent: Level 1158m → 1050m; Level 1050m → 700m; and Level 700m → Surface.

<u>Adiabatic compressed air energy storage (A-CAES) subsystem</u>

Subsurface pressure vessel and TES components

- Shaft III is structurally modified to serve as an airtight vertical reservoir. Components identified on Fig. 2 include:
- Shaft Plug: a 100m high monolithic barrier made of C30/37 class concrete with dispersed reinforcement. It is anchored to the rock mass via 220 ground anchors (S355 steel, 12m length) and 8 reinforced-concrete thrust footings.
- TES Tank (Thermal Energy Storage): a segmented cylindrical steel structure (5.0m ID) containing a basalt packed bed.
  - Basalt Density: 2768 kg/m^3.
  - Mean Grain Size: 16 mm.
  - Specific Heat Capacity: 970 J/(kg·K).
  - Porosity & Resistance: 0.38 porosity; thermal resistance confirmed > 800°C.

- Inlet/Outlet Pipe & Bellows: a DN5000 assembly featuring axial bellows connecting the 5.0m diameter TES segments to compensate for thermal elongation.
- Shaft Casing: original lining reinforced with reprofiled shotcrete to ensure structural integrity under cyclic pressure.
- CAR (Compressed Air Reservoir): the active pressurized volume below the shaft plug, capable of storing gas up to 5.0 MPa.

Air and heat flow analysis (Streams 1-6)

The A-CAES subsystem utilizes an adiabatic cycle, where the heat of compression is stored in the TES and reused during expansion, eliminating external fuel requirements.

- Charging (Streams 1-4): atmospheric air is drawn (1) into the C1 compressor, reaching 0.4 MPa and 155°C (2). After intercooling in HE1 to 30°C (3), the C2 compressor raises the pressure to 5.0 MPa and temperature to 500°C. This high-temperature air (4) passes through the TES, depositing heat into the basalt bed before entering the CAR.
- Discharging (Streams 5-6): air is released from the CAR and directed back through the TES (5). The air is preheated to 500°C using the stored thermal mass before entering the Expander (Ex). The expanded air is then exhausted (6).

Integration via the intelligent energy router

The Intelligent Energy Router is the central control hub coordinating the HESS subsystems with the National Power System (NPS). It manages the "adiabatic" nature of the plant by ensuring the thermal energy stored in the TES is precisely synchronized with the expansion process.

Router optimization and coordination criteria:

- State of Charge (SoC) Balancing: simultaneous management of water levels (PSH) and air pressure/thermal levels (A-CAES).
- Adiabatic Synchronization: during discharge, the router optimizes the supply of heat from the TES to the expansion process to maximize the inlet enthalpy at the expander (Ex).
- Operational Safety: monitors limits (5.0 MPa, 500°C) and handles safe shutdown if deviations are detected in the shaft casing or plug sensors.
- Market Dispatch: aligns charging/discharging cycles with electricity demand and surplus generation availability.

Summary of System Performance and Efficiency

The HESS transformation of the Budryk mine infrastructure provides a scalable solution for long-duration energy storage. The system demonstrates high volumetric efficiency by utilizing the significant depths and volumes available in legacy shafts.

Table 3 Key design parameters of the PSH and CAES/TES.

Metric	PSH Subsystem	A-CAES Subsystem
Storage Capacity, MWh	23.06	108
Production Efficiency, %	60.01	65.00
Volumetric Energy Density, MWh/m³	0.155 (LR+UR)	0.489 (HTP+LPT)
Rated Power Output, MW	5.8 (Generator)	36 (Expander)
Thermal Storage Mass, t	N/A	1,347 (Basalt)

The integration of PSH and A-CAES within a single coordinated framework allows for both rapid-response balancing and large-scale capacity delivery. By utilizing the 900m hydraulic head and 5.0 MPa gas storage volume, the HESS provides a high-density alternative to traditional energy storage, successfully repurposing heavy industrial assets for the renewable energy transition.

1.2.3. Technological diagram of HESS 2 variant: PSH with CCES/TES

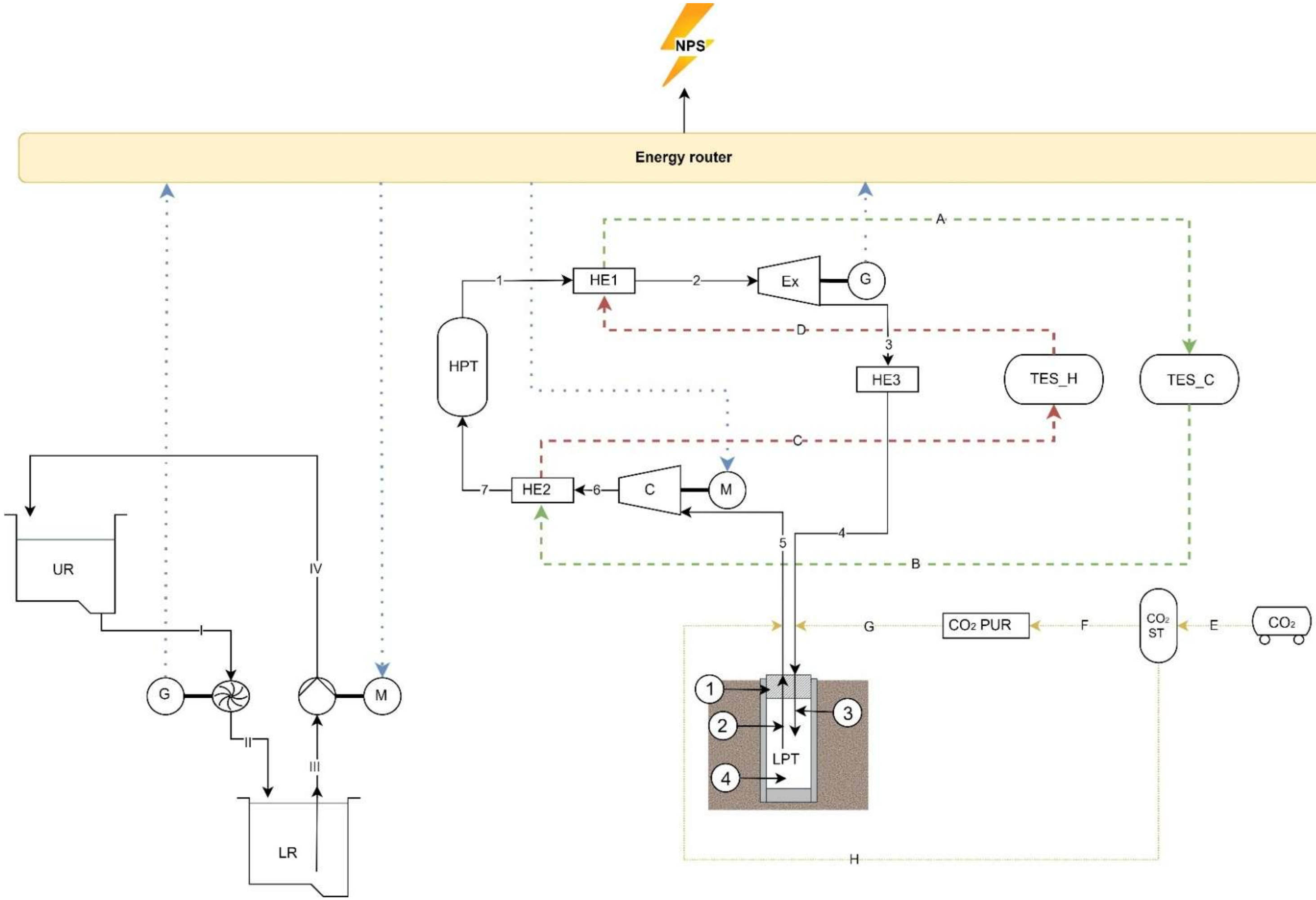

Fig. 3 Schematic diagram of PSH and CAES/TES subsystems (symbol description is given below).

Symbols (Fig. 3):

➢ ***Equipment and Components (PSH CCES)***

PSH Subsystem (Left side of the diagram):

- UR (Upper Reservoir): Surface-level water storage.
- LR (Lower Reservoir): Underground water storage located in the mine shaft.
- Turbine (Pelton type): Vertical impulse turbine driven by water flow.
- G (Generator): Synchronous generator producing electricity during discharge.
- M (Motor): Electric motor powering the pumping system.
- Pump: Multi-stage dewatering system (e.g., OW, OWH types) transferring water back to the surface.

CCES Subsystem (Right side of the diagram):

- HPT (High-Pressure Tank): A cluster of above-ground isobaric cylinders storing supercritical CO_2 at approx. 8.0 MPa.
- LPT (Low-Pressure Tank): The mine shaft acting as an underground isobaric vessel for gaseous CO_2 at approx. 0.64 MPa.
- C (Compressor): Single-section centrifugal machine for CO_2 compression.
- Ex (Expander): Single-section turbine converting CO_2 energy into shaft work.
- HE1 (Heat Exchanger 1): Preheats supercritical CO_2 before expansion using heat from the TES.
- HE2 (Heat Exchanger 2): Recovers compression heat from CO_2 and transfers it to the TES.
- HE3 (Heat Exchanger 3): Additional cooler/integrator for district heating or deep cooling.
- TES_H (Hot Thermal Energy Storage): Tank containing hot synthetic oil (Therminol VP-1) and basalt bed.
- TES_C (Cold Thermal Energy Storage): Tank containing cold synthetic oil and basalt bed.
- CO_2 PUR: Cryogenic CO_2 purification unit to remove moisture and impurities (CH_4, N_2, O_2).
- CO_2 ST: Cryogenic storage tanks for liquid CO_2 replenishment.
- Energy Router: Central control unit managing energy flows and grid connection (NPS).

Installation in the shaft (numbers 1-4)

- 1 – Shaft sealing: A reinforced concrete seal that closes off the pressurized section of the shaft.
- 2 – CO_2 inlet: A pipe that supplies carbon dioxide to the shaft.
- 3 – CO_2 outlet pipe: A pipe that removes from the shaft.
- 4 – LPT / Low-pressure vessel: The active storage volume within the adapted mine shaft.

➢ ***Process Streams Description***

CO_2 Circuit (Numbers 1–7):

- 1: Supercritical CO_2 leaving the HPT during the discharge phase.
- 2: CO_2 preheated in HE1 directed to the expander (Ex).
- 3: Low-pressure CO_2 after expansion, directed through HE3.
- 4: CO_2 returning to the underground LPT for storage.
- 5: CO_2 drawn from the LPT during the charging phase.
- 6: Hot, compressed CO_2 directed to HE2.
- 7: Supercritical CO_2 cooled in HE2, flowing back to the HPT.

Thermal Oil/Cooling Circuit (Letters A–D):

- A: Cold oil flow from TES_C to HE1.

- B: Cold oil flow from TES_C to HE2.
- C: Hot oil flow from HE2 to TES_H (storing compression heat).
- D: Hot oil flow from TES_H to HE1 (supplying heat for expansion).

CO_2 Supply and Purification (Letters E–H):

- E, F, G: Path of CO_2 from external supply through storage and purification into the main system loop.
- H: Feedback/monitoring line between LPT and the purification system.

1.2.4. Technical description of HESS 2 variant: PSH and CCES/TES subsystems

Executive system overview

The Hybrid Energy Storage System (HESS) is an integrated, multi-carrier technological architecture designed to repurpose existing post-mining infrastructure for large-scale grid stabilization. This system used the Budryk Mine Shafts II and III - as the reference case, leveraging deep vertical excavations to integrate potential, pressure, and thermal energy storage. By consolidating these subsystems, the HESS provides a flexible, high-density energy reserve that supports the transition to intermittent renewable energy sources.

The system comprises three interoperable subsystems:

- Pumped Storage Hydropower (PSH): converts electricity into gravitational potential energy by transporting water between different elevations within the shaft.
- Compressed Carbon Dioxide Energy Storage (CCES): utilizes CO_2 as a working fluid in a closed-loop cycle, operating in a supercritical state to maximize energy density.
- Thermal Energy Storage (TES): an adiabatic component that captures, stores, and restores the heat of compression, eliminating the need for external fuel during the discharge phase.

Component identification and definition

The HESS architecture integrates mechanical, hydraulic, and thermal circuits managed by a centralized logic controller.

Table 4 Main components and functional roles in the integrated HESS configuration.

Diagram Label	Full Component Name	Functional Description
UR/LR	Upper and Lower Reservoirs	Hydraulic storage; UR is surface-based, while LR is situated at the shaft bottom (approx. 1157m).
G/M	Generator and Motor Units	Converters for mechanical and electrical power; specific to each subsystem (Pelton for PSH; Turbo-machines for CCES).
HPT/LPT	High-Pressure and Low-Pressure Tanks	CCES storage; HPT is a surface cluster of supercritical vessels; LPT is a shaft-based isobaric vessel (940-950m depth).
TES_H/TES_C	Hot and Cold Thermal Energy Storage	Dual-tank system utilizing basalt beds and Therminol VP-1 oil to buffer process heat.
HE1, HE2, HE3	Heat Exchangers (1, 2, and 3)	HE1 preheats CO_2; HE2 captures compression heat; HE3 provides deep cooling for LPT stability.
C/Ex	CO_2 Compressor and CO_2 Expander	Single-section turbomachinery; Compressor (Charging) and Expander (Discharging).

CO_2PUR/CO_2ST	CO_2Purification and Storage	Cryogenic purification unit and liquid storage facility for inventory replenishment and gas quality maintenance.
Energy Router	Central Control and Optimization Unit	Logic-based optimizer managing flows based on State of Charge (SOC), water levels, and real-time pressure/temperature data.

Pumped Storage Hydropower (PSH) subsystem analysis

The PSH module used Budryk II Shaft (1,157.45 m depth) to provide a storage capacity of 23.06 MWh. The system employs a vertical Pelton turbine with three control nozzles, selected for its 91% efficiency at high hydraulic heads. It is coupled to a 5.8 MW synchronous generator (6.3 kV) operating at 1,500 rpm. The system is designed for a rated flow of 0.71 m^3/s at a conservative design head of 900 m.

The module utilizes existing mine dewatering pumps (OS 100/5, OW 200/7, OWH 200/10) in a three-stage configuration:

1. Level 1,158 m to 1,050 m.
2. Level 1,050 m to 700 m.
3. Level 700 m to the surface reservoir.

The pressure pipeline (DN400) is engineered in three distinct zones to manage hydrostatic stress:

- PN40: Surface to 326 m depth.
- PN63: 326 m to 570 m depth.
- PN100: 570 m to the turbine level.

Process Stream Sequence

1. Stream I (Discharging): Water descends from the UR through the penstock to the Pelton turbine.
2. Stream II (Discharging): Effluent from the turbine is captured in the LR at the shaft bottom.
3. Stream III (Charging): The multi-stage pump system draws water from the LR.
4. Stream IV (Charging): Water is delivered back to the UR for storage.

Compressed Carbon Dioxide Energy Storage (CCES) Subsystem

The CCES subsystem operates as a closed-loop supercritical cycle between an isobaric LPT (0.64 MPa) and HPT (8.00 MPa). Using CO_2 allows for a supercritical fluid density of ~700 kg/m^3 at the high-pressure side. This results in an energy density that allows the HPT to be 58 times smaller than the LPT for the same mass of working fluid. Constant pressure is maintained in the tanks mechanically through internal membranes or pistons coupled to the LPT's movable bottom. This ensures the compressor and expander operate at peak design efficiency throughout the cycle.

- CO_2 Compressor: 10.06 MW single-section centrifugal turbomachine.
- CO_2 Expander: 10.84 MW multi-stage single-section expander.

CO_2 Process Stream Mapping In this isobaric configuration, Stream 1 and Stream 7 utilize the same physical port on the HPT, representing different phase directions.

- Charging Phase: gaseous CO_2 leaves the LPT (Stream 5), undergoes adiabatic compression in C, travels to HE2 (Stream 6) to transfer heat to the TES, and enters the HPT (Stream 7) in a supercritical state.
- Discharging Phase: CO_2 exits the HPT (Stream 1), is reheated in HE1, enters the Expander (Stream 2), passes through HE3 (Stream 3) for deep cooling, and returns to the LPT (Stream 4).

Thermal Energy Storage (TES) and heat exchange

The TES provides the system's adiabatic capability using Therminol VP-1 oil and a basalt packed-bed accumulation material.

Thermal Cycle Summary:

- Charging (Heat Capture): cold oil is drawn from TES_C via Stream B, absorbs compression heat in HE2, and is stored in TES_H via Stream C at approximately 300°C.
- Discharging (Heat Reuse): hot oil is drawn from TES_H via Stream D, preheats CO2 in HE1 before expansion, and returns to TES_C via Stream A at a return temperature of approximately 70°C.

CO_2 purification and replenishment

Purification is essential to remove moisture, mine gases (CH_4, N_2), and oxygen introduced via micro-leaks or component interaction.

Stream Definitions

- Stream E: external liquid CO_2 supply to CO_2 ST.
- Stream F: CO_2 transfer to the CO_2 PUR cryogenic unit.
- Stream G: purified gas injection into the main circuit near the LPT inlet.
- Stream H: gas recovery from the circuit back to CO2 ST for inventory management.

Purification Stages

- Filtration: removal of aerosols and solid particles.
- Dehydration: two-stage drying (pre-cooling and molecular sieve adsorption) to 10 ppmv H_2O.
- Adsorption: activated carbon removal of organic contaminants.
- Cryogenic distillation: precise separation of liquid CO2 from non-condensable trace gases (N_2, O_2, CH_4).

The following Table 5 consolidates the architectural and performance metrics for the HESS.

Table 5 Key design parameters of the PSH and CCES/TES.

Parameter	PSH Value	CCES Value
Energy Storage Capacity, MWh	23.06	32.52
Round-Trip Efficiency, %	60.01	64.75
Charging / discharging time, h	8.0 / 4.0	5.0 / 3.0

Design / storage pressure, MPa	8.2 (Inlet)	8.00 (HPT)
LPT storage volume, m³	N/A	63,300
Working fluid total mass	12,000 m³	718 t
Basalt mass (Total), t	N/A	2,426
Therminol VP-1 Mass, t	N/A	490
Storage temperature (LPT/HPT), °C	Ambient	30

Notes: CCES efficiency is calculated at the 64.75% economic setpoint. PSH capacity is based on a conservative 900 m head at Shaft II.

1.3. Description of HESS Subsystems

1.3.1. Pumped Storage Hydropower Energy Storage System

1. Charakteristics of the PSH Module

The PSH (Pumped Storage Hydropower) module is a concept for an underground energy storage system utilizing post-mining infrastructure, in particular the Budryk coal mine II shaft (KWK Budryk).

The system operates as a pumped-storage power plant, where electrical energy is stored in the form of the gravitational potential energy of water. During periods of excess electrical energy, water is pumped from the lower reservoir to the upper reservoir. During periods of increased energy demand, the water flows through a hydraulic turbine, generating electricity.

The project assumes the use of Shaft II of KWK Budryk, with a depth of approximately 1157 m and a diameter of 9 m. A lower reservoir is created in the bottom section of the shaft, while an upper reservoir is designed on the surface. The system employs a Pelton turbine coupled with a synchronous generator. This solution enables the efficient utilization of a very high hydraulic head of approximately 900–950 m.

The project envisages energy storage capacity of approximately 23 MWh, assuming a lower reservoir capacity of approximately 12,000–16,000 m³. The system can operate in daily cycles, supporting power grid stabilization and integration with renewable energy sources.

The source of mechanical energy is the flow of water from the upper reservoir to the lower reservoir through a DN400 pressure pipeline. The water drives the Pelton turbine runner, which in turn drives a 6.3 kV synchronous generator via a shaft. After passing through the turbine, the water is discharged into the lower reservoir located in the shaft, from where it is pumped back to the surface using a deep-well pumping system.

2. Basic Technological Parameters

The most important parameter of the designed PSH module is the energy storage capacity of 23.06 MWh. This value was determined based on the lower reservoir volume, hydraulic head, and hydropower unit efficiency.
The input parameters adopted for the design of the PSH module are presented in Table 6.

Table 6 Input parameters adopted for the design of the PSH module.

Parameter	Value
Total shaft depth, m	1 157.45
Shaft diameter, m	9
Lower reservoir depth, m	200
Maximum geometrically available useful head, m	950
Conservative design head adopted for calculations, m	900
Lower reservoir capacity, m^3	12 719
Operational working volume, m^3	12 000 m
Hydropower unit efficiency	0.7
Gravitational acceleration, m/s^2	9.81
Water density, kg/dm^3	1
Energy storage capacity, MWh	23.06

Based on the adopted shaft geometry and a lower-reservoir height of 200 m, the maximum geometrically available useful head was estimated at approximately 950 m. However, for the preliminary design calculations, a conservative design head of 900 m was adopted. This assumption provides an operational safety margin related to wa-ter-level fluctuations, hydraulic losses and constraints resulting from the underground in-frastructure

The energy stored in the system was determined using the following equation:

$$E = V \times \rho \times H \times g \times \eta$$

The project originally assumed an energy storage capacity of 10 MWh. However, calculations performed for the adopted shaft geometry and lower reservoir configuration indicate the possibility of achieving a storage capacity of 23.06 MWh, which is more than twice the baseline value assumed in the initial project objectives. This demonstrates that the analyzed shaft possesses a significant energy storage reserve.

In practice, filling only approximately half of the lower reservoir is sufficient to achieve the assumed 10 MWh capacity, while full utilization of the adopted reservoir volume enables the storage potential to be increased to 23.06 MWh. This parameter should therefore be regarded as one of the key advantages of the proposed solution, confirming the feasibility of using post-mining infrastructure as a large-scale energy storage facility.

The main technological parameters of the designed PSH module are summarized in Table 7.

Table 7 Main technological parameters of the PSH module.

Parameter	Value
Turbine power, MW	approx. 5.3
Generator power MW	5.8
Generator voltage, kV	6.3
Turbine type, -	Pelton, vertical
Number of nozzles, -	3
Rated flow rate, m^3/s	0.71

Pipeline diameter,	DN400
Pressure at turbine inlet, MPa	approx. 8.2
Turbine efficiency, %	approx. 91
Rotational speed, rpm	1500

The adopted technological system utilizes a very high hydraulic head combined with a relatively low water flow rate.
For this reason, a Pelton turbine was selected as the most suitable solution, due to its high efficiency under conditions of high hydraulic head and low flow rates.
The pressure pipeline was divided into three pressure zones:

- PN40 – from the surface down to a depth of approximately 326 m,
- PN63 – from 326 m to approximately 570 m,
- PN100 – from 570 m to the turbine level.

This solution enables safe operation of the installation under very high hydrostatic pressure conditions. The design incorporates expansion compensators and guide supports to reduce pipeline stresses and vibrations.

3. Operating Principle of the PSH System

The operating principle of the PSH module can be divided into two main operating modes:

Power Generation Mode

1. Water stored in the upper reservoir flows through the DN400 pipeline to the Pelton turbine.
2. The high-pressure water jet is directed through control nozzles onto the turbine runner buckets.
3. The runner drives a synchronous generator producing electrical energy.
4. After passing through the turbine, the water is discharged into the lower reservoir located in the shaft.

Pumping Mode

1. Water from the lower reservoir is pumped to higher shaft levels.
2. A deep-well pumping system transports the water stepwise up to the 700 m level.
3. The water is then conveyed via the existing mine dewatering infrastructure to the surface reservoir.
4. When energy demand increases again, the cycle is repeated.

The pumping system operates in three stages:

- level 1158 m → 1050 m,
- level 1050 m → 700 m,
- level 700 m → surface.

The total energy required to pump 12,000 m³ of water is approximately 64 MWh.

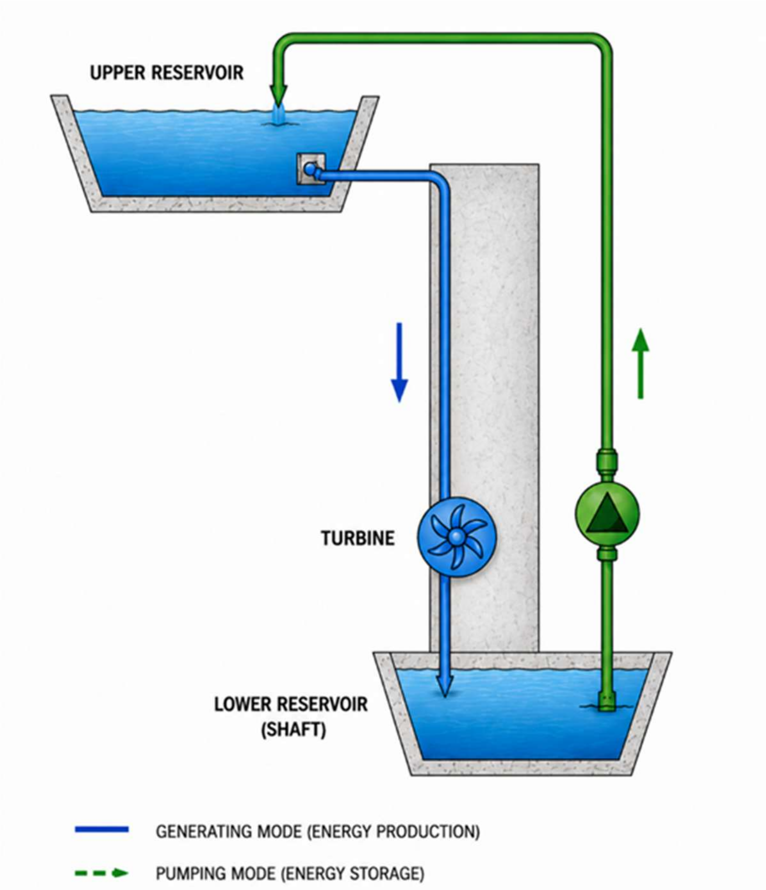

Fig. 4 Schematic diagram of PSH module operation.

4. Description and Characteristics of the Main Equipment

Pelton Turbine

The primary power generation unit is a vertical Pelton turbine equipped with control nozzles. This type of turbine belongs to the class of impulse turbines and is designed for operation under very high hydraulic head conditions. Water discharged from the nozzles at high pressure strikes the turbine runner buckets, transferring kinetic energy.

The designed hydropower unit consists of a vertical Pelton turbine directly coupled with a synchronous generator and installed inside the mine shaft. The general arrangement of the generating unit is presented in Fig. 5.

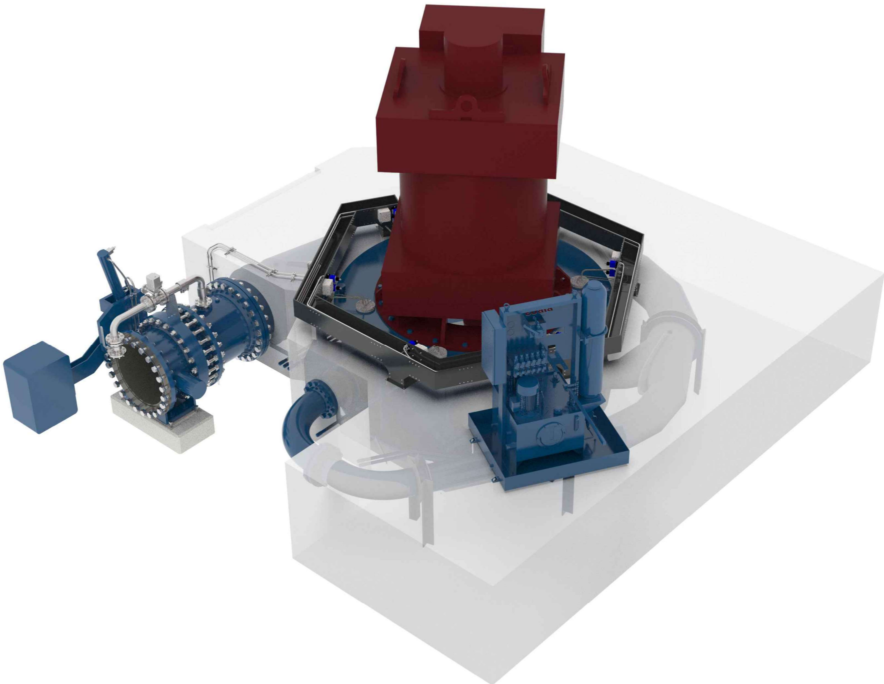

Fig. 5 Turbogenerator unit.

Main characteristics of the turbine:

- high efficiency (up to 91%),
- cavitation resistance,
- capability for smooth power regulation,
- high durability and reliability,
- ability to operate under variable load conditions.

The Pelton turbine is an optimal solution for the designed power plant located in the mine shaft, as it operates most efficiently under conditions of very high hydraulic head and relatively low flow rates, which correspond to the project requirements. Power regulation is achieved by means of needle-controlled nozzles and jet deflectors, enabling rapid flow reduction without the risk of water hammer occurrence.

The Pelton turbine runner constitutes the key rotating element responsible for converting the kinetic energy of the water jet into mechanical torque. The general view of the runner applied in the designed PSH system is shown in Fig. 6.

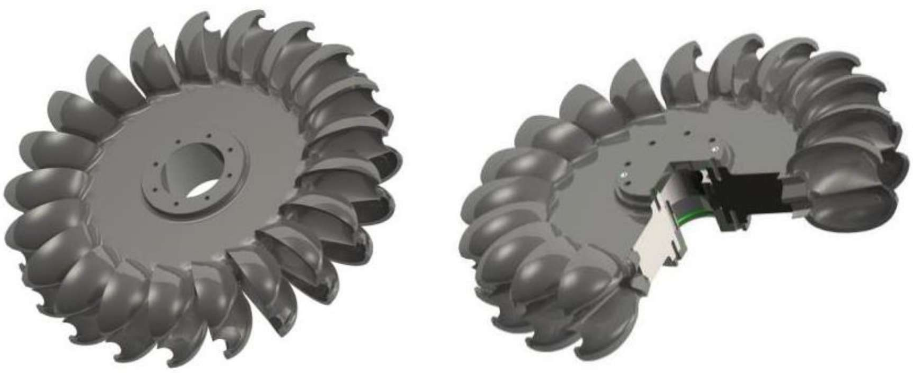

Fig. 6 Pelton turbine runner.

The runner has the form of a vertical wheel mounted on the turbine shaft. The runner diameter and the number of buckets were selected according to the design parameters and operating conditions of the hydropower unit.

The runner is made of high-strength stainless steel resistant to erosive wear. The adopted nozzle configuration ensures uniform runner loading and stable operation of the hydropower unit. The runner is characterized by high hydraulic and mechanical efficiency as well as high operational durability.

Synchronous Generator

An important issue is the selection of the hydrogenerator power rating. This value is closely related to the expected operating time and the amount of energy generated as a result of filling the lower reservoir, i.e., the energy storage capacity.

Table 8 presents the power ratings as a function of the expected operating time and the energy storage capacity.

Table 8 Operating parameters of the PSH module.

Energy storage capacity [MWh]	Operating time [h]	Turbine power [MWh]	Water flow rate [m^3/s]
23.06	2	11.5	1.77
	3	7.7	1.18
	4	**5.8**	**0.88**
	5	4.6	0.71
	6	3.8	0.59
	7	3.3	0.50
	8	2.9	0.44
	9	2.6	0.39
	10	2.3	0.35

The synchronous generator is directly coupled to the turbine. Its rated power is approximately 5.8 MW, with an operating voltage of 6.3 kV. The generator operates synchronously with the power grid and is equipped with an automatic voltage regulation system.
Main characteristics of the generator:

- rotational speed: 1,500 rpm,
- IC81W cooling system,
- F/B insulation class,
- capability for parallel operation with the grid,
- overload and differential protection systems.

Pressure Pipeline (Penstock)

The DN400 pipeline conveys water from the upper reservoir to the turbine. It is made of high-strength steel and divided into pressure zones. The structure includes:

- support structures,
- guide supports,
- expansion compensators,
- a manifold supplying water to the nozzles,
- a shut-off ball valve.

In the lower section, the pipeline operates at pressures reaching up to 10 MPa.

Pumping System

The existing mine dewatering infrastructure is utilized for water transport. The system incorporates the following pumps:

- OS 100/5,
- OW 200/7,
- OWH 200/10.

The pumps operate in stages and enable water transport from the lower reservoir to the surface. The use of existing pumping stations significantly reduces the scope of required modifications to the mining infrastructure.

Surface Reservoir

An important component of the PSH module is the surface reservoir, which serves as the upper water storage facility. The reservoir is designed as an open structure, partially embedded into the terrain, thereby reducing its environmental impact and improving operational safety.

During power generation mode, the reservoir acts as the water source supplying the turbine, while during pumping mode it stores water pumped from the lower shaft reservoir.

The reservoir capacity was selected to ensure cooperation with the lower water storage facility having a capacity of approximately 12,700 m³. The reservoir is equipped with an overflow system, shut-off valves, and a water level monitoring system.

Service Platform and Auxiliary Infrastructure

A service platform is planned in the shaft head area to provide safe access to the technological equipment and enable operation and maintenance activities. The platform will be equipped with safety railings, a lighting installation, and power and control connections.

Access to the hydropower unit installed at the turbine level will be provided by ladders and the shaft hoisting system. During maintenance works, transportation of personnel and technical equipment to the powerhouse level will be possible.

This solution enables periodic inspections and ongoing maintenance of the PSH system.

5. Summary

The PSH module utilizing a mine shaft represents a modern and promising energy storage solution. The project confirms the feasibility of adapting post-mining infrastructure for energy purposes while simultaneously reducing investment costs and environmental impact.

The application of a Pelton turbine, a synchronous generator, and the existing mine pumping system enables high system efficiency and stable operation under conditions of very high hydraulic head. The proposed system may become an important component supporting the energy transition and the development of renewable energy sources.

1.3.2. Adiabatic Compressed Air Energy Storage System and Thermal Energy Storage System

1. Characteristics of A-CAES/TES

The analysed energy storage system is an adiabatic compressed air energy storage (A-CAES) system, designed to make use of the infrastructure of a decommissioned Budryk hard coal mine: mining shaft no. III with a diameter of 9 meters and a depth of 1089 meters.

The core idea of the solution is to employ the post-mining shaft as a pressure vessel for compressed air and to install along its vertical axis a high-temperature thermal energy storage (TES) with a basalt packed-bed material – owing to which the mechanical energy of compressed air and the thermal energy of compression are stored in a single, common location. The system operates in a daily cycle: during the charging phase, the compressor draws energy from the grid during periods of low electricity prices, placing compressed air in the shaft and the compression heat in the TES; during the discharging phase, the air preheated in the TES is directed to the expander coupled with the generator, returning the stored energy to the grid. Locating the system within the post-mining infrastructure allows the existing shaft, surface buildings, and electrical grid connection to be reused, significantly reducing capital expenditure compared to greenfield development. The surrounding rock mass provides natural mechanical stability of the vessel and stabilises the thermal conditions of the low-temperature storage.

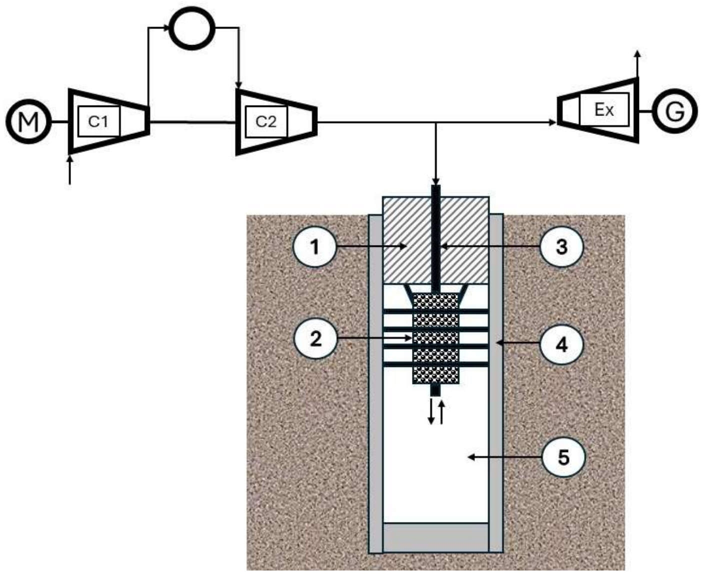

Fig. 7 Mine shaft utilization diagram: 1 – shaft sealing, 2 – TES tank, 3 – compressed air inlet/outlet pipe; 4 - shaft casing, 5 – compressed air reservoir.

2. Basic Technological Parameters

Table 9 Assumptions for A-CAES modelling.

Parameters	Value
Air storage temperature, °C	30
Air compression temperature, °C	500
Charging time, h	5
Discharging time, h	3
Isentropic efficiency – compressor, -	0.80
Isentropic efficiency – expander, -	0.80
Electromechanical efficiency, -	0.98
Ambient pressure, kPa	101.325
Ambient temperature, °C	20
Air storage pressure (min), MPa	3.6
Air storage pressure (max), MPa	5.0
Air pressure drop on heat exchanger, %	10
Plug diameter, m	9.0
Mine shaft diameter	9.0
Design pressure (lower face), MPa	5.1
Max. pressure for full-height calculation, MPa	8.0
Packed bed porosity, %	38.0
Additional TES volume, %	20.0
Basalt particles diameter, m	0.016
Basalt particles density, kg/m^3	2 768
Air temperature drop (discharging stage), %	10.0

The parameters compiled in the table correspond to the reference variant of the analysed adiabatic compressed air energy storage (A-CAES) system, in which the mechanical energy of compressed air and the thermal energy of compression are stored in a post-mining shaft serving as the pressure vessel.

The machinery side of the system comprises a two-section compressor with a total mean electric power of 33 MW and a single-section expander with a mean electric power of 36 MW. The asymmetry of the power outputs is characteristic of A-CAES systems with non-symmetric charging and discharging operating times – the higher expander power results from the shorter duration of the discharging phase and from the utilisation of the compression heat stored in the TES, which increases the inlet enthalpy of the air delivered to the expander. Atmospheric air is drawn in at reference conditions of 20°C / 101.325 kPa and compressed to the storage pressure of 5.0 MPa, which corresponds to an overall pressure ratio of approximately 50. The split between the low-pressure section (C1) and the high-pressure section (C2) has been selected such that the C1 outlet temperature is 155°C at a pressure of 0.4 MPa, and after cooling in the intercooler to 30°C, the air is compressed in C2 with the possibility of reaching an outlet temperature of up to 500°C – a value resulting from the balance between the maximum temperature safe for the structural materials of the rotor and the target charging temperature of the TES bed.

The upper high-pressure barrier of the storage vessel is provided by a reinforced-concrete shaft plug with a diameter of 9.0 m (matched to the internal diameter of the shaft) and a height of 100 m in the analysed variant, designed for a design pressure of 5.1 MPa, corresponding to the maximum storage pressure increased by a safety margin. The maximum height of the plug has been calculated for an in-shaft pressure of 8.0 MPa.

Table 10 TES and packed bed parameters.

Parameters	Value
TES internal diameter, m	5.0
TES segment height, m	10.0
Total length of segments (recommended), m	40.0
Particles diameter (packed bed), mm	16
Bed material density (basalt), kg/m³	2 768
Bed material specific heat (basalt), J/(kg·K)	970
Bed porosity	0.38
Total basalt mass, t	1 347
Material thermal resistance (basalt), °C	> 800
Maximum bed temperature, °C	500
Minimum bed temperature, °C	30

The thermal energy storage is designed as a segmented, column-type structure located inside the shaft. Each segment is a vertical cylindrical steel vessel with an internal diameter of 5.0 m and a height of 10.0 m; in the recommended variant, the total length of the segments amounts to 40.0 m. The storage bed material is basalt aggregate with a mean grain size of 16 mm, a density of 2 768 kg/m3, a specific heat capacity of 970 J/(kg·K) and a bed porosity of 0.38 – parameters established on the basis of literature analyses and experimental investigations. The choice of basalt results from the combination of high volumetric heat capacity, confirmed thermal resistance exceeding 800°C, low thermal expansion, and low cost owing to the widespread availability of this material. The bed operating temperature range is 30-500°C – the minimum corresponds to the temperature of the air stored in the shaft, and the maximum is identical with the outlet temperature of the C2 compressor section.

3. Description and Characteristics of the Main Equipment

Air compressor

The compressor is the charging machine of the underground compressed-air storage. Its task is to draw atmospheric air through a filtered air intake, compress it to a storage pressure of approximately 5 MPa, and direct it to the mining shaft, in which the mechanical energy is stored as the energy of compressed air, while the compression heat flow is stored in a high-temperature TES (basalt accumulation bed). Due to the required high overall pressure ratio (≈ 50) and the need to maintain the air temperature within a range safe for the structural materials of the rotor and casing, the compressor is designed as a two-section (two-stage) centrifugal turbomachine, multi-stage within each section, driven by an electric motor. The total average electric power at the motor terminals is 33 MW. Atmospheric air at parameters of 20°C / 101.325 kPa is drawn in through the air intake equipped with filter mats and fed to the low-pressure section (C1), in which it is polytropically compressed to approximately 0.4 MPa and to a mean temperature of about 155°C. From the outlet of section C1, the working medium is directed to the intersection heat exchanger (intercooler), where it is cooled to a temperature close to ambient (approximately 30°C). The cooled air, dried in the condensate separator, then enters the high-pressure section (C2), where it is compressed to a storage pressure of approximately 5 MPa and reaches an outlet temperature of up to 500°C (a value limited by the selection of the HP section pressure ratio – determined by the requirement of thermal safety and the target charging temperature of the TES bed).

Air expander

Compressed, preheated air from the thermal energy storage is directed to the expander. The system concept employs a single-section expander (single-stage from a technological standpoint – without inter-stage air reheating). This follows from the assumption that all the heat required for expansion is supplied from a single high-temperature source – the TES bed – with no need for inter-stage reheating chambers such as those found in classical diabatic configurations with a two-section expander (Huntorf, McIntosh). Structurally, the expander is based on a converted low-temperature condensing or extraction–back-pressure steam turbine, adapted for operation with air as the working medium. This approach is standard in the CAES industry – the expanders at Huntorf and McIntosh are converted steam turbines, and it is a technological pathway validated by several decades of commercial operation. In the analysed variant, the mean expander power is 36 MW.

Heat exchanger

Its task is to partially recover the heat generated during air compression in section C1 and transfer it to an intermediate heat storage, to support another technological process, or to a local district-heating system. The exchanger, of shell-and-tube design, is sized for the lowest air temperature downstream of the first compressor section – corresponding to the minimum pressure ratio during the charging cycle – and for a constant mass flow rate of water or another heat-transfer fluid, so as to ensure the required outlet fluid temperature at every instant of the charging phase. As the storage pressure rises, the air temperature downstream of section C1 increases, while the thermal duty of the exchanger may exhibit a slight decreasing trend at high pressure ratios.

Thermal Energy Storage

The storage unit is designed as a segmented, column-type structure located along the axis of the shaft. Each segment is a vertical cylindrical steel vessel with an internal diameter of 5 metres and a height of 10 metres. In the recommended variant, the total length of the segments amounts to 40 metres. Each segment is equipped with a lower grate bottom, an inspection nozzle in the shell, a service platform, and stiffening rings (increasing the shell rigidity under the elevated pressure differential occurring during discharge). The first (uppermost) segment is fitted with an upper head featuring the compressed-air inlet nozzle; the last (lowermost) segment is equipped with a profiled condensate-catcher hood with a condensate discharge pipeline routed to an above-ground tank, drained automatically by pressure differential. Service ladders run between the platforms. The segments are stacked one on top of another and connected by DN5000 axial bellows expansion joints, which compensate for thermal elongation. Each segment rests on a support ring fitted with mounting lugs and is suspended by tubular tie rods (with upper and lower pins providing articulation, which eliminates the introduction of secondary loads into the support structure) from the main steel structure anchored to the shaft footings. A double wall filled with mineral wool is provided in the area of the support ring.

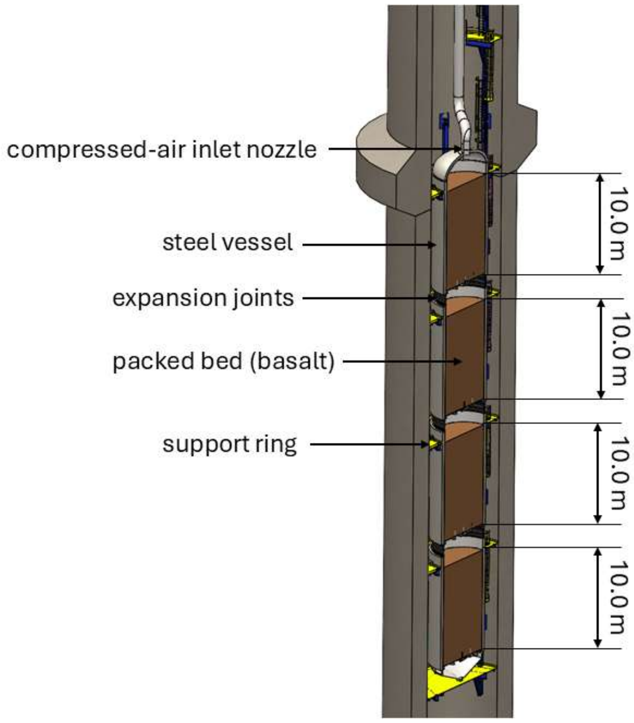

Fig. 8 TES tank visualization [1].

On the basis of the literature analyses and experimental investigations carried out, it was decided that basalt aggregate with a natural mean fraction of 16 mm, a density of 2768 kg/m^3, a specific heat capacity of 970 J/(kg·K) and a bed porosity of 0.38 would be used as the storage bed material. The choice of basalt results from the combination of high volumetric heat capacity, confirmed thermal resistance up to >800°C, low thermal expansion, and low cost owing to the widespread availability of this material. The maximum bed temperature is Tmax = 500°C, and the minimum is Tmin = 30°C (the temperature of the air stored in the shaft).

Shaft sealing

The shaft plug constitutes the high-pressure upper barrier of the storage vessel. Its role is the gas-tight closure of the active volume of the post-mining shaft (which functions as a pressure vessel for compressed air) and the transfer of the weight of the TES assembly together with its support structure suspended within it. The plug operates under a pressure differential ranging from atmospheric on the upper side up to 5.1 MPa on the lower side (the adopted design pressure corresponds to the maximum storage pressure increased by a safety margin). The plug is designed as a monolithic, cylindrical reinforced-concrete element, with a diameter matched to the internal diameter of the shaft (9.0 m) and a height H = 100 m, made of C30/37 class concrete with dispersed reinforcement, the role of which is to carry the internal tensile

[1] Waniczek S., *System magazynowania energii w sprężonym powietrzu sprofilowany na potrzeby dużych jednostek wytwórczych*. Rozprawa doktorska, Gliwice 2023.

stresses arising from the deformation of the body under pressure action. The maximum height of the shaft plug was calculated for an in-shaft pressure of 8.0 MPa, which means that for the variant considered the actual length of this element will be lower.

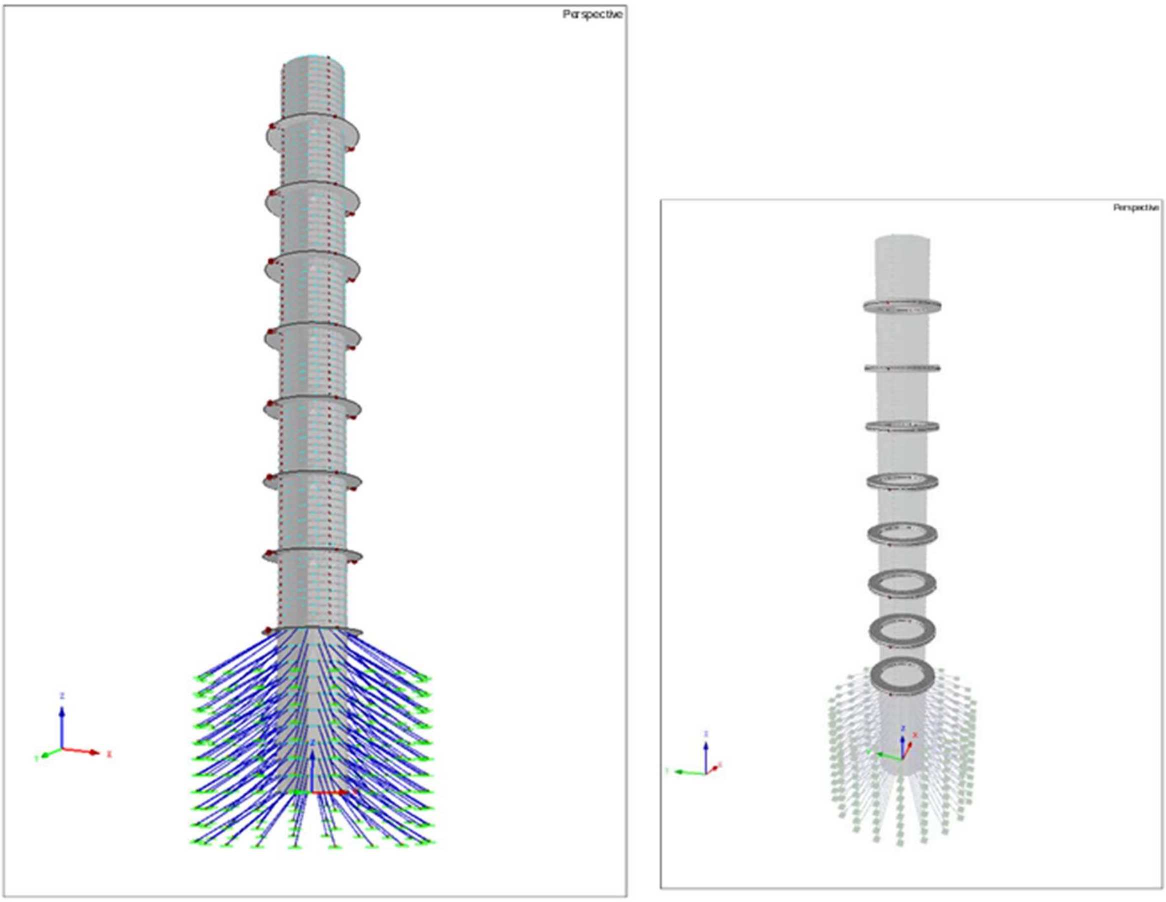

Fig. 9 Shaft plug visualization [1].

Anchorage of the plug in the rock mass has been implemented in two stages:

- 220 ground anchors in the lower 20-metre section of the plug, made of S355 steel, of 12 m length and 100 mm diameter, fully fixed in the host rock. The anchors transfer axial force only;

- 8 thrust footings distributed around the circumference of the plug, executed as reinforced-concrete rings of 2.0 m thickness and 1.0 m height, set in rock recesses, providing additional stabilisation and transfer of the loads from the TES support structure. The bearing of the footings in the rock mass is modelled as elastic.

The lowest thrust footing additionally serves as the shaft footing for the TES assembly – the main steel structure, from which the storage segments are suspended (with a total mass of the TES assembly of the order of 5000 t), is hung from it by means of six HEM 460 load-bearing profiles.

1.3.3. Compressed Carbon Dioxide Energy Storage (CCES)

1. Characteristics of CCES

The analysed energy storage system is a compressed carbon dioxide energy storage (CCES) system with isobaric low-pressure and high-pressure tanks, designed to make use of the infrastructure of a decommissioned hard-coal mine Budryk hard coal mine: mining shaft no. III with a diameter of 9 meters and a depth of 1089 meters.The core idea of the solution is to employ the post-mining shaft as an underground isobaric low-pressure tank (LPT) for carbon dioxide, while an isobaric high-pressure tank (HPT) and a high-temperature thermal energy storage (TES) are installed on the surface. The TES is designed as a two-tank system - a hot tank (TES_h) and a cold tank (TES_c) – in which Therminol VP-1 synthetic thermal oil serves as the heat transfer fluid circulating between the tanks and the CO_2 heat exchangers (HE1, HE2), while a basalt packed bed acts as the accumulation material inside each tank.

The system operates in a daily cycle: during the charging phase, the compressor draws energy from the grid during periods of low electricity prices, compressing CO_2 from the LPT to the supercritical HPT and storing the compression heat in the TES; during the discharging phase, the CO_2 preheated in the TES is directed to the expander coupled with the generator, returning the stored energy to the grid. The additional heat exchanger (HE3) serves as a component that integrates the energy storage system with a potential local district heating system or other energy storage components. It ensures that the carbon dioxide is deeply cooled to the storage temperature in the tank. The use of carbon dioxide instead of air enables a significantly higher energy storage density, owing to operation on the high-pressure side in the supercritical state. Locating the system within the post-mining infrastructure allows the existing shaft, surface buildings, and electrical grid connection to be reused, significantly reducing capital expenditure compared to greenfield development of an above-ground storage facility with a volume of the order of tens of thousands of cubic metres. The surrounding rock mass provides natural mechanical stability of the low-pressure vessel and stabilises its thermal conditions.

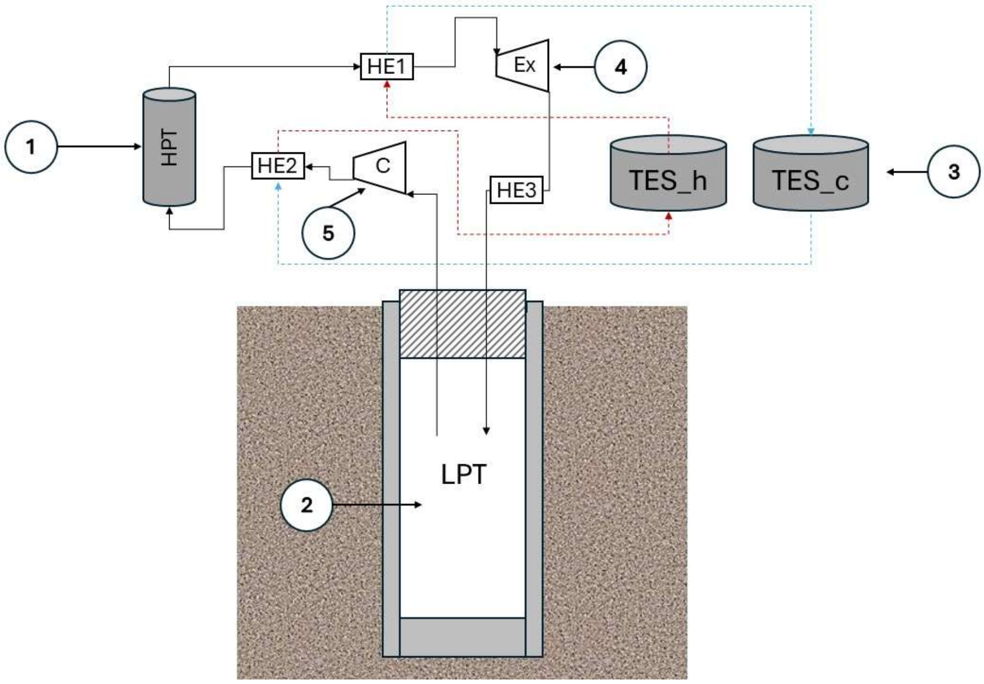

Fig. 10 The CCES scheme: 1 - high-pressure vessel; 2 - low-pressure vessel; 3 – TES tanks; 4 – carbon dioxide expander; 5 – carbon dioxide compressor.

2. Basic Technological Parameters

Table 11 Assumptions for CCES modelling.

Parameters	Value
CO_2 storage temperature (LPT and HPT), °C	30
CO_2 compression temperature, °C	300
Charging time, h	5
Discharging time, h	3
Isentropic efficiency – compressor, -	0.80
Isentropic efficiency – expander, -	0.80
Electromechanical efficiency, -	0.98
TES energy efficiency, -	0.95
Inlet pressure (from LPT), MPa	0.64
Outlet pressure (to HPT), MPa	8.00

The parameters compiled in the table correspond to the reference variant of the analysed compressed carbon dioxide energy storage (CCES) system, operating between a low-pressure tank (LPT) at 0.64 MPa and a high-pressure tank (HPT) at 8.00 MPa, with a CO_2 storage temperature of 30°C in both vessels. At HPT conditions, carbon dioxide is in the supercritical state – above the critical point of 7.38 MPa and 31.1°C which yields a fluid density of approximately 700 kg/m^3 and enables storage of a given CO_2 mass in a volume approximately 58 times smaller than the corresponding LPT volume at the same temperature.

The machinery side of the system comprises a single-section CO_2 compressor with a mean electric power of ≈ 10.06 MW and a single-section expander with a mean electric power of ≈ 10.84 MW.

The system operates in a daily cycle: during the 5-hour charging phase, the compressor draws 50.31 MWh of electric energy from the grid, compressing 39.88 kg/s of CO_2 from the LPT to the HPT; the compression heat is transferred from the CO_2 to the Therminol VP-1 circuit in a dedicated shell-and-tube heat exchanger and subsequently stored in the hot TES tank. During the 3-hour discharging phase, Therminol VP-1 from the hot tank is circulated through the heat exchanger, where it preheats the CO_2 leaving the HPT before it enters the expander; the cooled oil then returns to the cold TES tank. The expander operates at a CO_2 mass flow rate of 66.46 kg/s, producing 32.51 MWh of electric energy. The two-to-one ratio of the discharging to charging mass flow rate follows directly from the ratio of the phase durations, with the total CO_2 mass in the closed circuit remaining constant at approximately 718 t. Both the LPT and HPT operate isobarically throughout the full cycle, which eliminates the need for throttling valves and ensures that both machines operate at or near their design point at all times, maximising conversion efficiency.

Table 12 Thermal Energy Storage parameters.

Heat transfer fluid	Therminol VP-1 synthetic thermal oil
Volume per TES tank, m^3	707
Basalt mass per tank, t	1 213
Total basalt mass (both tanks), t	2 426
Total Therminol VP-1 mass, t	490
Particles diameter (packed bed), mm	16
Bed material density (basalt), kg/m^3	2 768
Bed material specific heat (basalt), J/(kg·K)	970
Bed porosity, -	0.38
Material thermal resistance (basalt), °C	> 800
Maximum bed temperature, °C	500
Minimum bed temperature, °C	30

The low-pressure vessel is realised as a post-mining shaft with an internal diameter of 9.0 m, requiring a net storage volume of ≈ 63 300 m3 and a corresponding shaft depth of approximately 940-950 m. The high-pressure vessel, by contrast, requires only 1 023 m3. That may be accommodated by a cluster of above-ground high-pressure cylinders. The thermal energy storage is designed as a two-tank system – a hot tank and a cold tank in which Therminol VP-1 synthetic thermal oil (operating range 12-400°C) circulates between the tanks and the CO2 heat exchanger, while a basalt packed bed (≈ 1 213 t per tank, total ≈ 2 426 t) acts as the primary accumulation material inside each tank. The total inventory of Therminol VP-1 in the system amounts to approximately 490 t, filling the pore space of the packed bed (porosity ε = 0.38) and the associated pipework and heat exchangers. Each TES tank has a net volume of 707 m3, corresponding to a height of approximately 36 m at an internal diameter of 5.0 m.

3. Description and Characteristics of the Main Equipment

CO_2 compressor

The compressor is the charging machine of the CCES system. Its task is to draw carbon dioxide from the isobaric low-pressure tank (LPT), compress it from a storage pressure of 0.64 MPa to a storage pressure of 8.00 MPa, and direct it, after heat exchange in the dedicated CO_2/Therminol VP-1 heat exchanger and subsequent end-cooling, to the isobaric high-pressure tank (HPT). Due to the moderate overall pressure ratio and, critically, the requirement to preserve the full thermal potential of the compression process for storage in the TES, the compressor is designed as a single-section centrifugal turbomachine. The absence of inter-stage cooling is intentional. Carbon dioxide at parameters of 0.64 MPa / 30°C is drawn from the LPT and compressed adiabatically to 8.00 MPa, reaching an outlet temperature of approximately 315-330°C. The mean electric power at the motor terminals is 10.06 MW, the CO_2 mass flow rate during charging is 39.88 kg/s, and the total electric energy consumed per daily charging cycle amounts to 50.31 MWh. At the outlet pressure of 8.00 MPa – above the CO_2 critical pressure of 7.38 MPa – the compressed carbon dioxide is in the supercritical state, with a density of approximately 700 kg/m^3.

CO_2 expander

The expander is the discharging machine of the system. It receives carbon dioxide from the HPT, preheated in the CO2/Therminol VP-1 heat exchanger to approximately 300°C, and converts its thermal and mechanical energy into shaft work, which is transmitted via a flexible coupling and speed-reducing gearbox to the electric generator. The system concept employs a single-section expander, multi-stage in the aerodynamic sense, without inter-stage reheating. The mean electric power at the generator terminals is 10.84 MW, the CO_2 mass flow rate during discharging is 66.46 kg/s – a two-to-one ratio relative to the charging mass flow rate, resulting directly from the 4-hour discharging phase duration against the 8-hour charging phase at equal total CO2 mass – and the total electric energy produced per daily discharging cycle amounts to 32.51 MWh. Both the LPT and HPT are isobaric, so the expander operates at constant inlet and outlet conditions throughout the full discharging phase.

Low-pressure CO_2 tank – LPT (underground, post-mining shaft)

The LPT stores the full CO2 inventory of the system at low pressure when the system is in the discharged state and provides the suction medium for the compressor during the charging phase. The LPT is realised by adapting a decommissioned post-mining shaft, with an internal diameter of 9.0 m, to the function of an isobaric underground pressure vessel. The storage pressure of 0.64 MPa and the storage temperature of 30°C correspond to the sub-critical gaseous state of CO_2, at which the density is approximately 12 kg/m^3; the resulting required net storage volume is ≈ 63 300 m^3, corresponding to a shaft depth of approximately 940-950 m.

High-pressure CO_2 tank – HPT (above-ground, isobaric)

The HPT stores the full CO2 inventory of the system at high pressure when the system is in the charged state and provides the supply medium for the expander during the discharging phase. The storage pressure of 8.00 MPa and the storage temperature of 30°C place carbon dioxide in the supercritical state, where its density reaches approximately 700 kg/m^3; the resulting required net storage volume is 1 023 m^3 – approximately 58 times smaller than the corresponding LPT volume for the same CO2 mass. This volume is accommodated by a cluster of above-ground high-pressure cylindrical vessels of industrial design. Constant (isobaric) pressure is maintained mechanically, by means of pistons or internal membranes coupled to the LPT movable bottom, so that any change in the CO_2 volume stored in the HPT is automatically compensated by an equal and opposite change in the LPT storage volume, without any external regulation or energy expenditure. The HPT vessels are preferably installed in below-grade chambers or wells, where the ambient temperature is stable and independent of seasonal variation, which limits unintended pressure fluctuations caused by thermal expansion of the stored CO_2.

Thermal energy storage – TES (two-tank packed-bed system)

The TES is the element that gives the system its adiabatic character, preserving the compression heat generated during the charging phase and returning it to the CO_2 circuit in the discharging phase. The TES is designed as a two-tank system comprising a hot tank maintained at approximately 300°C and a cold tank maintained at approximately 70°C. The heat transfer fluid circulating between the tanks and the CO_2 heat exchanger is Therminol VP-1 with an optimum operating range of 12-400°C. The accumulation material filling each tank is a basalt packed bed. The combination of basalt packed bed and Therminol VP-1 yields an effective volumetric heat capacity of approximately 2.35 MJ/($m^3 \cdot K$); for the temperature swing of 230 K, this corresponds to an energy density of approximately 150 kWh/m^3 and a net volume of 707 m^3 per tank (nominally 780 m^3 with a 10% construction margin). Total basalt inventory amounts to approximately 2 426 t (1 213 t per tank) and the total Therminol VP-1 inventory to approximately 490 t, filling the pore space of both packed beds together with the associated pipework and heat exchangers.

CO_2/Therminol VP-1 heat exchangers

Heat exchange between the CO_2 circuit and the Therminol VP-1 circuit takes place in dedicated shell-and-tube heat exchangers of counter-flow design, rated for the full high-side CO_2 pressure of 8.00 MPa. Two separate heat exchangers are provided: one on the charging side, located between the compressor outlet and the HPT inlet, in which hot compressed CO_2 (315-330°C) transfers its compression heat to cold Therminol VP-1 drawn from the cold TES tank, cooling the CO_2 to approximately 70°C before it is directed to the end cooler and the HPT; and one on the discharging side, located between the HPT outlet and the expander inlet, in which hot Therminol VP-1 drawn from the hot TES tank preheats the supercritical CO_2 leaving the HPT from 30°C to approximately 300°C before expansion. Three-way regulating valves on the Therminol VP-1 side, together with a bypass on the CO_2 side, enable precise control of the CO_2 temperature at the heat exchanger outlets in both operating modes.

1.3.4. Purification of carbon dioxide unit used in CCES

The use of appropriate concrete SIKAGARD coatings should ensure sufficient carbon dioxide tightness of tanks, as gas diffusion through concrete is highly limited. However during long-term operation of a CCES system, small amounts of impurities may appear in the CO_2 circuit, resulting from factors such as the interaction of the working fluid with system components, the presence of moisture, mine gases, and micro-leaks in the system. Trace amounts of water vapor, oxygen, methane, nitrogen, and particulate matter may be present in the CO_2 stream, which can cause corrosion, reduced heat transfer, and increased equipment wear (Table 13).

Table 13 Assumed inlet gas parameters.

Parameter	Value
Pressure, bar	1,4
Temperature, ºC	70
CO_2 content, %	99,04
H_2O content, %	0,69
CH_4 content, %	0,10
N_2 content, ppm	750
NO content, ppm	15
O_2 content, ppm	750
Other, ppm	Other

To maintain high working fluid purity and stable operating parameters, cryogenic CO_2 purification was implemented. This technology, based on condensation and low-temperature separation of gas mixture components, enables the effective removal of non-condensable gases and achieves CO_2 purity above 99.99%. This solution reduces working fluid losses, improves the system's reliability and efficiency, and can be integrated with liquid CO_2 storage infrastructure.

General technical and technological concept of the carbon dioxide purification system

The technical and technological concept of the carbon dioxide purification system was adapted to a process gas stream of 1000 kg/h of carbon dioxide, containing gaseous contaminants and moisture. The assumed liquid CO_2 storage capacity was 100 tons.

A simplified diagram of the purification installation is shown at Fig. 11.

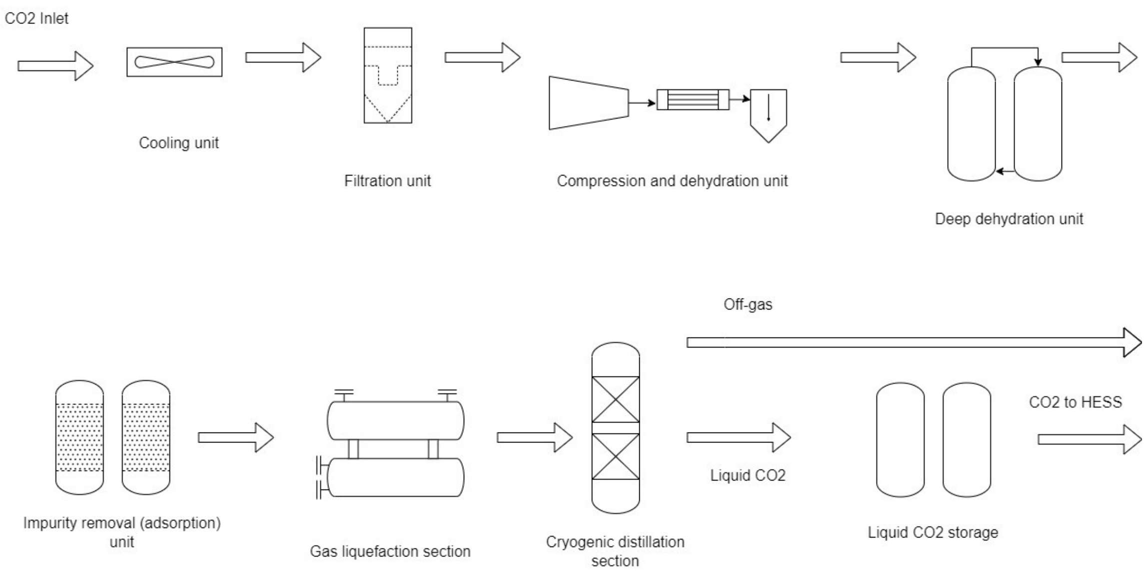

Fig. 11 Simplified diagram of carbon dioxide purification installation.

Before the carbon dioxide stream is directed to the proper purification process, after cooling to a temperature of approximately 40°C, a filtration stage is planned to remove solid particles, aerosols, and mechanical impurities that may originate from both the process system and the underground storage space. A filter capable of separating fine liquid droplets and small solid particles will be used for this purpose. Pre-filtration is crucial for protecting downstream system components, particularly the compressor, heat exchangers, and adsorption units. The presence of solid contaminants could lead to accelerated wear of the compressor's moving parts, clogging of the adsorption beds, and reduced efficiency of the gas drying and purification processes. Implementing this stage therefore increases the system's operational reliability and the durability of key technological equipment.

After filtration, the CO_2 stream will be directed to a pre-cooling section, which will lower the gas temperature prior to compression. Cooling will be accomplished in a gas cooler using cooling water. The CO_2 stream will then be directed to the compression section. Gas compression will be achieved in a two-stage CO_2 compressor, which raises the gas stream pressure to approximately 20 bar, corresponding to the pressure required for liquid CO_2 storage. The compression system will be equipped with an intercooler, an aftercooler, and a condensate separator to remove moisture condensed during gas compression and cooling. Heat from the compressor and coolers will be collected using a cooling water circuit.

After compression, the CO_2 stream will be directed to the deep dehydration section, which will utilize an molecular sieve adsorption system with temperature swing regeneration. The system will operate in a two-column configuration, where one column is in dehydration mode while the other is undergoing bed regeneration. This design enables continuous system operation and ensures stable gas quality parameters. As a result of the dehydration process, the moisture content in the CO_2 stream will be reduced to approximately 10 ppmv H_2O. This is important for subsequent stages of the technological process, particularly CO_2 condensation and cryogenic distillation, where the presence of moisture could lead to freezing, hydrate formation, equipment malfunctions, and reduced separation efficiency.

The carbon dioxide stream will then be directed to the organic contaminant adsorption section. This section contains an adsorber module filled with activated carbon, designed to remove trace organic compounds present in the CO_2 stream. The maximum concentration of organic contaminants at the inlet to the adsorption section is assumed to be 10 ppm. The adsorber will use activated carbon with high sorption capacity, ensuring effective capture of identified organic compounds and obtaining the required gas quality before it is directed to the next stages of the technological process. A final filter is planned at the outlet of the adsorber battery to retain fine particulate matter, particularly coal dust that may originate from the adsorbent bed. This solution protects downstream equipment from particulate contamination and ensures the purity of the CO_2 stream sent for further processing.

The purified gas will then be directed to the CO_2 liquefaction section, where carbon dioxide is condensed by lowering the temperature. At this stage, any non-condensable gases, such as CH_4, N_2, O_2, or NO, remain in the gaseous phase and are discharged as a vent stream. Heat from the refrigeration system will be extracted using a cooling water circuit. The liquefied CO_2 may contain physically dissolved trace amounts of gases, such as CH_4, N_2, O_2, or NO. These traces will be removed in the cryogenic distillation section, where liquid carbon dioxide is fed via a liquid CO_2 pump. The pump ensures a stable feed pressure to the distillation column, ensuring the proper operation of the separation process.

After the distillation process, the purified CO_2 will be directed to a battery of cryogenic tanks, which will serve as storage for the working fluid for the plant. In practice, it is possible to use storage tanks also used for gas replenishment in the technological process. The liquid CO_2 storage facility should be capable of storing approximately 100 tons of CO_2. In the analyzed concept, the storage facility consists of two cryogenic tanks, each with a capacity of approximately 50 tons of CO_2. Because cryogenic tanks have an evaporation rate of approximately 0.4-2.0% of their volume per day, depending on the tank design and ambient conditions, the facility can optionally be equipped with a system for re-liquefying the evaporated CO_2, reducing losses of the working fluid and improving the efficiency of the storage system.

Description of the Main Process Units

The proposed process units are designed for a capacity of 1000 kg/h. The units should be equipped with control systems and appropriate frequency converters for the motors and electric heaters to ensure regulation within a range of 30-100% of the nominal capacity.

<u>CO_2 stream acquisition</u>

The CO_2 stream will be acquired from an energy storage system in the mine shaft. A portion of the gas stream from the main process will be directed to the purification system. The feed gas flow rate is set at 1000 kg/h, which corresponds to a volumetric flow of approximately 550 Nm^3/h.

<u>Filtration</u>

A cooled CO_2 stream at approximately 40°C will be filtered to remove particulate matter, aerosols, and mechanical impurities originating from the system or underground storage space. The filter will separate fine liquid droplets and solid particles.

<u>Gas stream dehydration</u>

Gas dehydration will be performed in two stages. The first stage involves cooling the flowing stream to a temperature of 5°C in the pre-cooling section. The resulting condensate will be collected in an integrated separator and directed to wastewater. This stage will allow for preliminary drying of the gas and protect the CO_2 compressor from operating on wet gas.

Deep gas drying will be achieved in an adsorption dryer with temperature-controlled bed regeneration. Due to the required low final gas humidity, the dryer should be appropriately oversized. The higher nominal flow rate of the device compared to the design value results from the need to ensure the appropriate amount of active adsorption bed necessary to achieve the required degree of drying.

An alternative solution could be the use of a pressure swing adsorber with a purge. However, it should be noted that this type of system is associated with gas losses of approximately 3–5% of the flow due to the bed regeneration process.

<u>CO_2 compression</u>

The dehydrated CO_2 stream will be compressed to 20 bar in a two-stage compressor in an explosion-proof design. The compressor should be equipped with gas filters, coolers, cyclone condensate separators, and an inverter. Condensate from the compressor module will be directed to the wastewater stream.

<u>CO_2 purification</u>

The CO_2 stream will be purified in two stages. Adsorption of possible organic contaminants will take place in the adsorption section in apparatuses filled with activated carbon. The selected apparatus assumed a content of adsorbable hydrocarbons of 10 ppm.

The second purification stage is cryogenic distillation in a column, which separates liquid CO_2 from the gases dissolved in the liquid. The distillate will be collected from the bottom of the column and should meet the quality requirements for raw gas. The gas containing concentrated contaminants will be collected from the top of the column and directed to the emitter.

<u>CO_2 liquefaction</u>

The carbon dioxide stream will be condensed in a unit adapted for CO_2 liquefaction in the process line. The liquefaction system is equipped with a compressor, a regenerative heat exchanger, a water condenser, a cooler, and a buffer tank. Heat is extracted by cooling water. The unit's power consumption is estimated at 70 kW.

<u>CO_2 stream storage</u>

The liquefied product will be stored in stationary tanks. The storage tanks are cylindrical, vertical units with a capacity of approximately 50 tons of CO_2 each. The outer diameter of each tank is 3 meters, and the total height is approximately 11.6 meters. Each tank is insulated with powder-vacuum insulation.

Devices for cryogenic CO_2 purification installations

The table below (Table 14) lists the devices included in the CO_2 purification unit, their description and required device parameters.

Table 14 List of installation devices.

Devices	Description	Required devices parameters
Filter	Removal of solid particles, aerosols and possible mechanical impurities from the gas	Filter type: fabric filter Permissible pressure: approx. 25 bar Made of acid-resistant stainless steel
Precooler	Lowering the gas temperature before the compression process and condensing the moisture	Type: Water cooler with refrigeration unit Cooling medium: Cooling water, glycol Cooling to 5°C
CO_2 compressor	Increasing the pressure of the CO_2 gas stream	Type: Two-stage compressor with interstage cooling Nominal capacity: 550 mN^3/h Compression ratio: up to 20 bar Inlet temperature: 15°C EX (explosion-proof version) Condensate to wastewater
CO_2 adsorption dryer	Deep gas drying	Type: Dual-column, temperature-regenerated adsorption dryer; molecular sieves Inlet pressure: approx. 19.9 bar Inlet temperature: approx. 33°C Outlet temperature: 40°C Final moisture content: approx. 10 ppmv H_2O
Adsorbers	Removal of organic contaminations to a level of approximately 10 ppm	Adsorber battery: 1 pc. filled with activated carbon and 1 pc. filled with impregnated activated carbon Inlet pressure: approx. 19.9 bar Inlet temperature: approx. 40°C Adsorber capacity: approx. 100 kg
CO_2 condenser	CO_2 liquefaction	Nominal capacity: 1000 kg/h Power consumption: approx. 70 kW Inlet temperature: approx. 40°C Inlet pressure: approx. 20 bar Outlet temperature: approx. -30°C
Liquid CO_2 pump	Pumping liquid CO_2 into storage tanks	Made of acid-resistant stainless steel Capacity: 1000 kg/h Power supply: 3-phase (400V)
Distillation column	Removal of physically dissolved trace gases such as CH_4, N_2, O_2, or NO from a liquid CO_2 stream	Distillation of CO_2 stream to food grade purity
Storage tank	Liquid CO_2 storage	Nominal storage capacity: 100 t CO_2 Number of storage tanks: 2 Tank type: stationary cryogenic tank, cylindrical, powder-vacuum insulation Capacity: approx. 50 t CO_2, dimensions: diameter approx. 3 m, height: approx. 11.6 m Storage temperature: approx. -30°C Storage pressure: ~ 20 bar

1.4. Adaptation of the mine shaft for the implementation of the HESS system

1.4.1. Adaptation of the shaft for HESS implementation

Adapting disused mining infrastructure to the needs of a Hybrid Energy Storage System (HESS) is one of the key factors determining the technical and economic feasibility of the project. When using mine shafts as components of an energy storage system, it is necessary to transform the existing infrastructure into a leak-proof, safe, and durable facility capable of long-term operation under variable hydraulic and pressure loads. The adaptation process includes an assessment of the technical condition of the shafts, workings, and surface infrastructure. Analysis includes, among other things, shaft geometry, the condition of the support, the presence of deformations and mechanical damage, hydrogeological conditions, the condition of the rock mass, and the feasibility of modernization work. The results of this assessment form the basis for determining the scope of necessary adaptation work and estimating the capital expenditures associated with implementing the HESS system. If modernization work is necessary, the scope of work may include dismantling existing shaft equipment, repairing and reprofiling the support, local or comprehensive structural reinforcement, new shotcrete layers, sealing injections, and the use of specialized repair materials.

Analyses conducted as part of the project indicated that the Budryk mine shafts were among the most promising locations considered for implementing the HESS system. A significant argument for their selection was the favorable technical condition of the shaft lining, including low wear and tear and no indications of advanced structural degradation. As a result, it was assumed that the shaft infrastructure could provide a suitable base for the HESS system without the need for significant expenditures related to a major reconstruction of the lining. However, it should be emphasized that this assessment refers to the infrastructure condition identified during the design analysis phase. If the investment is implemented, it will be necessary to conduct a new technical diagnostic and update the scope of required adaptation work.

1.4.2. Preparation of the shaft infrastructure and rock mass architecture for plugs in CAES, CCES and PSH systems

One of the most important technical issues related to shaft adaptation is ensuring the proper tightness of underground storage spaces. When storing compressed gas, even minor leaks can lead to energy losses, degraded system performance, and increased operating costs. Therefore, a hydraulic and gas isolation system for the shaft was planned, through the construction of specialized isolation and pressure dams. These structures were individually designed, taking into account the geological and mining conditions, rock mass parameters, and anticipated operating loads.

Due to high operating pressures and variable operating loads, standard cylindrical dams are insufficient. The analyzed solutions envisage the use of multi-segment dams with a wedge geometry, which allow for the transfer of forces to the surrounding rock mass through a self-wedging mechanism. This geometry reduces the risk of the structure being pushed out of the workings and improves stress distribution at the concrete-rock interface. Dam parameters, including their thickness, number of segments, undercut angle, and the scope of preparatory work, should be selected based on the geomechanical properties of the rock mass, shaft geometry, and design operating pressure.

Preparing the dam construction zone involves removing the existing shaft lining at the location, mechanically profiling the rock mass, and constructing a concrete structure in direct contact with the solid rock mass. The scope of this work depends on local geological and mining conditions, the type of existing lining, and the required volume of the structure. At this stage, maintaining the load-bearing capacity of the surrounding rock mass and achieving adequate adhesion between the rock mass and the dam concrete is particularly important.

The next step is the construction of the massive concrete structure. Due to the large volumes of concrete and the requirements for strength and tightness, the concreting process should ensure continuous mix supply, adequate compaction, and limiting the formation of process discontinuities. It is particularly important to avoid so-called cold joints, which could constitute potential migration paths for the working medium and weaken the structure's load-bearing capacity.

Another significant technological challenge is concrete shrinkage during the curing process. In the case of massive concrete dams, temperature differences between the structure's core and the contact zone with the rock mass can lead to the formation of contact gaps. Therefore, after the curing process is complete, high-pressure sealing injections are required to fill the gaps (2K PUR sealing resin) improve the structure's adhesion to the rock mass, and restore full system tightness. This is particularly important in CAES and CCES systems, where even minor leaks can lead to operating fluid losses and reduced storage efficiency.

From a technical and economic perspective, the construction of pressure dams is a significant component of the capital expenditures associated with the adaptation of mine infrastructure. These costs include preparatory work, dismantling of the support in the development zones, rock mass profiling, construction of the concrete structure, sealing injections, quality control, and technical acceptance. The final cost depends primarily on the number of dams, their geometry and volume, the properties of the rock mass, the depth of installation, and the required level of tightness. Therefore, the parameters there should be treated as one of the key input variables in the CAPEX model for the HESS system.

In Shaft II of the Budryk Mine, intended for use as the lower reservoir of the PSH system, three pressure dams were designed. Their function will be to hydraulically isolate the reservoir from other workings and ensure the safe transfer of hydrostatic loads generated during the operation of the pump-turbine system. In Shaft III of the Budryk Mine, intended for the storage of compressed gas (air or carbon dioxide), six pressure dams were planned. The difference in the number of dams results from the larger number of horizontal workings and roadway connections requiring effective isolation from the storage space. For all designed dams, the required strength, geometric parameters, and construction and sealing materials were determined to ensure safe and long-term operation of the system.

Summary of the most important data on barrier dams for PSH, CAES and CCES present Table 15- Table 17.

Table 15 Summary of data on barrier dams for PSH.

Level and inlet [m]	Carved rock [m³]	Dam length [m]	Concrete volume [m³]	Amount of 2KPUR resin [m³]
1050 (E)	8.00	1.60	75.00	0.691
1050 (W)	8.00	1.60	75.00	0.691
1158 (W)	12.00	2.30	110.00	1.012
SUM	28.00	-	260.00	2.394

Dimensions of excavations II Shaft (width, length): 7.8m; 5.5 m.

Table 16 Summary of data on barrier dams for CAES.

Level and inlet [m]	Carved rock [m³]	Dam length [m]	Concrete volume [m³]	Amount of 2KPUR resin [m³]
164 (W)	12.61	2.40	43.57	0.44
500 (W)	32.30	5.40	179.60	1.27
700 (E)	36.38	5.60	197.66	1.31
700 (W)	36.38	5.60	197.66	1.31
1050 (E)	45.63	7.70	372.96	2.395
1050 (W)	45.63	7.70	372.96	2.395
SUM	208.93	-	1364.41	9.12

Dimensions of excavations III Shaft (width, length):

164 m (W) - 3.0m; 4.3 m

500 m (W) - 4.4m, 6.2 m

700 m (E, W) - 4.5m, 6.4 m

1050 m (E, W) - 5.5m, 7.8 m

Table 17 Summary of data on barrier dams for CCES.

Level and inlet [m]	Carved rock [m³]	Dam length [m]	Concrete volume [m³]	Amount of 2KPUR resin [m³]
164 (W)	2.05	1.00	14.95	0.141
500 (W)	2.94	1.00	30.22	0.298
700 (E)	3.02	1.00	31.82	0.316
700 (W)	3.02	1.00	31.82	0.316
1050 (E)	3.66	1.00	46.56	0.463
1050 (W)	3.66	1.00	46.56	0.463
SUM	208.93	-	201.93	1.989

Dimensions of excavations III Shaft (width, length):

164 m (W) - 3.0m; 4.3 m

500 m (W) - 4.4m, 6.2 m

700 m (E, W) – 4.5m, 6.4 m

1050 m (E, W) – 5.5m, 7.8 m

1.4.3. Protective coatings for concrete

To ensure the absolute tightness of the underground storage infrastructure, specialized protective coatings must be applied to the concrete shaft casing before installing the main equipment. Structural concrete alone cannot independently provide the necessary gas-tightness or water-tightness required for high-pressure energy storage. The critical advantage of applying advanced Sikagard resin systems is their profound impact on the casing's structural properties: the multi-layer coating reduces (Fig. 12) the permeability of the concrete by three orders of magnitude. This drastic reduction renders any potential gas or water leakage practically negligible over the facility's operational lifespan. In the case of the PSH system, it also serves as protective protection for the shaft's concrete surfaces against degradation resulting from constant contact with water, cyclical changes in water level, and the impact of aggressive chemicals that may be present in the mine environment.

The adaptation process relies on a rigorous, multi-stage technology to ensure perfect adhesion and absolute sealing:

- **Stage I - Hydrodynamic cleaning**

The prerequisite for any coating application is the thorough preparation of the concrete substrate. This is achieved through high-pressure hydrodynamic washing. The process is executed using specialized high-pressure aggregates working directly in the shaft, paired with buffer tanks installed on the shaft cage to maintain a continuous water supply. This ensures the removal of all loose particles, dust, and contaminants from the shaft walls.

- **Stage II and III - 2K Coating Spraying**

The actual insulation is achieved through the mechanical spraying of two distinct layers of two-component (2K) resin materials. This is carried out using dedicated 2K spraying machines:

- Layer 1 (Sikagard P 770 primer). This foundational layer serves as a deep-penetrating primer. Its precise application is specifically designed to thoroughly seal the micropores and micro-fissures within the concrete substrate, creating an initial impermeable barrier.
- Layer 2 (Sikagard WallCoat T). This serves as the final, closing topcoat. It is sprayed directly onto the primer, creating a durable, highly impermeable, and continuous outer membrane. This closing layer physically protects the concrete matrix and completes the sealing process.

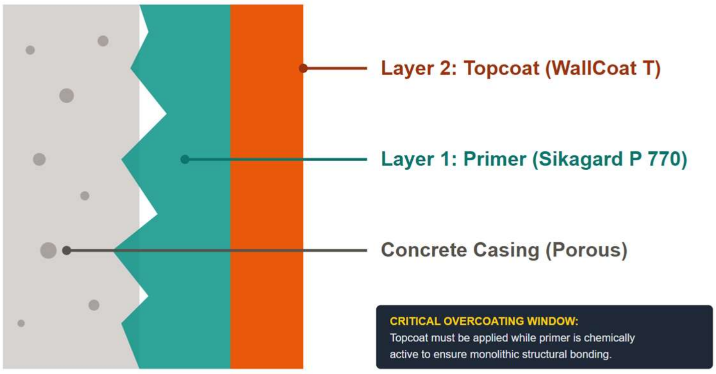

Fig. 12 Cross-section of the concrete shaft casing protected by a synergistic two-layer resin system (Sikagard P 770 primer and WallCoat T topcoat).

Table 18 Summary of demand for coating in II and III Shaft of Budryk Mine.

	Demand for coating in II Shaft	**Demand for coating in III Shaft**
Sikagard P 770 (primer)	11 295.65 kg (incl. 15% losses)	10 632.56 kg (incl. 15% losses)
Sikagard WallCoat T (topcoat)	10 542.60 kg (incl. 15% losses)	9 923.72 kg (incl. 15% losses)

II Shaft surface – 32 741 m^2 , III Shaft surface – 30 819 m^2

1.4.4. Servece ventilation

The specific nature of underground energy installations requires the implementation of advanced ventilation systems, which together guarantee the maintenance of rigorous safety standards and the failure-free operation of the equipment. In the case of adapting inactive mine shafts for the needs of Hybrid Energy Storage Systems (HESS), transforming the excavation into a facility capable of cyclic operation under high pressure requires integrated modernization and securing works, making the organization of ventilation during construction and subsequent inspection descents a distinct engineering challenge.

During the shaft adaptation phase and service descents, the key solution ensuring a safe atmosphere is a temporary forced ventilation system. Unlike exhaust systems, forced ventilation involves the mechanical pumping of fresh air from the surface directly to the bottom of the shaft via a ventilation duct. The overpressure generated in the working zone in this manner guarantees the immediate dilution and expulsion of any hazardous gases (CO_2, CH_4) or oxygen-deficient air. The exhaust air then returns to the surface, rising through the entire free cross-section of the shaft. The system is powered by a surface high-pressure fan station, integrated with an inverter system, which enables dynamic adjustment of the airflow based on gasometry sensor readings (Fig. 13).

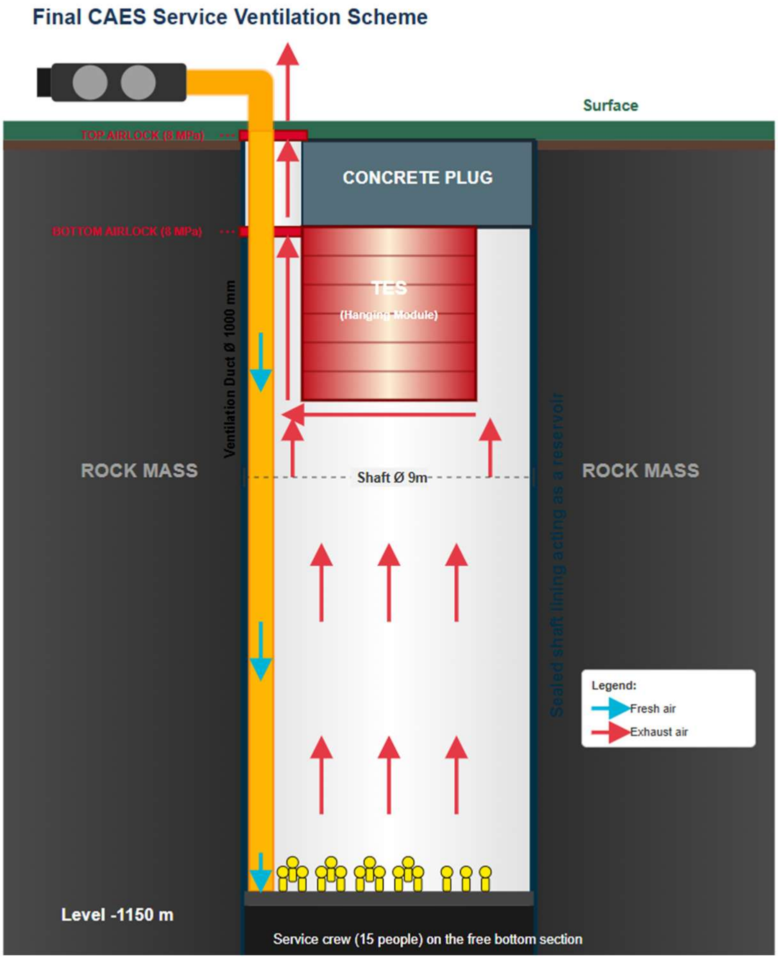

Fig. 13 Temporary ventilation in shaft.

The distribution of air to the working level is carried out using large-diameter flexible ventilation ducts (e.g., 1000 mm in diameter). They are made of high-strength, flame-retardant, and antistatic technical fabrics coated with plastics (e.g., PVC). The flexible design allows the ducting to smoothly adapt to the excavation space and facilitates its efficient installation and dismantling. Due to the extreme tensile forces generated by the installation's own weight over a distance of more than a kilometer, the sequentially lowered duct cannot hang freely in the shaft. It is required to route steel support ropes alongside it and systematically install stabilizing clamps anchored directly to the casing. This prevents aerodynamic vibrations, duct pulsation, and the risk of individual sections tearing under the pressure of the forced air.

The fundamental feature of the described system is its strictly temporary nature. Upon completion of the main front of construction and assembly works (such as sidewall reprofiling or pouring pressure plugs) and the withdrawal of the crew, the entire line of the flexible duct is successively dismantled and pulled to the surface. Thanks to the use of flexible materials, the ventilation pipes can be easily compressed and extracted using shaft hoists. In the final operational phase of the energy storage facility, the shaft space must remain completely free of any temporary auxiliary infrastructure, which is an absolute condition for maintaining full tightness and preserving the structural integrity of the underground pressure vessel.

Table 19 Summary of ventilation system specification.

Item	Specification
Ventilation duct	Diameter 1000 mm, antistatic technical fabrics coated with plastics, 1200 mb
Fans	2 x 37 kW set (series system), inverters
Suspensions and mounting	Support ropes, anchoring, assembly accessories
Automation and detection	Control cabinets, gas sensors

1.4.5. The dewatering system

The dewatering system of the Budryk mine is based on two independent and equivalent technological lines. One serves as the primary dewatering system, while the other functions as a backup system, activated in the event of a failure, maintenance work, or shutdown of the primary line. This arrangement ensures a high level of reliability and operational safety, which is particularly important for protecting the underground infrastructure from uncontrolled water level increases.

The dewatering system remains operational and ready for use 24 hours a day; however, this does not mean that the pumps operate continuously. Their operation depends on the actual water level in the underground workings and retention reservoirs. The pumps are automatically activated when predefined water levels are reached and are switched off once the water level has been reduced to a safe threshold. In practice, the operating time of the pumps may be approximately 20 hours per day, although it depends on water inflow rates, hydrogeological conditions, and current operational circumstances.

Within the analysed scenario of adapting the shafts for the HESS system, the construction of an additional emergency dewatering system is not foreseen. The existing infrastructure has been designed in accordance with mining safety requirements and already provides full redundancy through the use of two independent pumping lines. Therefore, it is assumed that the current dewatering system can continue to be used after the implementation of HESS, subject to verification of its technical condition and confirmation of its suitability for operation under the new conditions associated with the energy storage system.

1.5. Modelling results

As part of the Task 7.1, based on the data presented in the technical description of the HESS system and its subsystems, mass and energy balances were developed, taking into account the integration of three energy storage technologies: a pumped storage hydropower plant (PSH), a compressed gas energy storage system (CAES/CCES) and a thermal energy storage (TES).

Basic technological parameters were determined for each of the analysed subsystems, described in the technical description of the analysed variants. Tables 20, 21 and 22 present the results of the mass and energy balances for the analysed subsystems.

Table 20 Parameters adopted for the design of the PSH module.

Parameter	Value
Total shaft depth, m	1157.45
Shaft diameter, m	9
Lower reservoir depth, m	200
Maximum geometrically available useful head, m	950
Conservative design head adopted for calculations, m	900
Lower reservoir capacity, m^3	12 719
Operational working volume, m^3	12 000
Hydropower unit efficiency, -	0.7
Gravitational acceleration, m/s^2	9.81
Water density, kg/dm^3	1
Energy storage capacity, MWh	**23.06**

Table 21 A-CAES modelling results.

Parameters	Value
Total electric power – compressor, MW	33.28
Electric energy consumed per cycle, MWh	166.4
Air mass flow rate – charging, kg/s	56.61
C1 section outlet pressure, MPa	0.4
C1 section outlet temperature, °C	155
C2 section outlet temperature, °C	up to 500
Maximum air pressure drop (charging), kPa	19.64
Maximum air pressure drop (discharging), kPa	54.69
Average air pressure before expansion, MPa	3.74
Total electric power – expander, MW	36.00
Electric energy produced per cycle, MWh	108
Air mass flow rate – discharging, kg/s	94.34
Round-trip efficiency, -	0.65
Plug height (analysed variant), m	100

Table 22 CCES modelling results.

Parameters	Value
Total electric power – compressor, MW	10.06
CO_2 mass flow rate – charging, kg/s	39.88
Electric energy consumed per cycle, MWh	50.32
Total electric power – expander, MW	10.84
CO_2 mass flow rate – discharging, kg/s	66.46
Outlet pressure (to LPT), MPa	0.64
Electric energy produced per cycle, MWh	32.52
Round-trip efficiency, -	0.65
Required net storage volume (LPT), m^3	63 300
Required net storage volume (HPT), m^3	1 023
Plug diameter, m	9.0
Plug height (analysed variant), m	20

HPT – High Pressure Tank
LPT – Low Pressure Tank
HE - Heat Exchenger

2. Economic analysis

Economic analysis was carried out for 2 analysed variants, described in unit 1.2 of this report:

- Variant 1: PSH with CAES/TES,
- Variant 2: PSH with CCES/TES.

Economic analysis was calculated based on the assumption that all subsystems analysed in both variants were optimised for maximization of the profit from arbitrage prices of electricity in Polish market.

2.1. Arbitrage system

Arbitrage system is based on a practice of taking advantage of a difference in prices of electricity in different moments. For Polish market, main source of the data necessary for arbitrage calculations is Day Ahead Market, operated by TGE.

For the subsystems parameters described in the modelling part of the report, annual energy production and consumption for each of the analysed subsystems was calculated. Calculations were based on the maximisation of the profit from price arbitrage. Data for price arbitrage calculations were obtained from Deliverable 6.1 of the project, where summary of the average electricity prices on the Day-Ahead-Market for 2021, 2023 and 2024 was presented. Table 23 presents results of the calculation for analysed subsystems, showing technical, operational and economic results.

Table 23. Technical, operational and economic comparison of the analysed energy storage systems: PSH, CAES and CCES.

Type of storage	PSH	CAES	CCES
Storage capacity, MWh	23.25	108	32.58
Storage capacity / pressure tank, m^3	-	62 751	1023
Expanded CO_2 storage capacity -LTP, m^3	12 700	-	63 300
Production time at max capacity, h	4	3	3
Charging time at max capacity, h	8	5	5
Annual energy production, MWh	7865.3	30656.7	9229.2
Production efficiency, %	60.01%	65.00	64.75%
Number of hours with max. tank filling, h	2094	2761	2761
Number of hours with min. tank filling, h	4100	4307	4307
Hours of production cycles,	1365	931	852
Hours of charging cycles,	2616	1417	1417
Amount of energy produced from storage capacity MWh/MWh	338.3	283.9	283.3
Amount produced from storage volume (HTP+LTP) MWh/m^3	0.155	0.489	0.143
Profit from price arbitrage, PLN			
January	-163 383	-81 320	-50 753
February	-105 933	-2 939	-21 095

March	-81 073	21 175	-17 735
April	-74 044	165 749	26 316
May	-15 302	473 881	109 662
June	47 688	1 021 788	266 701
July	162 396	1 562 442	427 544
August	207 158	1 783 253	498 726
September	179 375	1 150 586	315 393
October	51 285	673 607	166 151
November	18 311	671 517	166 708
December	-22 043	492 418	116 162
Total	204 435	7 932 158	2 003 780
Unit profit PLN/MWh	26	259	217

2.2. CAPEX estimation

The capital cost estimate was conducted in accordance with the Cost Estimate Classification System presented by AACE International (Association for the Advancement of Cost Engineering), and capital cost calculations were performed to AACE Class 4 accuracy. All costs presented in the report are net costs. The cost estimation methodology included determining bare erected cost (BEC), engineering, procurement, and construction cost (EPCC), total plant cost (TPC), and total overnight cost (TOC).

Table 24.AACE International Cost Estimation Accuracy Classification.

Accuracy class	Project implementation level [%]	Typical Estimation Goal	Expected accuracy range [%]
Class 5	0% do 2%	Project concept	L: -20% do -50%, H: +30% do +100%
Class 4	1% do 15%	Feasibility study	L: -15% do -30%, H: +20% do +50%
Class 3	10% do 40%	Budget, Permits and Control	L: -10% do -20%, H: +10% do +30%
Class 2	30% do 75%	Control, bidding	L: -5% do -15%, H: +5% do +20%
Class 1	65% do 100%	Checking the estimate, making offers	L: -3% do -10%, H: +3% do +15%

The calculations were based on data obtained through consultations with external companies, as well as own knowledge and experience. Estimates were made based on the adopted expenditure structure, which included the following items:

1. Bare erected cost (BEC) –include the cost of equipment and devices, as well as the costs of construction, assembly, and installation of equipment, along with other costs directly related to the construction of the installation. Equipment cost estimates are frequently developed for each plant or plant component using in-house database and conceptual estimating models for specific technologies.
2. Engineering, procurement, and construction cost (EPCC) –include bare erected cost plus services provided by he EPC contractor such as detailed design, project management cost, site preparation, and other indirect cost.

3. Total plant cost (TPC) –include EPCC costs plus items such as process contingency and project contingency.
4. Total overnight cost (TOC) –includes total plant costs plus pre-production costs, spare parts costs, and other investor costs (legal costs, studies, investor engineering costs, management reserve, etc.).

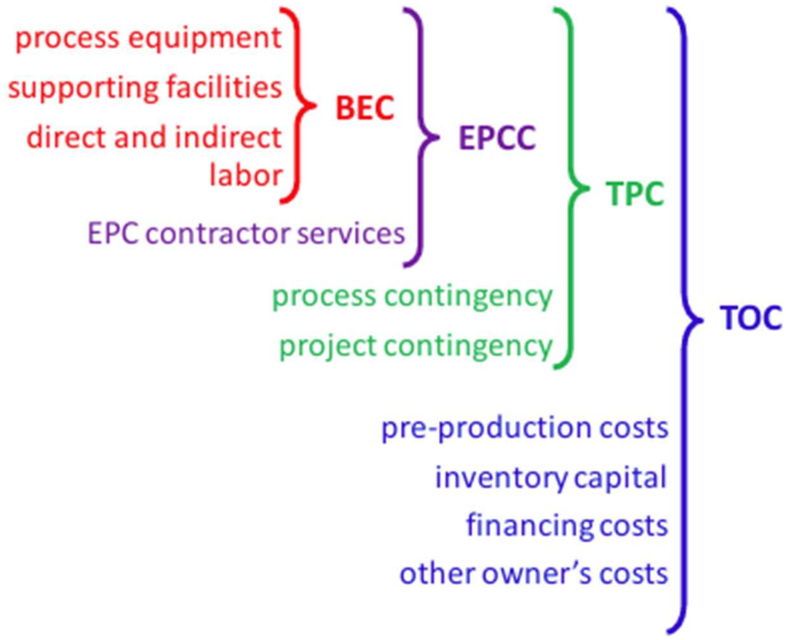

Fig. 14 Capital cost levels and their elements.

2.2.1. Bare erected cost for PSH

Bare erected cost for the PSH system was determined in several steps. In the first step, the total equipment cost (TEC) was estimated based on an analysis of the system's technical specifications, as well as an analysis of available literature, public materials, and consultations with technology suppliers.

Main assumptions for TEC estimation:

- the calculations were based on the cost estimates for the turbine with generator and the pumps, as provided by the technology suppliers,
- the cost estimate for the pipelines was based on an estimate of the total weight, including the pipelines and all the fittings and construction necessary for their installation.
- auqiliary equipment was estimated using indicator method and included all additional equipment (valves, nozzles, deflectors).

Table 25.Total equipment cost - PSH

Cost	Value, EUR
Vertical Pelton Turbine with synchronious generator	1 683 883
Turbine - Pipelines	3 476 086
Pumps	693 364
Pumps – Pipelines	8 540 681
Auxiliaty equipment	1 727 282
Total equipment cost (TEC)	16 121 295

Second step was to deteremine cost of supporting facilities, direct and indirect labor. This consisted of cost componenets:

- Mine shaft sealing plugs,
- Mine shaft sealing (Wallcoat),
- Upper reservoir construction,
- Platforms assembly,
- Civil works,
- Auxiliary installations (instrumentation, electrical, services),
- Labor, materials (construction, mounting of main equipment etc.).

Table 26.Supporting facilities, direct & indirect labor - PSH

Cost	Value, mln EUR
Main shaft sealing plugs	148 800
Concrete	45 988
Resin	40 328
Labor	61 747
Energy	737
Mine shaft sealing	521 197
Material P 770	192 390
Matreial WallCoat T	158 505
Labor	164 520
Energy	4 238
Process water + wastewater	1 545
Upper reservoir construction	1 039 196
Excavation	132 069
Embankments	76 411
Geotextile	12 264
Dolomite aggregate	216 499
Concrete screen	212 254
Tranport & installation	389 699
Platforms assembly	638 343
Upper platform	174 662
Lower platform	383 496
Civil works	1 450 917
Auxiliary installations	8 703 364
Electric	5 479 105
Instrumentation & control	2 418 194
Services	806 065
Labor, materials	12 374 732

Bare erected cost based on the cost components presented in the analysis was estimated at 40 997 843 EUR.

2.2.2. Bare erected cost for A-CAES

Bare erected cost for the A-CAES system was determined similar to PSH system. All cost components were estimated based on an analysis of the system's technical specifications, as well as an analysis of available literature, public materials, and consultations with commercial suppliers.

Table 27 The A-CAES cost assumptions.

Area of costs	Description of area	Indicative values [PLN] / ranges	Literature sources
Compressors	Compressors are responsible for the charging phase. Their cost depends on capacity, number of compression stages, final pressure, intercooling arrangement, and efficiency.	1.23million/MW.	[2] [3]
Expanders	Expanders determine the power delivered to the grid and are the most expensive single machinery component.	2.41 million/MW.	[2] [3]
Compressed-air storage	Underground structures are generally the most favourable option, especially salt caverns; in Poland, mine shafts and underground post-mining workings may be an alternative.	Cost strongly depends on location, tightness, geological conditions, and the required scope of adaptation.	[4]
Thermal Energy Storage – TES	TES is a key element of A-CAES systems; it enables recovery of compression heat and operation without gaseous fuel.	The cost strongly depends on the technological solution adopted	[5]
Basalt	In European practice, for larger contracts, prices in the range of 80-150 PLN/t. For the purposes of this analysis, a value of 115 PLN/t has been assumed.	115 /t	-
Civil works	This category includes the machinery hall, electrical annex, yards, access roads etc.	0.54–0.83 million/MW.	[4] [6]
Auxiliary equipment	This category includes the cost of pipelines, valves, intercoolers etc.	Cost strongly depends on the configuration of the system	-

[2] Mongird, K., Viswanathan, V., Alam, J., Vartanian, C.: Pacific Northwest National Laboratory (2020 Grid Energy Storage Technology Cost and Performance Assessment. U.S. Department of Energy).
[3] Moore, J. J., Allison T., Evans T., Kerth, J., Pacheco J.: Development and testing of multi-stage internally cooled centrifugal compressor," w 44th Turbomachinery & 31st Pump Symposia, Houston, 2015.
[4] Lutyński, M.: An overview of potential benefits and limitations of Compressed Air Energy Storage in abandoned coal mines. IOP Conference Series: Materials Science and Engineering, 2017.
[5] Jurczyk, M., Spietz, T., Czardybon, A., Dobras, S., Ignasiak, K., Bartela, Ł., Uchman, W., Ochmann, J.: Review of thermal energy storage materials for application in large-scale integrated energy systems—methodology for matching heat storage solutions for given applications. Energies 17, 2024.
[6] Ochmann, J., Jurczyk, M., Rusin, K., Rulik, S., Bartela, Ł., Uchman, W.: Solution for post-mining sites: thermo-economic analysis of a large-scale integrated energy storage system. Energies 17, 2024.

Mine shaft sealing dams	This category includes the cost of labor and materials needed to prepare 6 sealing dams,	Cost was estimated based on the analysis of dimensions of the dams required to sustain the pressure of 8 MPa inside the shaft	-
Mine shaft sealing	This category includes cost of shaft walls sealing	Cost was estimated for 3-stage coating using Sikagard P 770 and Wallcoat T technology, for calculated consumption of all materials and labor	-
Mine shaft sealing plug	This category includes cost of shaft walls plug	Cost depends on the dimension of the shaft, maximum pressure of the compressed air and	
Auxiliary installations	This category includes electrical installation, instrumentation and other services.	Cost was calculated using indicators for main cost components of the installations	-
Labour, materials	This category includes labor and materials factors necessary to convert FOB costs of main equipment to bare module costs, which includes all cost of fully installed and functioning unit	Cost was estimated based on Capital Cost Guidelines for different equipmenc components	7

Based on the presented assumptions, bare erected cost was estimated using abovementioned methodology.

Table 28.A-CAES bare erected cost estimation

Cost component	**Value, EUR**
Compressor unit	9 653 884
Expander unit	20 461 299
Thermal energy storage	2 979 459
Thermal energy storage tank	2 830 055
Basalt	149 403
Auxiliary equipment	3 478 609
Total equipment cost (TEC)	**36 573 251**
Main shaft sealing dams	559 116
Concrete	241 335
Resin	153 530
Labor	160 284
Energy	3 967
Mine shaft sealing	491 987
Material P 770	181 096
Matreial WallCoat T	149 200
Labor	156 219
Energy	4 015
Process water + wastewater	1 454
Mine sealing plug	10 612 707
Civil works	5 285 128
Auxiliary installations	22 179 869
Electric	14 712 160

[7] Rules of Thumb in Engineering Practice Donald R. Woods, 2007, WILEY-VCH Verlag GmbH & Co. KGaA, Weinheim, ISBN: 978-3-527-31220-7

Instrumentation & control Maintenance ventillation Services	5 485 988 153 059 1 828 663
Labor, materials	15 101 486
Bare erected cost (BEC)	**90 650 484**

2.2.3. Bare erected cost for CCES

Bare erected cost for the CCES system was determined similar to PSH and A-CAES system. All cost components were estimated based on an analysis of the system's technical specifications, as well as an analysis of available literature, public materials, and consultations with commercial suppliers.

Table 29 The CCES cost assumptions.

Area of costs	Description of area	Indicative values [PLN] / ranges	Literature sources
Compressors	Compressors are responsible for the charging phase. Their cost depends on capacity, number of compression stages, final pressure, intercooling arrangement, and efficiency. There is a lack of published data on CO_2 compressors. Pricing from suppliers requires a case-by-case approach.	1.23million/MW.	[2] [3]
Expanders	Expanders determine the power delivered to the grid and are the most expensive single machinery component. There is a lack of published data on CO_2 expanders. Pricing from suppliers requires a case-by-case approach.	2.41 million/MW.	[2] [3]
Carbon dioxide low-pressure storage	Cost strongly depends on location, tightness, geological conditions, and the required scope of adaptation.	Cost strongly depends on location, tightness, geological conditions, and the required scope of adaptation.	[8]
Carbon dioxide high-pressure storage	Cylindrical steel or composite tanks must be used. The largest tanks available have a capacity of up to 17 m^3.	For the estimation specific cost of 30,000/m^3 was assumed, for 250 bar storage including all auqiliary equipment necessary for the storage to work.	[8]
CO_2	Initial fill of the system requires over 700 Mg of pure CO_2	According to CO_2 price indexes fo European market, price of 1.20/kg was assumed	-
Carbon dioxide purification system	Cryogenic CO_2 purification was implemented for effective removal of non-condensable gases and CO2 purity above 99.99%.	Cost was estimated based on the analysis of efficiency of the process, stream of CO_2 required for purification and technological concept of the purification system	-

[8] Brzuszkiewicz M., Analiza techniczno-ekonomiczna oraz optymalizacja hybrydowego systemu magazynowania energii w sprężonym dwutlenku węgla oraz wodorze. Rozprawa doktorska, Politechnika Śląska, Gliwice, 2025.

TES tank - basalt	TES is a key element of CCES systems; it enables recovery of compression heat and operation without gaseous fuel.	The cost strongly depends on the technological solution adopted	-
TES tanks – thermal oil	Based on experience with PCS-type investments, a value of 3,000 EUR/m^3 can be assumed. For the purposes of this analysis, a value of 12,000 PLN/m^3 has been assumed.	12,000/m^3	-
Thermal oil	In European practice, for larger contracts relating to new CSP plants or high-temperature industrial systems, prices in the range of 4-10 EUR/kg. For the purposes of this analysis, a value of 16 PLN/kg has been assumed.	16,000/t	[9]
Basalt	In European practice, for larger contracts, prices in the range of 80-150 PLN/t. For the purposes of this analysis, a value of 115 PLN/t has been assumed.	115 /t	-
Heat exchangers	High-pressure supercritical CO_2/thermal oil heat exchangers are not widely used. Economic analyses are currently being carried out as part of research.	For the purposes of this analysis, a value of 1,44 mlnEUR/MW has been assumed	[10]
Civil works	This category includes the machinery hall, electrical annex, yards, access roads etc.	0.54–0.83 million/MW.	[4] [6]
Auxiliary equipment	This category includes the cost of pipelines, valves, intercoolers etc.	Cost strongly depends on the configuration of the system	-
Mine shaft sealing dams	This category includes the cost of labor and materials needed to prepare 6 sealing dams	Cost was estimated based on the analysis of dimensions of the dams required to sustain the pressure of 0,96 MPa inside the shaft	-
Mine shaft sealing	This category includes cost of shaft walls sealing	Cost was estimated for 3-stage coating using Sikagard P 770 and Wallcoat T technology, for calculated consumption of all materials and labor	-
Mine shaft sealing plug	This category includes cost of shaft walls plug	Cost depends on the dimension of the shaft, maximum pressure of the compressed air and	-
Auxiliary installations	This category includes electrical installation, instrumentation and other services.	Cost was calculated using indicators for main cost components of the installations	-

[9] Outana I., at al., Comparative techno-thermal analysis of a parabolic trough power plant with thermocline storage: Multi-climatic simulations in Morocco using different heat transfer fluids. Case Studies in Thermal Engineering 82 (2026) 108133 https://doi.org/10.1016/j.csite.2026.108133.
[10] Girelli S., et al., Design and techno-economic assessment of a transcritical CO_2 pumped thermal energy storage system. Energy 2025;339:138902. https://doi.org/10.1016/j.energy.2025.138902

Labour, materials	This category includes labor and materials factors necessary to convert FOB costs of main equipment to bare module costs, which includes all cost of fully installed and functioning unit	Cost was estimated based on Capital Cost Guidelines for different equipmenc components	-

Based on the presented assumptions, bare erected cost was estimated using abovementioned methodology.

Table 30.CCES bare erected cost estimation

Cost component	**Value, EUR**
Compressor unit	2 917 315
Expander unit	6 160 087
Thermal energy storage	8 688 269
TES tank - basalt	2 358 379
Basalt	66 035
TES tank – thermal oil	4 414 886
Thermal oil	1 848 969
Heat exchangers	2 146 125
$HPCO_2$ storage	7 237 866
CO_2 initial fill	203 153
CO_2 purification system	1 562 190
Auxiliary equipment	4 930 145
Total equipment cost (TEC)	**33 845 151**
Main shaft sealing dams	142 809
Concrete	35 717
Resin	33 506
Labor	73 089
Energy	497
Mine shaft sealing	491 987
Material P 770	181 096
Matreial WallCoat T	149 200
Labor	156 219
Energy	4 015
Process water + wastewater	1 454
Mine sealing plug	2 122 541
Civil works	2 121 881
Auxiliary installations	15 629 020
Electric	8 859 990
Instrumentation & control	5 076 773
Services	1 692 258
Labor, materials	17 915 947
Bare erected cost (BEC)	**72 269 335**

2.2.4. Bare erected cost of router + grid connection

This system is analysed as integrated system of energy router compiled with grid connection system:

- Energy router includes cost components such as site preparation, container with ventillation system, main equipment (router, control cabinet, server), operator workstation, as well as costs od transportation and installation on-site, comissioning, programming, documentation and intergation with PSH, A-CAES and CCES sytems.

- Grid connection system includes cost components such as step-up transformers, high-voltage switchgear, powerhouse electrical building, fire protection systems, HVAC and cooling systems, DC power supply and UPS, grounding and lightning protection systems and auxiliary infrastructure.

Table 31.CCES bare erected cost estimation

Cost component	Value, EUR
Router	**141 739**
Control cabinet, server	43 394
Operator workstation	4 953
Container + HVAC	10 613
Site preparation	8 254
Transport, installation	20 990
Documentation, commissioning, programming	25 235
Integration with PSH, A-CAES, CCES	28 301
Grid conncetion	**16 927 268**
Step-up transformer	2 256 969
High-voltage switchgear	3 898 401
MV/HV cables + penetrations	2 564 738
Powerhouse electrical building	3 077 685
Fire protection system	615 537
HVAC + cooling systems	923 306
DC power supply + UPS	718 127
Grounding + lightning protection	615 537
Auxiliary electrical systems	2 256 969
Bare erected cost (BEC)	**17 069 006**

2.2.5. Total overnight cost

<u>Engineering, procurement and construction cost (EPCC)</u>

Based on NETL guidelines, EPCM contractor services were estimated at 15 percent of BEC. These costs consist of all home office engineering and procurement services as well as field construction management costs.

<u>Total plant cost (TPC)</u>

Total construction costs (TPC) were estimated based on the following assumptions and findings that

- Process risk costs were estimated based on the AACE guidelines, which present the following process risk ranges:

Table 32. AACE Process Risk Guidelines

Technology status	Process Contingency
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

- Depending on the cost component, 0-15% process contingency was assumed.

- Based on AACE guidelines, the cost of project contingency for accuracy class 4 was assumed to be 15% of EPCC.

Total overnight cost (TOC)

Total overnight costs were calculated based on the NETL and AACE guidelines, as well as own knowledge and experience. Specific assumptions are presented below:

- For pre-production costs, based on the NETL guidelines, 2% of TPC for other costs were assumed,
- For Inventory capital costs, 0.5% of TPC was assumed for spare parts,
- For other owner's costs 15% of TPC was assumed for costs such as preliminary studies, permitting costs, legal fees, site improvements outside of the facility boundaries, owner's engineering, owner's contingencies etc.

Calculation of Total Overnight cost (TOC)

Based on the presented expenditure structure and the adopted assumptions, the total investment expenditure (TOC) was determined and the results are presented in the tablesbelow.

Table 33. Total overnight cost (TOC) - PSH

Costs Area	Costs, EUR
Pelton turbine	1 683 883
Pumps	693 364
Turbine - Pipelines	3 476 086
Pumps – Pipelines	8 540 681
Auxiliary equipment	1 727 282
Total equipment cost (TEC)	16 121 295
Mine shaft sealing	148 800
Mine shaft sealing plug	521 197
Upper reservoir	1 039 196
Platform assembly	638 343
Civil works	1 450 917
Auxiliary installations (instrumentation, electrical, services)	5 479 105
Labour, materials (construction, installation etc.)	12 374 732
Bare erected cost (BEC)	**40 997 843**
Contracting Strategy and EPC Contractor Services	6 149 676
Engineering, procurement and construction cost (EPCC)	**47 147 520**
Process Contingency	1 013 828
Project Contingency	7 072 128
Total plant cost (TPC)	**55 233 475**
Preproduction (Start-Up) Costs	276 167
Inventory Capital	1 104 670
Other Owner's Costs	8 285 021
Total overnight cost (TOC)	**64 899 334**

Table 34. Total overnight cost (TOC) – A-CAES

Costs Area	**Costs, EUR**
Compressor unit	9 653 884
Expander unit	20 461 299
Thermal energy storage	2 979 459
Auxiliary equipment	3 478 609
Total equipment cost (TEC)	**36 573 251**
Mine shaft sealing	491 987
Mine shaft sealing dams	559 116
Mine shaft sealing plug	10 612 707
Civil works	5 285 128
Auxiliary installations (instrumentation, electrical, services)	22 179 869
Labour, materials (construction, installation etc.)	15 101 486
Bare erected cost (BEC)	**90 650 484**
Contracting Strategy and EPC Contractor Services	13 597 573
Engineering, procurement and construction cost (EPCC)	**104 248 057**
Process Contingency	2 012 007
Project Contingency	15 637 209
Total plant cost (TPC)	**121 897 273**
Preproduction (Start-Up) Costs	609 486
Inventory Capital	2 437 945
Other Owner’s Costs	18 284 591
Total overnight cost (TOC)	**143 229 295**

Table 35. Total overnight cost (TOC) – CCES

Costs Area	**Costs, EUR**
Compressor unit	2 917 315
Expander unit	6 160 087
Thermal energy storage	8 688 269
Heat exchangers	2 146 125
$HPCO_2$ storage	7 234 866
CO_2 initial fill	203 153
CO_2 purification system	1 562 190
Auxiliary equipment	4 930 145
Total equipment cost (TEC)	**33 845 151**
Mine shaft sealing	491 987
Mine shaft sealing dams	142 809
Mine shaft sealing plug	2 122 541
Civil works	2 121 881
Auxiliary installations (instrumentation, electrical, services)	15 629 020
Labour, materials (construction, installation etc.)	17 915 947
Bare erected cost (BEC)	**72 269 335**
Contracting Strategy and EPC Contractor Services	10 840 400
Engineering, procurement and construction cost (EPCC)	**83 109 736**
Process Contingency	475 641
Project Contingency	12 466 460
Total plant cost (TPC)	**96 051 837**

Preproduction (Start-Up) Costs	480 259
Inventory Capital	1 921 037
Other Owner's Costs	14 407 776
Total overnight cost (TOC)	**112 860 908**

Table 36. Total overnight cost (TOC) – router + grid connection

Costs Area	**Costs, EUR**
Router	141 739
Grid connection	16 927 268
Bare erected cost (BEC)	**17 069 006**
Contracting Strategy and EPC Contractor Services	2 539 090
Engineering, procurement and construction cost (EPCC)	**19 608 096**
Process Contingency	-
Project Contingency	2 941 214
Total plant cost (TPC)	**22 549 311**
Preproduction (Start-Up) Costs	112 747
Inventory Capital	447 726
Other Owner's Costs	3 382 397
Total overnight cost (TOC)	**26 492 180**

Based on the results presented for each of analysed system, TOC analysis was carried out for 2 analysed variants, described in unit 1.2 of this report:

- Variant 1: PSH with CAES/TES,
- Variant 2: PSH with CCES/TES.

Table 37. Total overnight cost (TOC) for analysed Variants

Costs Area	**Variant 1**	**Variant 2**
Bare erected cost (BEC)	**148 717 334**	**130 336 185**
Contracting Strategy and EPC Contractor Services	22 286 339	19 529 167
Engineering, procurement and construction cost (EPCC)	**171 003 673**	**149 865 352**
Process Contingency	3 025 835	1 489 468
Project Contingency	25 650 551	22 479 803
Total plant cost (TPC)	**199 680 059**	**173 834 623**
Preproduction (Start-Up) Costs	998 400	869 173
Inventory Capital	3 990 341	3 473 432
Other Owner's Costs	29 952 009	26 075 193
Total overnight cost (TOC)	**234 620 809**	**204 252 422**

Analysis shows that Variant 1 is slightly more expensive, due to the higher TOC of CAES system comparing to CCES system. Analysis shows that the most expensive cost component of both variants is the CGES system accounting for 61% (CAES) and 55% (CCES) of TOC of the relevant variant.

Specific CAPEX indicators were calculated for each of analysed energy storage system:

- Specific cost per kilowatt of maximum power generation; EUR/kW,
- Specific cost per kilowatt hour of maximum energy storage; EUR/kWh.

Table 38. Total overnight cost (TOC) – router + grid connection

Parameter	PSH	A-CAES	CCES
Maximum power generation, MW	5.8	36	10.84
Maximum energy storage, MWh	23.06	108	32.52
Total overnight cost (TOC), EUR	64 899 334	143 229 295	112 860 908
Specifi power generation cost, EUR/kW	11 190	3 979	10 412
Specific energy storage cost, EUR/kWh	2 814	1 326	3 471

2.3. OPEX estimation

OPEX calculation was carried out for 2 categories of operation expenditures – variable and fixed costs. Variable cost included cost of electricity purchase depending on the number of cycles, processed energy, efficiency losses, and internal electricity consumption. Fixed costs included technical readiness, servicing, inspections, personnel, technical supervision, and maintenance of auxiliary systems.

OPEX estimation was carried out using OPEX indicators, available in the public literature. Calculation was divided into 2 stages: in the first stage, O&M costs were calculated based on the available literature data. In the second stage, cost of electricity consumption was calculated based on the arbitrage system data.

Table 39 O&M cost assumptions.

Area of costs	Description of area	Value, EUR	Literature sources
Fixed O&M for PSH	Calculated using formula: $O\&M\ (USD) = 34{,}730 \cdot P^{0.32} \cdot AE^{0.33}$ P – plant capacity (MW) AE – annual energy throughput (MWh)	1 041 140	2
Fixed O&M for A-CAES	Literature show typical fixed O&M costs for CAES in the range of 12.3-20.1 USD/kW. For the calculation, upper value was taken into account.	639 717	2
Fixed O&M for CCES	Assumed similar to A-CAES, but due to lower power generation, scaling factor of 0.5 was used for scaling of fixed OPEX by power generation.	351 036	2
Variable O&M for PSH	According to the literature, PSH shows no variable OPEX costs	-	2
Variable O&M for A-CAES	Literature show typical variable O&M costs for CAES in the range of 1.7-2.5 USD/MWh. For the calculation, upper value was taken into account.	67 825	2
Variable O&M for CCES	Assumed similar to A-CAES, but due to lower energy production, scaling factor of 0.5 was used for scaling of fixed OPEX by energy production.	37 216	2

According to O&M estimation presented, total OPEX for both analysed variants was calculated.

Table 40. O&M calculation for analysed variants

OPEX	Variant 1	Variant 2
Fixed O&M	1 680 857	1 392 176
Variable O&M	67 825	37 216
Total O&M	1 748 682	1 429 392

Calculation for electricity consumption was carried out based on arbitrage data acquired during the works on Deliverable 6.1. Monthly energy consumption was estimated, as well as mean electricity prices based on the data acquired for Day-Ahead-Market data for year 2024. Calculations were carried out for each of the analysed systems.

Table 41. Electricity consumption cost - PSH

Month	Electricity consumption, MWh	Mean electricity price, EUR/MWh	Electricity cost, EUR
January	1 218.8	81.99	99 937
February	1 072.5	66.60	71 428
March	1 107.6	64.19	71 100
April	1 062.5	65.13	69 196
May	1 117.6	59.54	66 543
June	1 027.4	72.12	74 097
July	972.3	58.73	57 097
August	1 072.5	47.48	50 923
September	1 057.4	51.28	54 231
October	1 172.7	73.94	86 708
November	1 107.6	93.32	103 359
December	1 117.6	81.45	91 025
TOTAL	**13 106.3**	**68.34**	**895 644**

Table 42. Electricity consumption cost – A-CAES

Month	Electricity consumption, MWh	Mean electricity price, EUR/MWh	Electricity cost, EUR
January	3 361.6	76.11	255 836
February	3 328.3	57.44	191 195
March	3 627.9	61.69	223 786
April	3 661.2	55.35	202 662
May	4 826.1	52.08	251 343
June	4 360.1	60.55	264 026
July	4 493.2	50.19	225 511
August	4 659.7	33.71	157 077
September	3 827.6	43.02	164 679
October	3 927.4	68.74	269 985
November	3 461.5	75.89	262 704
December	3 627.9	69.08	250 631
TOTAL	**47 162.4**	**57.66**	**2 719 436**

Table 43. Electricity consumption cost - CCES

Month	Electricity consumption, MWh	Mean electricity price, EUR/MWh	Electricity cost, EUR
January	1 016.0	76.11	77 320
February	1 005.9	57.44	57 784
March	1 096.4	61.69	67 634
April	1 106.5	55.35	61 249
May	1 458.6	52.08	75 962
June	1 317.7	60.55	79 795
July	1 358.0	50.19	68 155
August	1 408.3	33.71	47 472
September	1 156.8	43.02	49 770
October	1 187.0	68.74	81 596
November	1 046.1	75.89	79 395
December	1 096.4	69.08	75 747
TOTAL	**14 253.6**	**57.66**	**821 878**

2.4. Revenue estimation

Revenue calculation was based on arbitrage system data acquired for year 2024 using Day-Ahead-Market data. Calculation methodology was similar to energy consumption, monthly energy production was estimated, as well as mean electricity prices based on the data acquired for Day-Ahead-Market data for year 2024. Calculations were carried out for each of the analysed systems.

Table 44. Electricity production revenue - PSH

Month	Electricity production, MWh	Mean electricity price, EUR/MWh	Revenue, EUR
January	736.6	111.49	82 129
February	637.4	96.76	61 675
March	673.5	99.80	67 216
April	625.4	107.42	67 180
May	682.5	115.82	79 047
June	622.4	168.42	104 818
July	577.3	194.78	112 443
August	637.4	182.45	116 294
September	640.4	179.02	114 648
October	685.5	177.76	121 855
November	676.5	198.36	134 189
December	670.5	162.71	109 093
TOTAL	**7 865.3**	**148.83**	**1 170 587**

Table 45. Electricity production revenue – A-CAES

Month	Electricity production, MWh	Mean electricity price, EUR/MWh	Revenue, EUR
January	2 225.3	110.64	246 205
February	2 160.4	93.34	201 650
March	2 376.5	99.70	236 932
April	2 376.5	104.47	248 267
May	3 132.6	118.88	372 403
June	2 830.2	181.58	513 891
July	2 916.6	204.86	597 481
August	3 024.6	193.92	586 536
September	2 484.5	175.41	435 819
October	2 484.5	175.46	435 926
November	2 268.5	191.51	434 440
December	2 376.5	162.00	384 994
TOTAL	**30 656.7**	**153.13**	**4 694 542**

Table 46. Electricity production revenue - CCES

Month	Electricity production, MWh	Mean electricity price, EUR/MWh	Revenue, EUR
January	669.9	110.51	74 030
February	650.4	91.56	59 551
March	715.4	99.85	71 439
April	715.4	105.22	75 276
May	943.1	119.38	112 587
June	852.0	182.86	155 800
July	878.0	208.64	183 191
August	910.6	195.22	177 762
September	748.0	179.91	134 569
October	748.0	177.83	133 010
November	682.9	191.36	130 680
December	715.4	159.30	113 968
TOTAL	**9 229.2**	**154.06**	**1 421 863**

For the prezented OPEX and revenue estimation, a summary of all revenues and costs for the analysed varainds was carried out.

Table 47. OPEX and revenue calculation for analysed variants

Parameter	Variant 1	Variant 2
OPEX		
Fixed O&M, EUR	1 680 857	1 392 176
Variable O&M, EUR	67 825	37 216
Total O&M, EUR	1 748 682	1 429 392
Electricity consumprion, EUR	3 615 080	1 717 522
Total OPEX, EUR	5 363 762	3 146 914
Revenue		
Electricity production, EUR	5 865 129	2 592 450
Income		
Total income, EUR	501 367	-554 464

Results show that for the Variant 1, total income of 501 367 EUR/year was calculated, while in the case of Option 2, OPEX – including O&M costs and electricity consumption costs – exceeds revenues by 554 464 EUR/year.

2.5. Economic performance indicators calculation

The calculation of economic efficiency indicators was based on assumptions based on data presented in the NETL guidelines, publicly available macroeconomic data, and our own assumptions.

Table 48. Global economic assumptions

Assumption	Value	Source
Capital expenditure period	3 years	Based on NETL guidelines
Distribution of TOC over the Capital Expenditure period	10%, 60%, 30%	Based on NETL guidelines
Operational period	30 years	Based on NETL guidelines
Income tax rate	19%	Based on average CIT value
Capital depreciation	20 years	Based on NETL assumptions, assumed straight line depreciation
Escalation of costs and revenues	0% real	Based on NETL assumptions
Escalation of labour cost	2 % real	The long-term average annual dynamics of labour cost was adopted in accordance with the guidelines for the use of uniform macroeconomic indicators[11]
Financial structure, debt/equity	50%/50%	Assumed based on own data
Cost of debt	6%	Assuming average value of WIBOR 6M at 4% + 2% margin
Cost of equity	10%	Based on NETL assumptions
r, discount rate	ATWACC	Assumed ATWACC value
Debt repayment period	30 years	Equal to operational period, based on NETL assumptions

[11] https://www.gov.pl/web/finanse/wytyczne-sytuacja-makroekonomiczna, access 29.06.2026

Calculation of after-tax weighted average cost of capital was performed using formula:

$$ATWACC = \%Equity * r_{Equity} + \%Debt * r_{Debt} * (1 - ETR)$$

Where:

$\%_{Equity}$, $\%_{Debt}$ – financial structure of the project, assumed 50%/50%

r_{equity} – cost of equity, 10%

r_{debt} – cost of debt, 6%,

ETR – effective tax rate, assumed CIT value of 19%.

Calculated ATWACC value is 7.43%.

2.6. Results of calculations

Based on the results of CAPEX, OPEX and income estimation, economic performance indicators values were calculated.

NPV [EUR] – Net Present Value – The NPV of a project is defined as the value obtained by discounting, at a constant rate and separately for each year, the differences between cash inflows and outflows occurring over the project's entire life. The NPV indicates only positive inflows or positive benefits from the project.

IRR [%] – Internal Rate of Return – The Internal Rate of Return (IRR) is the discount rate at which the present value of cash outflows equals the present value of cash inflows. In other words, it is the discount rate at which the net present value (NPV) of the project equals zero, meaning that the discounted project benefits are equal to the discounted investment costs. IRR can be interpreted as the annual net rate of return on the invested capital or, alternatively, as the maximum annual borrowing cost (after tax) that the project can sustain while remaining economically viable.

SPBT [years] – Simple Payback Time – The payback period, also known as the payback period, is defined as the period required to recoup the initial investment expenditure through a return on the project's cumulative net cash balances. Using SPBT is useful when rapid technological change is expected in a given industry, particularly when the project's technological life cycle is shorter than its technical life cycle. The payback period method focuses primarily on the initial phase of the operational life and does not represent the investment's performance beyond the payback period.

Table 49. Economic performance indicators

Parameter	Variant 1	Variant 2
NPV, mln EUR	-210,3	-193,3
IRR, %	-12,42	-
SPBT, years	-	-

Calculation of economic performance inditactors shows that for the analysed cases, storage of electricity is not feasible. For Variant 1 it shows that IRR indicator value should be negative to achieve NPV of 0, while for Variant 2 IRR value was not calculated due to higher OPEX costs than calculated revenues.

2.7. Levelized cost of Energy calculation

LCOH calculations were performed based on the LCOE (Levelized Cost of Energy) calculation methodology according to the Cost Estimation Methodology for NETL Assessments of Power Plant Performance[12] and in the article[13]. The following Equation was used to calculate the LCOE index value. All calculations were performed in the nominal approach:

$$LCOH = LCC + LOM + LEC$$

where:

LCC – Levelized cost of capital,

LOM – Levelized annual O&M expenses,

LEP – Levelized annual electricity expenses.

LCC and LOM were obtained according to equations (10)-(15):

$$LCC = TOC * FCR$$

$$FCR = \frac{CRF}{(1 - ETR)} - \frac{ETR * D}{(1 - ETR)}$$

$$CRF = \frac{ATWACC * (1 + ATWACC)^y}{(1 + ATWACC)^y - 1}$$

$$D = CRF * \sum_{n=1}^{z} \frac{d_n}{(1 + ATWACC)^n}$$

$$LOM = AOM * \frac{ATWACC * (1 + ATWACC)^y}{(1 + ATWACC)^y - 1} * \frac{1 - \left[\frac{(1 + i)}{(1 + ATWACC)}\right]^y}{ATWACC - i}$$

where:

TOC – Total overnight cost,

FCR – Fixed charge rate,

CRF – Capital recovery factor,

ETR – effective tax rate,

ATWACC – nominal after tax weighted average cost of capital,

D – present value of tax depreciation expense,

d_n – tax depreciation fraction in year n,

y – number of operating years,

z – number of years of depreciation,

AOM – annual O&M costs,

[12] Cost Estimation Methodology for NETL Assessments of Power Plant Performance, Quality Guidelines for Energy System Studies, NETL-PUB-22580, February 2021.
[13] Chmielniak, T.; Iluk, T.; Stepien, L.; Billig, T.; Sciazko, M. Production of Hydrogen from Biomass with Negative CO2 Emissions Using a Commercial-Scale Fluidized Bed Gasifier. Energies 2024, 17, 5591

i – assumed annual O&M escalation rate, assumed based on the long-term average annual dynamics of CPI index adopted in accordance with the guidelines for the use of uniform macroeconomic indicators[14].

In the case of determining the LEC value, for the analysed variants it was assumed that LEC is calculated for the consumed electricity, accroding to the same formula as for LOM calculation.

$$LEC = AEC * \frac{ATWACC * (1 + ATWACC)^y}{(1 + ATWACC)^y - 1} * \frac{1 - \left[\frac{(1 + i)}{(1 + ATWACC)}\right]^y}{ATWACC - i}$$

Where:

AEP – annual electricity expenses.

The numerical assumptions adopted for the calculations and the calculated unit indicators of investment, operating and fuel costs are summarized in Table 48, and results are shown in Table 49.

Table 50. LCOE calculation results

Parameter	Variant 1	Variant 2
LCC, EUR/MWh	570.83	1 119.72
LOM fix, EUR/MWh	56.25	104.98
LOM var, EUR/MWh	2.27	2.81
LEC, EUR/MWh	120.97	129.51
LCOE, EUR/MWh	750.32	1 357.01

Calculation shows that levelized cost of elestricity production is very high and reaches 750 EUR/MWh for Variant 1 and over 1357 EUR/MWh for Variant 2. Main component of the LCOE is the Levelized cost of capital, accounting for over 76% of LCOE in variant 1 and 82,5% of LCOE in Varint 2.

2.8. Levelized cost of energy calculation

In this part of the project additional case analysis was performed, invetigating impact of non-repayable financing on performance indicators and LCOE. 2 cases were adopted for the analysis:

- Case 1 – acquisition of non-repayable financing for 50% of total overnight costs,
- Case 2 – acquisition of non-repayable financing for 80% of total overnight costs.

All other assumptions were similar to the base scenario analysis. Financing of the remainig part of the CAPEX was assumed to be 20% equity and 80% low-interest loan with preferential rates of 2,5%. Calculation of ATWACC was also performed for new conditions:

$$ATWACC = \%\mathrm{Grant} * r_{Grant} + \%Equity * r_{Equity} + \%Debt * r_{Debt} * (1 - ETR)$$

[14] https://www.gov.pl/web/finanse/wytyczne-sytuacja-makroekonomiczna, access 29.06.2026

Where:

$\%_{Equity}$, $\%_{Debt}$, $\%_{Grant}$ – financial structure of the project, 50% grant, 10% equity, 40% debt for Case 1 and 80% grant, 4% equity, 16% debt for Case 2,

r_{Equity} – cost of equity, 10%

r_{Debt} – cost of debt, 2,5%,

r_{Grant} – cost of grant, 0%

ETR – effective tax rate, assumed CIT value of 19%.

New calculated ATWACC value was 1.81% for Case 1 and 0.72% for Case 2.

Results of the Case calculations were shown in Tables X and X.

Table 51. Case analysis – Case 1 (50% grant financing)

Parameter	**Variant 1**	**Variant 2**
CAPEX analysis		
Total overnight cost (TOC), EUR	234 650 809	204 252 422
Grant, EUR	117 325 405	102 126 211
Equity, EUR	23 465 081	20 425 242
Low-income debt, EUR	93 860 324	81 700 969
Economic performance indicators		
NPV, mln EUR	-103.9	-112,3
IRR, %	-9.95	-
SPBT, years	-	-
LCOE calculation		
LCC, EUR/MWh	137.66	270.02
LOM fix, EUR/MWh	61.78	115.31
LOM var, EUR/MWh	2.49	3.08
LEC, EUR/MWh	132.87	142.25
LCOE, EUR/MWh	334.80	530.66

Table 52. Case analysis – Case 2 (80% grant financing)

Parameter	**Variant 1**	**Variant 2**
CAPEX analysis		
Total overnight cost (TOC), EUR	234 650 809	204 252 422
Grant, EUR	187 720 647	163 401 938
Equity, EUR	9 386 032	8 170 097
Low-income debt, EUR	37 544 129	32 680 388
Economic performance indicators		
NPV, mln EUR	-33.7	-55.2
IRR, %	-6.25	-
SPBT, years	-	-
LCOE calculation		
LCC, EUR/MWh	46.09	90.41
LOM fix, EUR/MWh	63.01	117.61
LOM var, EUR/MWh	2.54	3.14
LEC, EUR/MWh	135.52	145.10
LCOE, EUR/MWh	247.17	356.26

Results show, that acquiring non-repayable financing in form of a grant results in a significant decrease of LCOE in Case 1 and further decrease in Case 2. However, even in Case 2, economic performance indicators are still negative, thus showing that investment is not feasible.

3. Summary

Last part of the Deliverable 7.1 includes a financial analysis of the analysed variants, including determination of estimated totla overnight costs, estimated OPEX and revenue, determination of the economic performance indicators and calculation of LCOE.

CAPEX analysis has shown that Variant 1 is slightly more expensive than Variant 2. The results also revealed very high specific costs. This is due to the assumption of a high power generation relative to the storage capacity, which was adopted because of the short operating times of the HESS unit during the day (3/5 and 4/8h).

Table 53. Total overnight cost (TOC) for analysed Variants

Costs Area	**Variant 1**	**Variant 2**
Bare erected cost (BEC)	**148 717 334**	**130 336 185**
Contracting Strategy and EPC Contractor Services	22 286 339	19 529 167
Engineering, procurement and construction cost (EPCC)	**171 003 673**	**149 865 352**
Process Contingency	3 025 835	1 489 468
Project Contingency	25 650 551	22 479 803
Total plant cost (TPC)	**199 680 059**	**173 834 623**
Preproduction (Start-Up) Costs	998 400	869 173
Inventory Capital	3 990 341	3 473 432
Other Owner's Costs	29 952 009	26 075 193
Total overnight cost (TOC)	**234 620 809**	**204 252 422**

OPEX and revenue analysis showed that main component of OPEX costs is the electricity consumption cost. Revenue is depending fully on the market prices of the electricity, while significant part of the OPEX is also fixed O&M costs, unaffected by the plant's availability.

Table 54. OPEX and revenue calculation for analysed variants

Parameter	Variant 1	Variant 2
OPEX		
Fixed O&M, EUR	1 680 857	1 392 176
Variable O&M, EUR	67 825	37 216
Total O&M, EUR	1 748 682	1 429 392
Electricity consumprion, EUR	3 615 080	1 717 522
Total OPEX, EUR	5 363 762	3 146 914
Revenue		
Electricity production, EUR	5 865 129	2 592 450
Income		
Total income, EUR	501 367	-554 464

Calculation of economic performance inditactors shows that for the analysed cases, storage of electricity is not feasible. For Variant 1 it shows that IRR indicator value should be negative to achieve NPV of 0, while for Variant 2 IRR value was not calculated due to higher OPEX costs than calculated revenues.

Table 55. Economic performance indicators

Parameter	Variant 1	Variant 2
NPV, mln EUR	-210,3	-193,3
IRR, %	-12,42	-
SPBT, years	-	-

LCOE calculation was performed based on the LCOE (Levelized Cost of Energy) calculation methodology according to the Cost Estimation Methodology for NETL Assessments of Power Plant Performance. It consisted of 3 different cost components: levelized capital cost (LCC), levelized O&M costs (LOM) and levelized electricity costs (LEC). Analysis has shown that main component of the LCOE was the Levelized cost of capital, accounting for over 76% of LCOE in variant 1 and 82,5% of LCOE in Varint 2.

Table 56. LCOE calculation results

Parameter	Variant 1	Variant 2
LCC, EUR/MWh	570.83	1 119.72
LOM fix, EUR/MWh	56.25	104.98
LOM var, EUR/MWh	2.27	2.81
LEP, EUR/MWh	120.97	129.51
LCOE, EUR/MWh	750.32	1 357.01

Analysis shows that the arbitrage system prices determine the effectiveness of the system. Assuming one full cycle per day, the system can maximize the income based on the Day-Ahead-Market prices acquired, but according to the LCOE analysis, the maximization of the arbitrage system revenue for 1 cycle per day is insufficient to achieve a positive financial results. Due to the high share of capital costs in the LCOE calculation, it is recommended to obtain additional financial support in form of funding for the plant construction, in order to reduce capital costs component and thereby improve the LCOE.

Case analysis for acquisition of non-repayable financing in form of a grant for 2 levels of financing was performed (Case 1 – 50%, Case 2 – 80%). Results show, that acquiring non-repayable financing in form of a grant results in a significant decrease of LCOE in Case 1 and further decrease in Case 2. However, even in Case 2, economic performance indicators are still negative, thus showing that investment is not feasible.

Table 57. Case analysis results of LCOE calculation

Parameter	Variant 1	Variant 2
LCOE – base scenario, EUR/MWh	750.32	1 357.01
LCOE – Case 1, EUR/MWh	334.80	530.66
LCOE – Case 2, EUR/MWh	247.17	356.26