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EXECUTIVE SUMMARY

Thermal energy storage allows the ALLEGRO gas-cooled fast reactor demonstrator to follow electricity prices without modulating the reactor. The analysis reported in this deliverable shows that the concept is technically feasible with largely mature components, subject to development of the charging heat exchanger, but that its economic case rests on a deliberately oversized power block rather than on the storage itself.

The power conversion chain was designed first. From the 75 MWth primary heat source, a secondary nitrogen Brayton cycle delivering 11.2 MW at 15.2% efficiency is coupled to a tertiary steam cycle producing 18.8 MW at 38.3% with live steam at 10 MPa and 545 °C, giving 30 MW net at an overall plant efficiency of 40.1%. Reaching 545 °C required splitting the heat transfer from the secondary to the tertiary circuit into separate high- and low-temperature exchangers, an arrangement that additionally recovers 12.1 MW of heat that would otherwise be rejected.

Thermal energy storage is the natural choice for this application, since heat is both the input and the output of the store and no conversion between energy forms is involved; with an appropriate operating regime, heat-to-heat efficiency can exceed 90%. Following a review of sensible, latent and thermochemical options, solid-media storage was set aside because its air-based heat transfer loop is poorly suited to the high charging and discharging powers required, and latent-heat storage because it does not yet offer a sufficiently reliable solution at the temperatures involved. A two-tank molten nitrate salt system, mature and widely deployed in concentrated solar power plants, was therefore selected as the reference solution.

The reference design combines two molten-salt systems in series, each with its own hot and cold tank: a high-temperature section using Solar Salt for evaporation and superheating, and a low-temperature section using HITEC for feedwater preheating. This allows live steam of up to 545 °C to be raised from storage, matching the design value of the tertiary cycle, at the cost of four tanks instead of two. The current estimate is based on 168 MWh of storage — 135 MWh in the Solar Salt section and 33 MWh in the HITEC section — requiring about 1380 t of Solar Salt and 510 t of HITEC. A simpler single-salt alternative uses Yara Most between 170 °C and 500 °C in only two tanks: storing approximately 730 MWh would require some 2700 m³ of salt (about 5200 t) in two tanks of 2000 m³. Because the hot tank is limited to 500 °C, however, steam raised from storage would be cooler than the 545 °C design value.

An estimate based on supplier quotations places the capital cost of the reference two-salt system, rated at about 50 MW in charge and discharge and including the charging heat exchangers, at about 22.5 M€. For the single-salt alternative, a literature-based estimate gives 50–70 M€ for 730 MWh; this figure should be regarded as a lower bound, since it does not include the nitrogen-to-salt charging heat exchangers, and current supplier data indicate complete-system costs of 100–200 \$/kWhth and salt prices of about 2 \$/kg, well above older literature values. The higher specific cost of the reference system (about 134 €/kWhth, against roughly 70–95 €/kWhth for the alternative) underlines the large uncertainty in current CAPEX figures. Neither estimate covers the technology qualification, licensing and safety demonstration required for deployment on the nuclear island, which are expected to add further costs that cannot yet be quantified. The charging heat exchanger, a non-standard gas-to-salt unit not yet demonstrated at large scale, is the principal technical development need. Against these challenges stand an expected service life of 30 years or more, low salt degradation and a limited additional operating cost in a plant that is already continuously staffed. Demonstrating that the storage cannot compromise reactor heat removal under any operating or accident condition will require a dedicated safety assessment and licensing effort.

Optimising daily dispatch against day-ahead prices in Poland, Hungary, the Czech Republic and Slovakia shows that price-following operation clearly outperforms consumption following in an energy-only market. Multi-cycle scheduling beats single-cycle scheduling in every market analysed, but by only 1% to 5% — between 0.8 and 2.7 k€ per day, an indicative 0.3 to 1.0 M€ per year — a

margin that does not obviously justify its six or more daily mode switches and its greater exposure to price-forecast error.

The dominant design consequence is that the steam turbine must be rated for the peak discharge condition and not for the steady-state design point: approximately 33 MW is required, 1.75 times the 18.8 MW design output. The machine then operates as a two-point unit, at 98–110% of rating during discharge and 28–40% during charging, and never at its nominal point. Priority next steps are a load-dependent cycle efficiency characteristic, a full levelized cost analysis, the charging heat exchanger design and a nuclear safety assessment of the coupled system.

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1 INTRODUCTION

This document summarises the work performed during the TREASURE project on the implementation of thermal energy storage in the power conversion system of a gas-cooled fast reactor. Because storage can only be integrated into a cycle that is itself well defined, the power conversion options were analysed first, building on the Brayton-cycle efficiency studies carried out in preceding projects.

The TREASURE project addresses the design of a gas-cooled fast reactor demonstrator based on the ALLEGRO concept. A reactor of this type operates most safely and most economically at constant thermal power, yet the electricity markets into which it would sell are increasingly shaped by variable renewable generation: photovoltaic infeed depresses midday prices, in some markets to essentially zero, while steep morning and evening ramps concentrate value into a few hours of the day. A plant that cannot shift its output in time is obliged to sell a flat profile into a volatile price curve, and therefore realises less than the average market value of the energy it produces.

Thermal energy storage offers a way to resolve this conflict without modulating the reactor itself [1]. Heat is diverted from the power conversion system into a storage medium during hours of low electricity value and returned to the steam cycle during the price peaks, so that the reactor continues to see a constant load while the electrical output of the plant follows the market signal. This deliverable examines whether such a concept is technically sound and economically worthwhile for the ALLEGRO power conversion chain, and what it implies for the sizing of the components involved.

The document follows the design sequence. Section 2 analyses the secondary Brayton cycle and the safety considerations that bound it. Section 3 develops the tertiary steam cycle and fixes its live steam parameters. Section 4 surveys the available storage technologies, selects the two-tank molten-salt solution as the reference, and proposes a reference design together with an indicative cost. Section 5 derives the governing equations of storage operation, compares consumption-following with price-following dispatch, optimises single-cycle and multi-cycle schedules against day-ahead prices in four Central European markets, and examines the consequences for steam turbine rating. Section 6 draws the conclusions and identifies the remaining work.

2 Power conversion analysis

This section presents the analysis of the power conversion system proposed for the 75 MW ALLEGRO demonstrator. The system is built around an intermediary circuit — a closed nitrogen Brayton cycle, hereafter referred to as the secondary circuit — interposed between the helium-cooled primary circuit and a tertiary steam Rankine cycle. The concept originates from the KOBRA project [1], where the secondary circuit was designed primarily to fulfil a safety role: to provide a source of residual power for the primary circuit blowers, maintaining coolant circulation even in the event of a station blackout. Beyond this safety function, the architecture offers a second, operational capability. By interposing a Thermal Energy Storage (TES) system between the secondary and tertiary circuits, the plant can decouple electricity generation from heat generation, enabling variable electrical output that follows grid demand while the reactor operates at a constant thermal power of 75 MW. The section covers the general layout of the conversion system, the selection of its operating pressures with respect to nuclear safety constraints, and the optimisation of the secondary and tertiary circuits; the underlying parametric studies, performed on a thermodynamically equivalent scaled cycle, are reported in [1] and their optimal parameters apply directly to the unit analysed here.

2.1 General layout

The proposed design introduces an intermediary system — effectively a new secondary circuit — positioned between the primary circuit and the tertiary steam cycle. The secondary circuit is a closed Brayton cycle using nitrogen as the working fluid, with no regeneration and no compressor intercooling. Nitrogen is compressed and subsequently heated in the primary–secondary heat exchanger, where it absorbs the 75 MW thermal output of the reactor from the primary helium, which cools from 850 °C to 400 °C at 7 MPa (Table 1). The hot nitrogen then expands in a gas turbine mounted on a common shaft with the compressor. The energy of the cycle is utilised in three ways. First, the net power output of the gas turbine remains available to drive the primary circuit blowers, fulfilling the safety function described above. Second, the turbine exhaust, which leaves at a temperature close to 570 °C, constitutes a high-grade heat source and is transferred to the tertiary circuit in a high-temperature heat exchanger, where superheated steam is generated for a conventional Rankine cycle. Third, the residual low-temperature heat of the nitrogen stream is recovered in a low-temperature heat exchanger for feedwater heating before the nitrogen returns to the compressor inlet, maximising overall heat utilisation. The layouts of the secondary and tertiary circuits, together with their fixed parameters, are shown in Figure 1.

Table 1 Fixed parameters of the ALLEGRO primary circuit at the primary–secondary heat exchanger (helium side).

	Pressure [MPa]	Temperature [deg C]
HEX inlet	7	850
HEX outlet	7	400

The first objective of the analysis is to optimise the design and operating parameters of both the secondary and tertiary systems — in particular the operating pressure level and pressure ratio of the secondary Brayton cycle, and the steam admission pressure of the tertiary Rankine cycle — with respect to net power, overall efficiency, and nuclear safety constraints

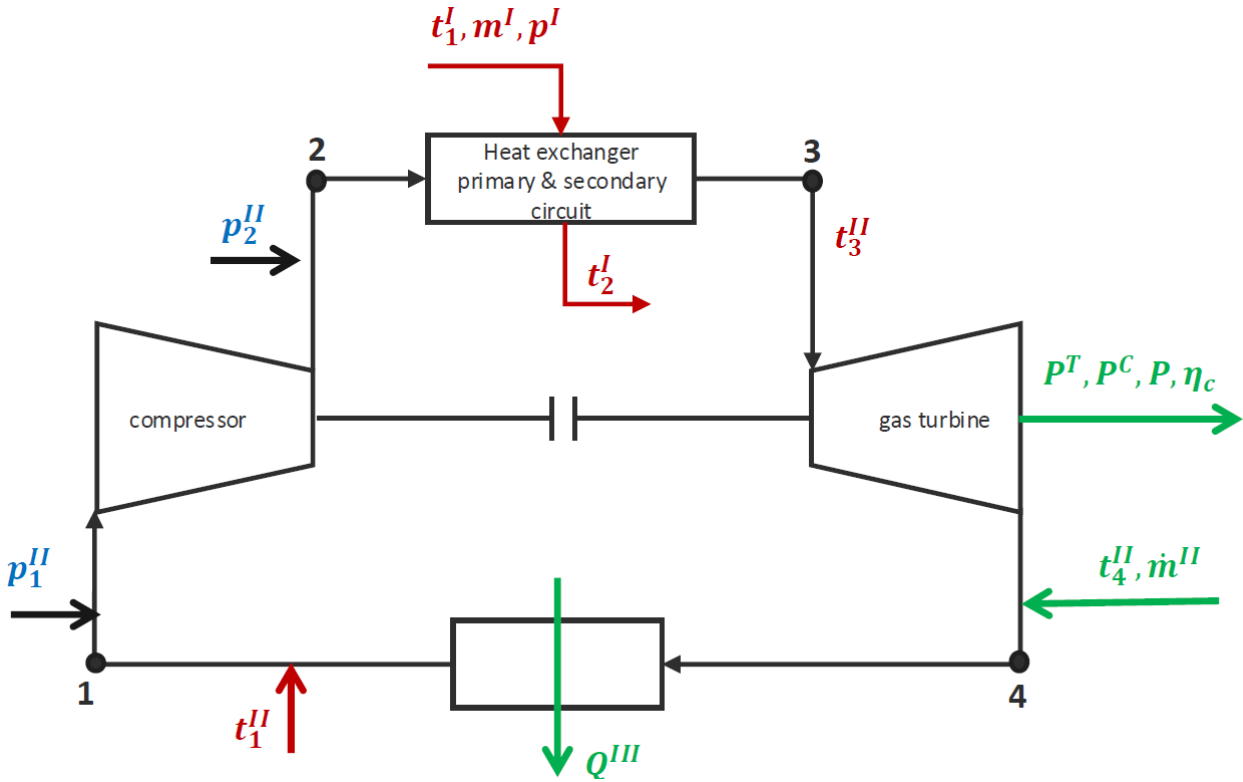


Figure 1 Layout of the secondary nitrogen Brayton cycle coupled to the primary helium circuit, with fixed parameters of both circuits.

2.2 Starting point and safety considerations

The analysis takes as its fixed boundary condition the primary circuit of the ALLEGRO demonstrator in its high-temperature configuration. The primary helium parameters at the interface with the secondary circuit — the primary–secondary heat exchanger — are summarised in Table 1 and are not subject to change in any of the studies presented below.

The initial working conditions of the secondary circuit were adopted from the preceding KOBRA project [1], in which the nitrogen Brayton cycle was originally designed and dimensioned as a safety system providing power to the primary circuit blowers. The KOBRA design operated at a high pressure level, with a compressor inlet pressure of 7.5 MPa and outlet pressure of 22.5 MPa, a compressor inlet temperature of 60 °C, a turbine inlet temperature of 830 °C, and a resulting turbine outlet temperature of 608 °C (Table 2).

Table 2 Initial (high-pressure) secondary circuit working conditions inherited from the KOBRA project (nitrogen side).

	Pressure [MPa]	Temperature [deg C]
HX inlet	22.5	60
HEX outlet (GT inlet)	22.5	830
GT out	7.5	608

The high-pressure secondary circuit inherited from KOBRA offers the highest cycle efficiency, but it presents two significant issues when assessed from the perspective of nuclear safety. First, since the secondary pressure (up to 22.5 MPa) substantially exceeds the primary circuit pressure of 7 MPa,

any leak in the primary–secondary heat exchanger would result in high-pressure nitrogen ingress into the primary circuit. Unexpected heating of the core is unlikely, since the secondary medium is cooler than the primary coolant and its temperature would decrease further as it expands into the primary circuit. The more likely consequence is over-pressurisation of the primary system, which could cause failure of primary circuit components and prevent the injection of low-temperature nitrogen from the dedicated safety system. The ingress could also cause nitriding of surfaces, with the associated degradation of primary circuit materials, and could affect core neutronics. Second, the large pressure difference across the primary heat exchanger would require more demanding and more expensive structural materials. For these reasons, a low-pressure alternative was investigated, in which both the compressor inlet and outlet pressures are kept below the primary circuit pressure. The operating pressure of the main heat exchanger, 7 MPa, thus sets the upper limit for the pressure after the compressor, which was fixed at 6.5 MPa.

Analysis of the secondary circuit – helium parameters

Table 3 Comparison of the high-pressure and low-pressure secondary circuit designs (nitrogen side).

	Version 1		Version 2	
	Pressure [MPa]	Temperature [deg C]	Pressure [MPa]	Temperature [deg C]
HEX inlet	22.5	215	6.5	257
HEX outlet	21.9	830	5.9	830
SG inlet	8.1	608	2.27	615
SG out	7.5	60	1.67	60

For both the high-pressure and the low-pressure configuration, a parametric study of the compressor pressure ratio was performed over the range 1.2–8. In the high-pressure study the compressor inlet pressure was fixed (7.5 MPa) and the outlet pressure varied; in the low-pressure study the outlet pressure was fixed (6.5 MPa) and the inlet pressure varied. The evaluated parameters were the gas turbine power, the net power of the secondary circuit, the secondary circuit efficiency, and the turbine outlet temperature, the last of which determines the quality of the heat available to the tertiary circuit. The thermodynamic model assumes isentropic efficiencies of 90% for the turbine and 80% for the compressor, and a thermal effectiveness of 98% for the heat exchanger.

The results are compared in Figure 2 and Figure 4.

The high-pressure cycle exhibits monotonically increasing efficiency across the studied range, whereas the low-pressure cycle shows a distinct efficiency maximum at a compressor pressure ratio of 3.9. This value was therefore selected for the low-pressure design, yielding a compressor inlet pressure of 1.667 MPa at 60 °C and a turbine inlet temperature of 830 °C. The efficiency penalty relative to the high-pressure design is significant but was accepted as the cost of eliminating the nitrogen-ingress risk; moreover, the lower pressure ratio results in a higher turbine outlet temperature, which directly benefits steam generation in the tertiary circuit. The resulting working conditions of both configurations are compared in Table 3.

The selection of the compressor inlet temperature of 60 °C was verified by a dedicated sensitivity study in which the inlet temperature was varied between 60 °C and 150 °C at the selected pressure ratio: both the net power and the efficiency of the secondary circuit decrease steeply and almost linearly with increasing inlet temperature, while the turbine outlet temperature remains unaffected, confirming 60 °C as the optimal design point Figure 3. A full two-parameter optimisation over the pressure ratio (1.2–8) and compressor inlet temperature (60–200 °C) confirmed that the selected combination corresponds to the global efficiency maximum of the low-pressure cycle.

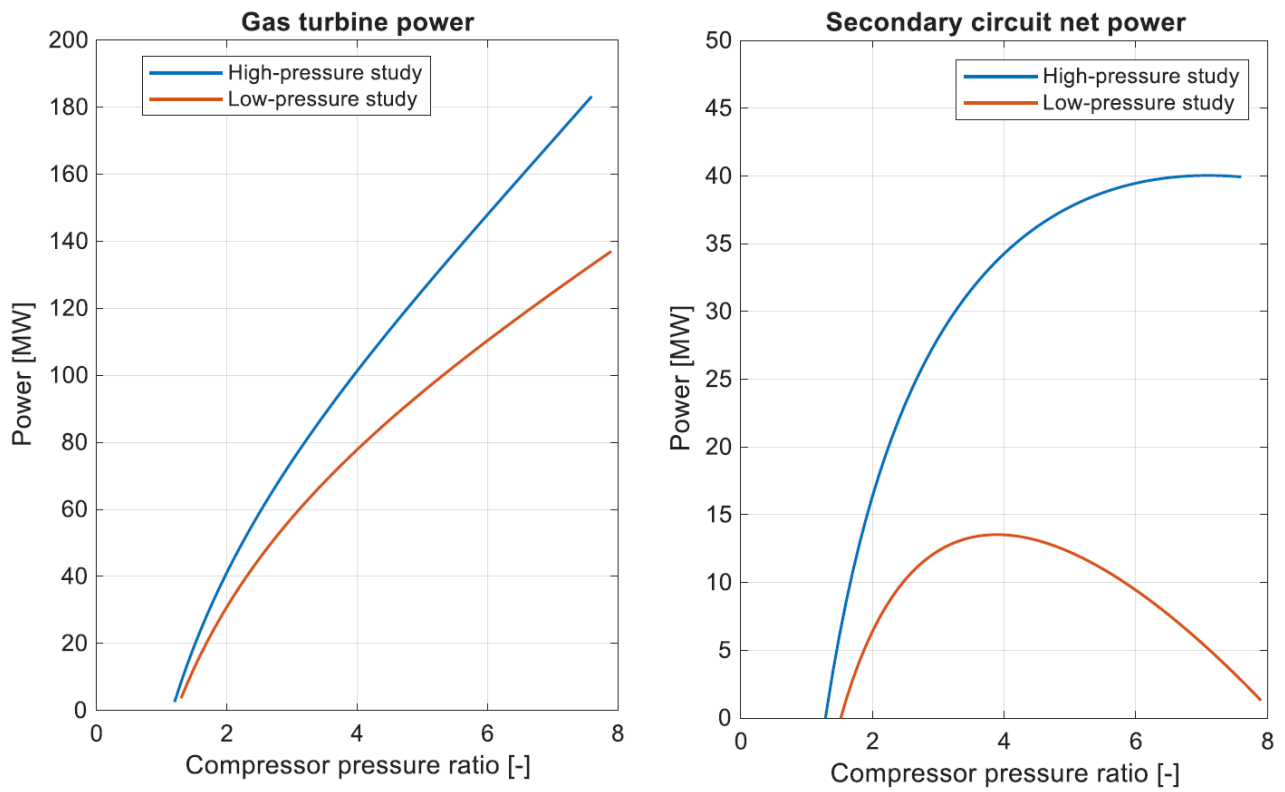


Figure 2 Gas turbine power (left) and secondary circuit net power (right) as a function of the compressor pressure ratio for the high-pressure and low-pressure configurations of the nitrogen Brayton cycle.

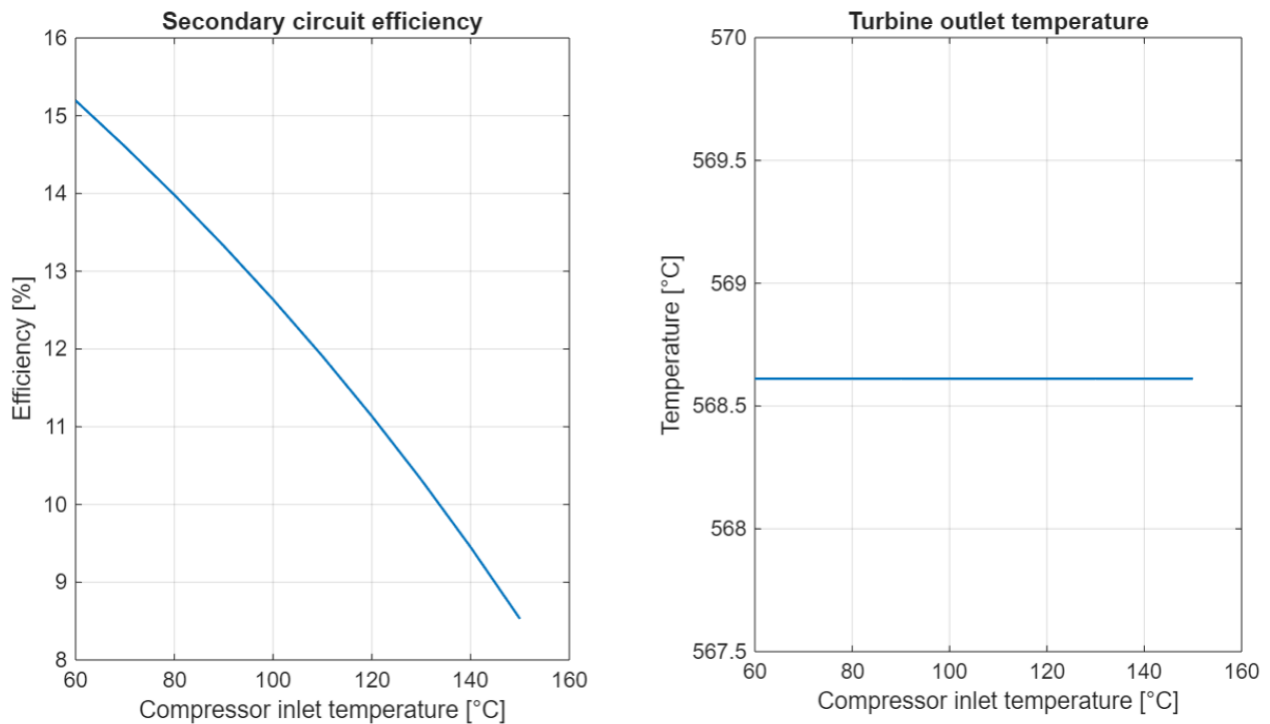


Figure 3 Secondary circuit efficiency (left) and gas turbine outlet temperature (right) as a function of the compressor inlet temperature at the selected pressure ratio of 3.9.

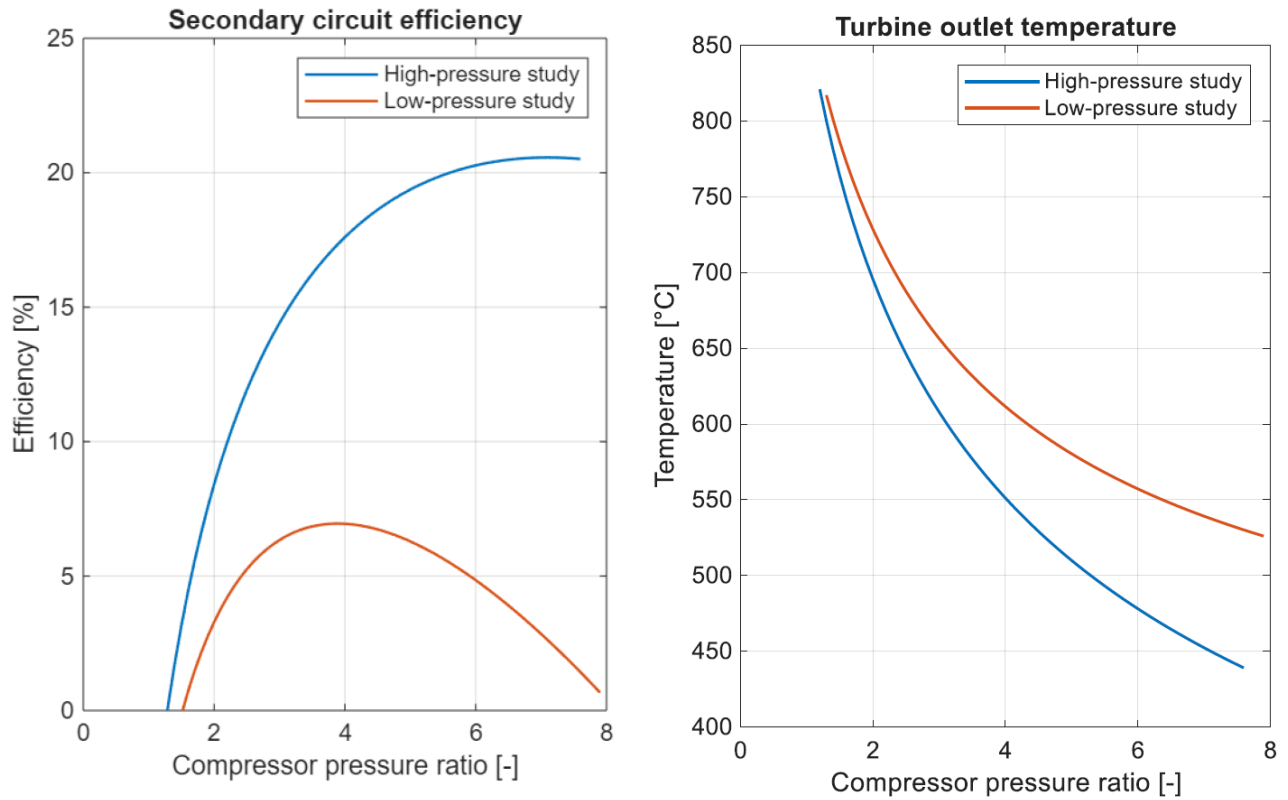


Figure 4 Secondary circuit efficiency (left) and gas turbine outlet temperature (right) as a function of the compressor pressure ratio for the high-pressure and low-pressure configurations of the nitrogen Brayton cycle.

3 TERTIARY CIRCUIT DESIGN

With the parameters of the secondary circuit established, the tertiary steam cycle can be designed. The gas turbine exhaust temperature of approximately 570 °C represents a high-grade heat source, and the main objective of the tertiary circuit design is to exploit it fully: to generate steam at conditions corresponding to a conventional steam power plant, with a live steam temperature above 540 °C (design limit 545 °C), thereby maximising the efficiency of the Rankine cycle and the net power of the plant. This objective stands in contrast to the original KOBRA steam generator conditions (steam at 400 °C), which yield an unsatisfactorily low cycle efficiency.

The analysis started from a simplified closed loop consisting of a single steam generator (heat exchanger II. & III.), a steam turbine, a condenser, and a feedwater pump, as shown in Figure 5. The fixed parameters of the cycle were a condensing temperature of 38 °C, isentropic efficiencies of 90% for the steam turbine and 85% for the pumps, and minimum temperature differences in the heat exchanger of 10 °C (approach) and 3.5 °C (pinch). The steam admission pressure was treated as the optimisation parameter and varied between 5 and 20 MPa in steps of 1 MPa, with the admission temperature maximised for each pressure within the heat exchanger constraints.

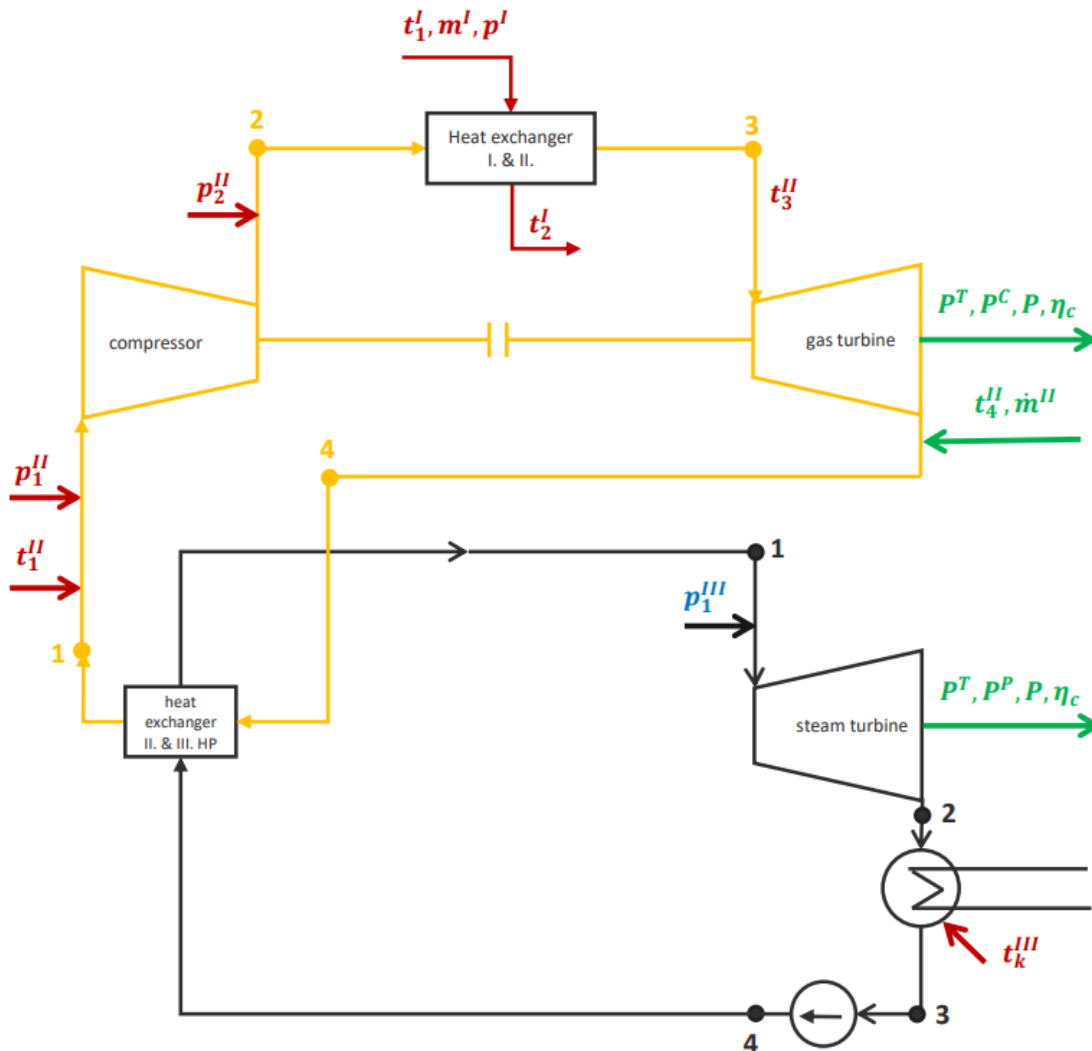


Figure 5 Simplified layout of the tertiary circuit: the secondary Brayton cycle (yellow) transfers heat to the steam cycle (black) through a single heat exchanger (II. & III.).

The results reveal the fundamental limitation of this layout. Even at the highest considered admission pressure, the achievable steam temperature remains far below the target — the pinch point of the single counter-flow heat exchanger is reached long before the steam approaches the temperature of the nitrogen stream, limiting the admission temperature to roughly 260–375 °C over the studied

pressure range (Figure 6). The corresponding overall plant efficiency remains well below the potential of the heat source. A single heat exchanger transferring the entire duty — preheating, evaporation and superheating — therefore cannot deliver steam above 540 °C at any admission pressure, and a structural change of the layout is required.

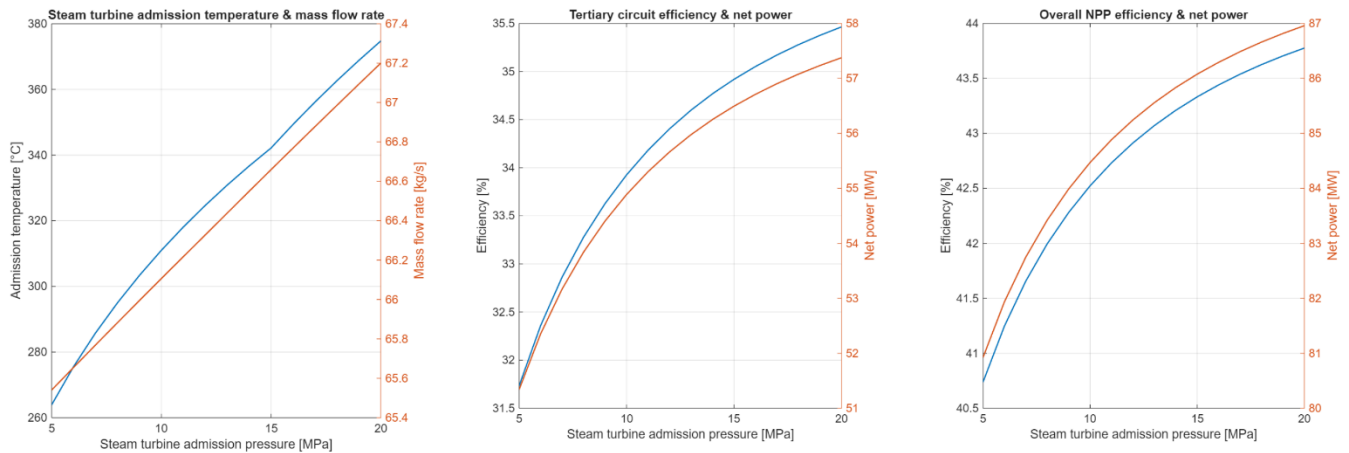


Figure 6 Simplified layout: maximum achievable steam admission temperature and steam mass flow rate as a function of admission pressure. The pinch-point limitation of the single heat exchanger prevents reaching the target temperature of 545 °C.

The final layout resolves this limitation by splitting the heat transfer from the secondary circuit into separate temperature levels, mirroring the arrangement of a realistic steam generator. The nitrogen stream leaving the gas turbine first passes through a high-temperature heat exchanger (II. & III. HT), which performs evaporation and superheating, and subsequently through a low-temperature heat exchanger (II. & III. LT), which preheats the feedwater leaving the water tank. The feedwater tank, operating at 140 °C and 1 MPa, separates the low-pressure and high-pressure sides of the feedwater train. Provision was also made for low-pressure regenerative preheating using steam extracted from the turbine; however, as shown below, this option is not used in the selected design, since the low-temperature heat available in the nitrogen stream is sufficient to cover the feedwater preheating duty.

The final layout is shown in Figure 7. This arrangement has a second benefit beyond enabling 545 °C steam: the low-temperature heat exchanger recovers an additional 12.1 MW of heat from the nitrogen stream that would otherwise be rejected to the environment, cooling the nitrogen down to conditions close to the compressor inlet temperature and thereby raising the overall heat utilisation of the plant.

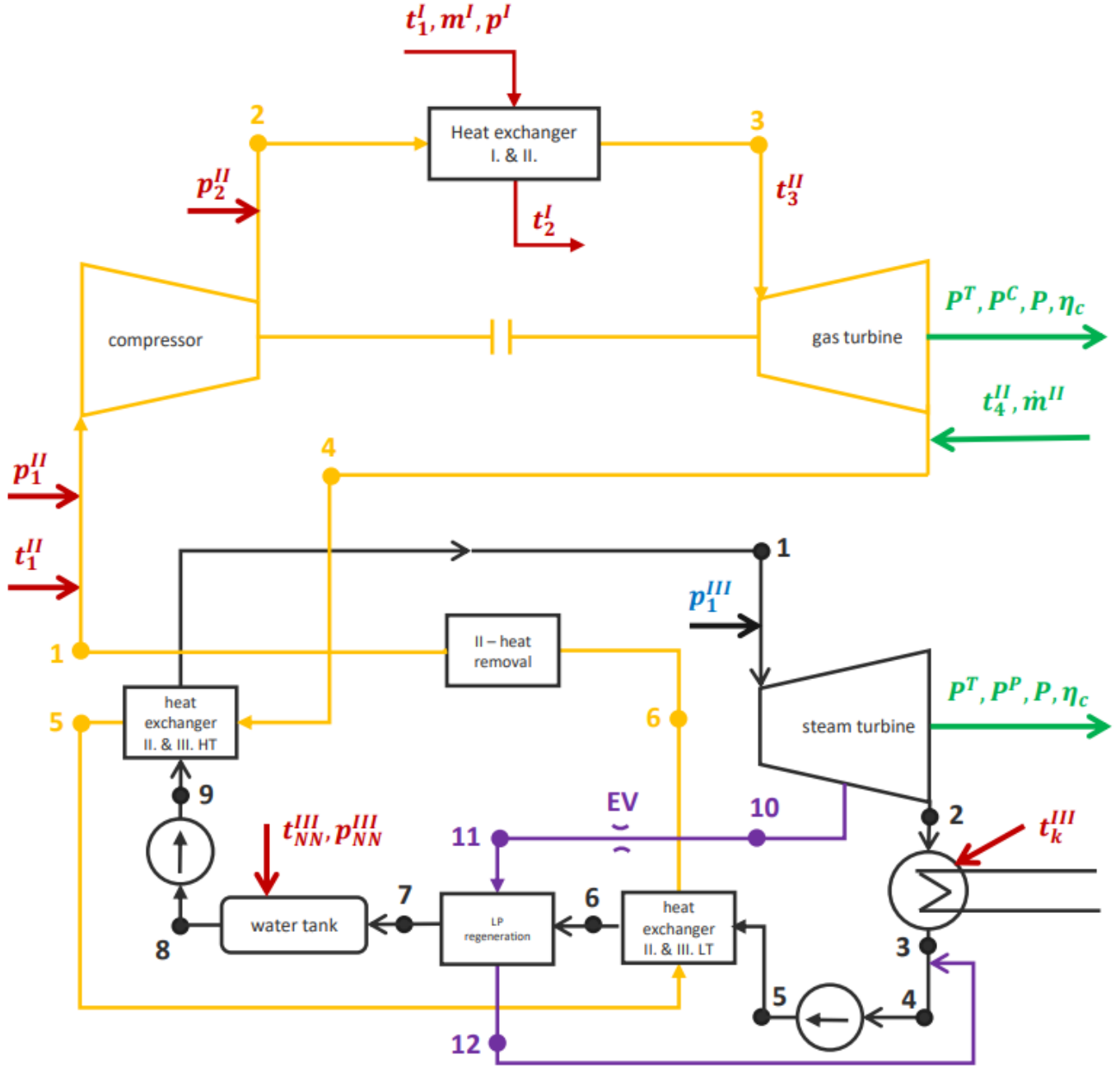


Figure 7 Final layout of the tertiary circuit with heat transfer split into high-temperature (evaporation and superheating) and low-temperature (feedwater preheating) heat exchangers. LP regeneration (greyed) is not used in the selected design.

With the final layout fixed, the steam admission pressure was again varied between 5 and 20 MPa, this time with the turbine inlet temperature fixed at 545 °C. Both the tertiary circuit efficiency and its net power increase monotonically with admission pressure (Figure 8); however, the gains flatten markedly above approximately 10 MPa. An admission pressure of 10 MPa was therefore selected as a compromise between overall plant efficiency and the practical availability of a suitable steam turbine on the market. The state points of the selected design are summarised in Table 4, and the temperature profiles of both heat exchangers, confirming that the pinch constraints are respected, are shown in Figure 9.

The selected tertiary circuit achieves an efficiency of 38.3% and a net power of 18.8 MW with a steam mass flow rate of 14.9 kg/s. Combined with the secondary circuit (11.2 MW at 15.2%), the

integrated power conversion system delivers an overall net power of 30 MW at an overall plant efficiency of 40.1%, referenced to the 75 MW thermal input.

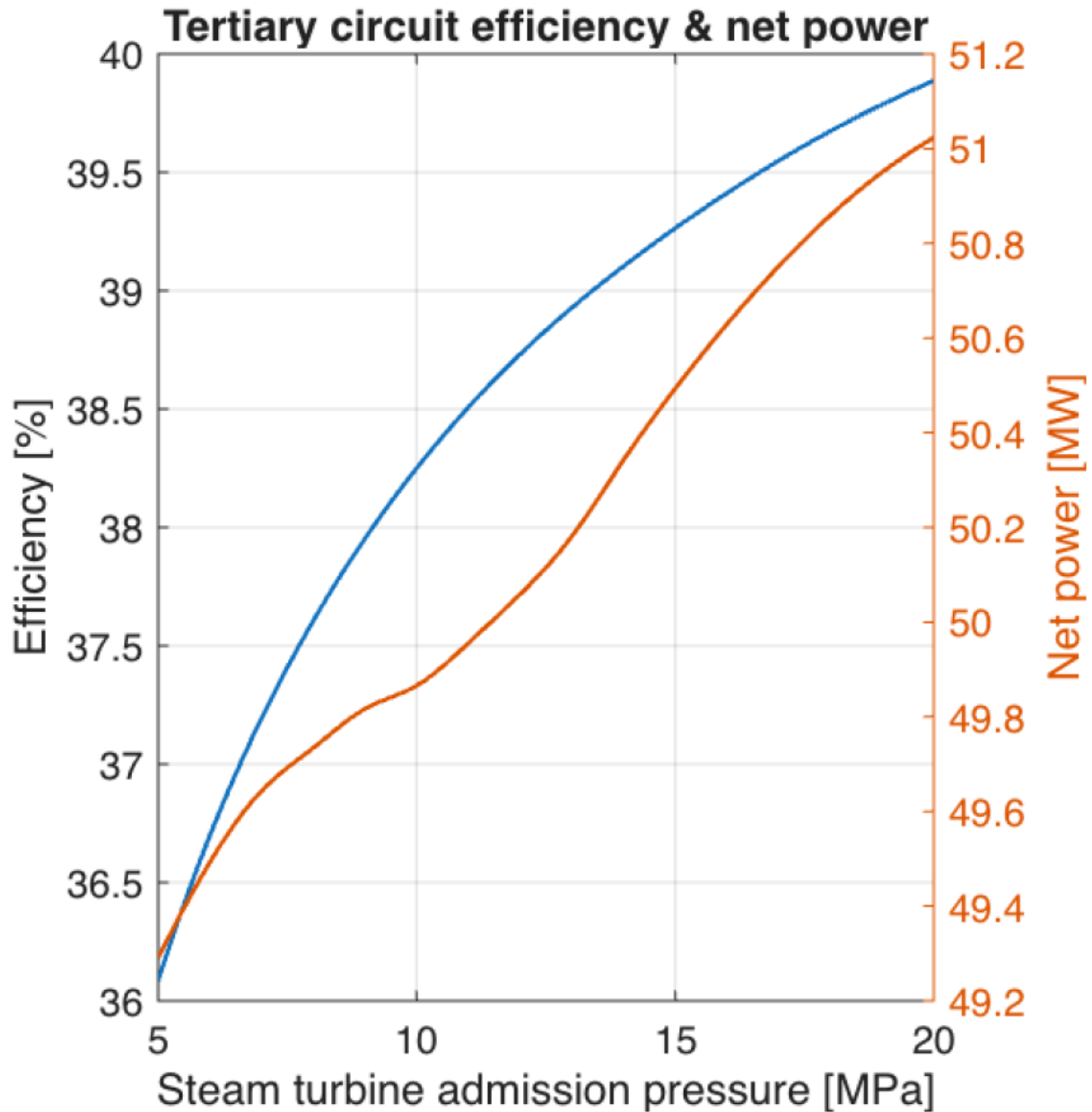


Figure 8 Tertiary efficiency and net power against admission pressure.

Table 4 State points of the selected power conversion design (75 MW_{th}, live steam 10 MPa / 545 °C) for the secondary nitrogen circuit (II.) and the tertiary water–steam circuit (III.); point numbers refer to Figure 7.

Circuit	II.	II.	II.	II.	III.	III.	III.	III.
Point	4	5	6	1	9	1	5	6
Pressure [MPa]	1.808	1.736	1.666	1.6667	11.628	10	1.3521	1
Temp.[°C]	568.3	215.1	160.8	60	141.5	545	38.1	140
Enthalpy [kJ/kg]	894.2	507.3	449.8	343.1	603.0	3489.4	160.8	589.6

Mass flow rate [kg/s]	113.0	113.0	113.0	113.0	14.9	14.9	14.9	14.9
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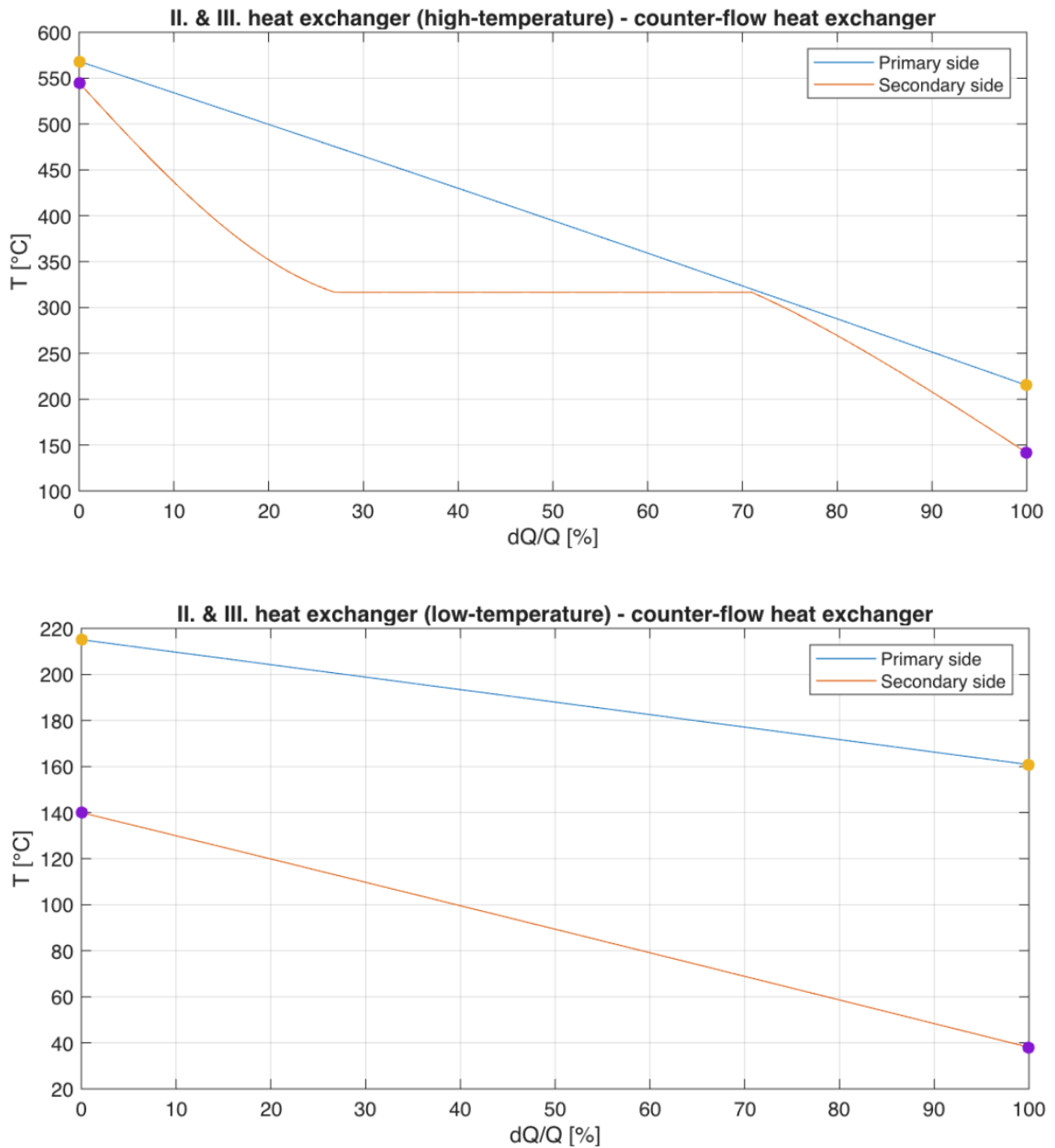


Figure 9 Temperature–heat-duty (T–Q) diagrams of the high-temperature (top) and low-temperature (bottom) II. & III. counter-flow heat exchangers for the selected design (75 MWth, 10 MPa / 545 °C); "primary side" denotes the nitrogen of the secondary circuit and "secondary side" the water/steam of the tertiary circuit.

4 THERMAL ENERGY STORAGE

4.1 Specifications

The selection of a heat storage technology depends on different parameters including the energy to be stored, the charge and discharge power, and the hot and cold temperatures available for the storage. For a nuclear application, safety considerations have also to be kept in mind. And for a heat storage connected to a power generation cycle, two performance parameters are of particular interest. The first is the round-trip efficiency (RTE), defined as the ratio of the thermal energy recovered during discharge to the energy supplied during charge; it is determined by the charging efficiency, the discharging efficiency and the thermal losses of the storage. The second is the temperature at which the stored heat is returned to the power cycle. Because a temperature difference is needed across the charging and discharging heat exchangers, the discharge temperature is always lower than the charging temperature: for example, a two-tanks storage charged at 560°C will deliver at most about 540°C during discharge. Similar performance can, however, also be achieved with Phase Change Material storage systems. For a storage connected to a power conversion cycle, the discharge temperature directly affects the cycle efficiency, so both the RTE and the discharge temperature should be maximized. A last parameter must be considered: the maturity. In the current project, a high maturity level is expected.

Concerning energy, we make the hypothesis that there will be a single steam turbine, the minimum power of which being 25% of its nominal power. The most demanding operating cycle envisaged consists of charging the storage system for 19.2 h, followed by a 4.8 h discharge period. This leads to an energy storage of around 1000 MWh thermal (for a reactor of 200 MW_{th}).

Considering power, the assumption of a charging time of 19.2h and a discharging time of 4.8h leads to a charging power of 52 MW_{th} and a discharging power of 208MW_{th}.

Considering the temperatures, the best option is to maximize the difference of temperature between the hot and the cold sources that feed the storage, to maximize the storage density and then minimize the size of the storage and its cost. Considering safety requirements, it is preferable to connect the heat storage to the tertiary circuit, as far as possible from the nuclear core, to avoid any interactions. Then the hot temperature to be considered is the outlet of the steam generator, 545°C. And the cold temperature is the lower temperature of the steam cycle, 76°C.

Thus, the ideal would be a storage with high maturity level, high thermal efficiency, able to store an amount of energy around 1000MW.h thermal with a power in charge of 52MW_{th} and a power in discharge of 208MW_{th}, for temperatures in the range 76°C-545°C.

4.2 A panorama of thermal energy solutions

Thermal energy storage is important to our system because our nuclear reactor will work at a constant load, but the electricity demand from the grid fluctuates. Thus, our only key requirement for the storage system is that it needs to be able to decorrelate the heat production in the nuclear reactor from the electricity that is sold to the energy grid in a daily cycle. Given that our power conversion block is a combined Brayton and Rankine cycle with an input temperature of around 850 °C, there are many different solutions with varying TRL, performance, and flexibility. However, all of them have something in common: the choice of the thermal energy storage conditions the operational parameters of both Brayton and Rankine cycles. Therefore, before choosing any single solution, we explored the current solutions being proposed in the TES market.

There are mainly 5 solutions proposed:

1. Sensible storage in molten salts,
2. Sensible storage in granular materials,
3. Latent solid-liquid storage,
4. Latent gas storage (liquid air or liquid CO₂), and
5. Thermochemical.

Sensible storage in molten salts is the most widely spread TES for electricity facilities, mainly operated in concentrated solar production. Depending of the choice of salt, energy can be stored up to a temperature of 565 °C. The energy sector has thousands of cumulated hours of experience with this method. It is specially indicated for large scale facilities. Integrating it into our system would allow for a flexible operation of the Rankine cycle, but it would leave the Brayton cycle to work at constant capacity.

Sensible storage in granular materials often use modular containers full of sand, crushed rocks, ceramics, or slag as the heat-storage material. The storage is charged and discharged through multiple embedded pipes using gas systems at relatively low pressures. The choice of granular materials allows for storage temperatures up to 1200 °C. This feature is extremely useful in our power conversion cycle because it would allow the flexible operation of both the Rankine and the Brayton cycles. However, the modular blocks are relatively small so the assembly of big TES is time consuming, and the charge and discharge temperatures have a significant temperature variation of up to 100°C.

Latent solid-liquid storage solutions use a configuration similar to sensible storage in granular materials: modular containers with embedded pipes. The key difference is in the heat storage material that embeds particles of a reactive solid within a thermally stable matrix. As such, when the material is heated, the particles melt, but they are trapped within the matrix. These solutions have a typically lower TRL to sensible storage in granular materials and in molten salts, but they are also more compact and they provide heat at a more constant temperature.

The storage of sensible heat in solid materials can also be implemented in a single large storage vessel using, for example, a packed bed of aggregate. However, when solid storage materials are used, an intermediate heat transfer loop is required for both charging and discharging, typically employing air as the heat transfer medium to deliver heat to and extract heat from the storage material. A key challenge is the energy required to circulate the heat transfer medium, which reduces overall process efficiency due to pressure losses within both the storage unit and the heat exchange components. Consequently, this solution is generally better suited for large energy storage capacities with relatively low charging and discharging power levels, and therefore low heat transfer fluid flow rates. Another limitation is the relatively poor convective heat transfer performance of air as the heat transfer medium. This necessitates large heat exchange surfaces and, consequently, costly heat exchanger designs, particularly when higher power outputs are required.

Latent gas storage uses excess electricity to compress a gas, then it is cooled down and liquified at high pressure. When electricity is needed, the liquid is gasified with heat, then turbinised. The main drawback of the technology is that its main input is electricity, having a round trip efficiency of around 70%. The upside is that it does not affect the Rankine nor the Brayton cycles significantly.

Thermochemical storages use a reversible chemical reaction. When heated up, we start an endothermic reaction that produces a thermally-unstable compound. When this compound is cooled down, it decomposes in an exothermic reaction. They are well suited for seasonal storage, but their TRL is low.

Table 1 Table 5 shows the panorama of companies proposing TES, their technology, and the TES integration within our power block.

In general, it can be argued that the use of thermal energy storage (TES) is the most direct and natural form of energy storage for this application, since thermal energy is considered both at the input and the output of the storage system. Consequently, there is no conversion of energy from one form to another at any stage of the storage process, and the resulting efficiencies can therefore be relatively high, being limited primarily by thermal losses and the efficiencies of heat-exchange components.

With an appropriate operating regime for heat-to-heat storage, however, the efficiency of TES can easily exceed 90%. For this reason, attention is focused on TES technology, although many other energy-storage principles and, in particular, large-scale energy storage concepts also exist.

Table 5 Companies proposing TES

Company	TES technology	TR L	Max TES Discharge Temp [°C]	Max current scale (MWh)	Storage media	Means of charge	Means of discharge	Markets	Country	Integration powerblock	Data sources
EnergyDome	Gas Latent	7–8			CO2	Electricity	CO2 power cycle	Electricity, Grid stability	Italy	Independent	https://energydome.com/co2-battery/
HighView power	Gas Latent	7–8		5000	–	Electricity	Air Brayton cycle	Electricity, grid stability	UK	Independent	https://highviewpower.com/
Built to zero	Latent	4–5	600 °C	Unclear	PCMs cascade	Electricity	External steam generator				NOT FOUND
1414 Degrees	Latent	6–7	1200 °C	Any	MGA	Hot air	Hot air	Industrial heat	Australia	Upstream of Brayton Cycle	https://1414degrees.com.au/industry-uses/
MGA Thermal	Latent	6–7	1200 °C	1000	MGA	Electricity	Hot air	Industrial heat	Australia	Upstream of Brayton Cycle	https://www.mgathermal.com/energystorage
Thermophoton	Latent	4–5	1000 °C	Unclear	Eutectic iron-silicon boron alloy	Electricity	TPV, hot air	Electricity, Industrial heat	Spain	Discouraged in present form	https://www.thermophoton.com/technology-applications.php
M-TES	Latent	4	200 °C		Al-Sn based MGA	–	–	–	EIC pathfinder		
Kyoto Group	Sensible liquid	8–9	300	100	Ternary molten salts	Electricity	External steam generator	Industrial heat	Norway	Rankine cycle	https://www.kyotogroup.no/he atcube
Hyme Energy	Sensible liquid	7–8	700 °C	Any	NaOH	Electricity/heat	External steam generator	Industrial heat	Denmark	Between Rankine and Brayton	https://www.hyme.energy/
Malta Inc	Sensible liquid	7–8	580 °C	Any	Binary molten salts (solar salt)	Air heat pump	Air Brayton cycle	Electricity	USA	Between Rankine and Brayton	https://maltainc.com/malta-sems/
Built to zero	Sensible liquid	6	400 °C	Unclear	Ternary molten salts	Electricity	External steam generator	Industrial heat	Spain	Rankine Cycle - discouraged	https://buildtozero.es/thermalbox/
PUSH-CCC	Sensible liquid	4	730 °C		Carbonate and nitrate molten salts	A-CAES	A-CAES	Electricity	EIC pathfinder		UNCLEAR
Sunamp	Sensible liquid	8	118	~10	Water and concrete	Electricity	Hot water	Industrial heat	Spain	Discouraged in present form	https://sunamp.com/en-us/industrial/
Energynest	Sensible solid	8–9	400	1000	HEATCRETE®, cement	HTF in form of thermal oil or steam	HTF in form of thermal oil or steam	Industrial heat	Norway	Rankine Cycle	https://energy-nest.com/thermal-battery/
Brenmiller	Sensible solid	8–9	500	500	Crushed rocks	Heat recovery and electricity	Inner steam generation	Industrial heat	Israel	Between Rankine and Brayton	https://bren-energy.com/solutions/power-to-heat/
Kraftblock	Sensible solid	7–8	1300	~10MWh per container, stackable	Ceramic pellets and bricks	Hot air	Hot air	Industrial heat	Germany	Upstream of Brayton Cycle	https://www.kraftblock.com/technology
Rondo Energy	Sensible solid	7–8	1500	1000	Refractory bricks	Hot air	Hot air	Industrial heat	USA	Upstream of Brayton Cycle	https://www.rondo.com/products
Storworks power	Sensible solid	7–8	600	Any	Concrete	Hot air	Inner steam generation	Industrial heat	USA	Between Rankine and Brayton	https://www.storworks.com/

Company	TES technology	TR L	Max TES Discharge Temp [°C]	Max current scale (MWh)	Storage media	Means of charge	Means of discharge	Markets	Country	Integration powerblock	Data sources
Ecotech ceram	Sensible solid	6–7	1500	30	Waste ceramic	Hot air	Hot air	Industrial heat	France	Upstream of Brayton Cycle	https://www.ecotechceram.com/
Caldera	Sensible solid	6–7	204	100	Volcanic rocks	Electricity/heat	Inner steam generation	Industrial heat	UK	Discouraged in present form	https://www.caldera.co.uk/product
Lumenion	Sensible solid	7–8	600 °C		Steel Bars	Electricity/heat	Hot air	Industrial heat	Germany		NOT FOUND
Magaldi Power	Sensible solid	6–7	200	1000	Silica Sand	Electricity and hot air/steam	Inner steam generation	Industrial heat	Italy	Discouraged in present form	https://www.magaldigreenenergy.com/en/download
Polar Energy Night	Sensible solid	6–7	400	1000	Sand	Hot air	Steam	Industrial heat	Finland	Rankine Cycle	https://polarnightenergy.com/?gad_source=1&gad_campaignid=23602670866&gbraid=0AAAABC7HGUSUmcYt_QF2YRjCHPVf_eQmW&gclid=CjwKCAjw0dPRBhAPEiWAE5vTTpM_AOpwafNf3Uxr0wzKO93AnWuyRhWbTpFmKIM5qOQwXyKLlpVK8RoCJDIQAvD_BwE
Electrified Thermal Solutions	Sensible solid	5	1600	Any	Joule Hive™, bricks	Electricity/heat	Gaseous	Industrial heat	USA	Upstream of Brayton Cycle	https://electrifiedthermal.com/
Echogen	Sensible solid	5–6	600 °C	Any	Water and concrete	Heat pump	Transcritical CO ₂ power cycle	Electricity, grid stability	USA	Between Rankine and Brayton	https://www.echogen.com/technology/energy-storage
Antora Energy	Sensible solid	5–6	2000	-	Carbon	Electricity	TPV	Electricity, Industrial heat	USA	Discouraged in present form	https://www.antora.com/technology
Fourth Power	Sensible solid	5–6	2400	1000	Graphite	Electricity	TPV	Electricity	USA	Independent	https://gofourth.com/
Storasol	Sensible solid	9	1030	Any	Sand, gravel, rock, or stones	Hot air	Hot air	Industrial heat	Germany	Upstream of Brayton Cycle	https://storasol.com/en/die-technologie/
E2S Power	Sensible solid	8	550	5 MWh per container, stackable	Graphite	Electricity/hot air	Steam	Industrial heat	Switzerland	Between Rankine and Brayton	https://e2s-power.com/wp-content/uploads/2026/04/TW-EST_Built-for-energy-resilience_Utility-app.pdf
Kaaj Energy	Sensible solid	7	1000	Unclear	Granular materials (iron)	Hot air/electricity	Hot air	Industrial heat	Canada	Upstream of Brayton Cycle	https://kaajenergy.com/technology
Elstor Oy	Sensible solid	7	250	5 MWh per module, stackable	Granular materials	Electricity	Steam	Industrial heat	Finland	Rankine Cycle	https://elstor.fi/en/technology/
247 Solar Inc	Sensible solid	6	1000	10	Granular materials (ceramics, sand, iron slag)	Electricity	Steam	Electricity	USA	Rankine Cycle	https://247solar.com/sustainable-solar-solutions-products/heatstore/

Company	TES technology	TR L	Max TES Discharge Temp [°C]	Max current scale (MWh)	Storage media	Means of charge	Means of discharge	Markets	Country	Integration powerblock	Data sources
Exergy3	Sensible solid	5	1200	30	Granular materials	Hot air	Hot air	Industrial heat	UK	Rankine cycle	https://www.exergy3.com/solutions/
SaltX	Thermoc hemical	5–6	500 °C	Unclear	Calcium oxide	Electricity	None	Industrial heat	Sweden	Discouraged in present form	https://www.saltxtechnology.com/technology/
RedoxBlox /Tempo	Thermoc hemical	4–5	1500 °C	Unclear	Magnesium manganese oxide	Electricity	Hot air	Industrial heat	ARPA-e project	Upstream of Brayton Cycle	https://tempoenergy.com/product/ ; https://www.businesswire.com/news/home/20260331789263/es

Note that some of the companies presented above load their TES with electricity from the grid, but we would be able to heat them up directly with hot gas that ultimately comes from the reactor.

Some of the most recent TES applications that do not use molten salt are the following:

- Rondo TES at Holmes Western Oil Corp plant, USA, September 2025. 100 MWh at 1000°C for steam production. Uses sensible solid storage material. [Link](#).
- Brennmiller Energy at Enel plant, Italy, November 2022. 24 MWh at 550 °C for steam production. Uses sensible solid material. [Link](#).
- Kraftblock at Tata Steel plant, India, March 2026. 20 MWh at 400 °C for steel sintering. Uses sensible solid. [Link](#).
- Energynest at Yara plant, Norway, 2020. 4 MWh at 250 °C for steam production. Uses sensible solid. [Link](#).

The specification for the TREASURE project, defined in the paragraph 4.1, are recalled: a storage system with high maturity level, high thermal efficiency, able to store amount of energy around 1000MW·h thermal with a power in charge of 52MW_{th} and a power in discharge of 208MW_{th}, for temperatures in the range 76°C-545°C.

The storage also has to be charged with heat ultimately coming from the nuclear reactor. The solutions where the charge is done with the electricity produced by the turbines are not considered.

Considering the objective of the project of high maturity level, two main families of storages emerge: the two tanks using molten salts as storage media, and some sensible storage solutions using solid material as storage media, with readiness at 8-9: E2S Power, Storasol, KraftBlock, Rondo Energy, BrennMiller, Energynest

The main advantage of the concepts using solid material as storage media (crushed rocks, concrete, granular media, ceramic, sand...) is the natural adaptation to any temperatures as far as the maximum temperature of the storage is not exceeded. The storage system proposed by BrennMiller or Rondo Energy for example, with a maximum temperature of 1500°C, can easily adapt the temperatures of the project (76-545°C) and then maximize the storage density using the widest range of temperature.

The main disadvantages are:

- The size of the storage units, that varies from 1 to 10MW_h, requiring a large number of units to reach the 1000MW.h of the project, with a large number of piping and a large landscape. And there is no experience of a so large number of these units put together.
- The limited experience: these concepts are relatively new, at the stage of demonstration step, with no long-term feedback. Some technical issues could have been not seen at this stage.
- The low thermal efficiency. Due to the air coolant, the heat exchange between air and solid, and the conduction through the solid, there is a difference of temperature between charge and discharge that can be relevant. Data on that topic are difficult to collect in the open literature, but from our knowledge, this difference of temperature can vary from ~100°C to few hundreds of Celsius degrees.
- The pressure drop, with operational cost associated with fans or blowers that may represent a relevant share of the total cost [2].

The main advantages of the two-tanks storages using molten salts are the high thermal efficiency (no decrease of temperature between charge and discharge) and the very high maturity with hundreds of storages built and decades of use in the field of Concentrated Solar Plants. The maximum of storage has also frequently reached, for CSP application, the 1000MW.h mark expected for this project and high power > 100MW_{th}.

The main technical constraint is the limited range of temperature. Molten salts have to be kept liquid with a margin to avoid solidification in the piping, in particular during stand-alone phases, limiting the cold temperature that can be considered. On the other hand, the thermal degradation of the salt limits the maximum operational temperature. For example the Solar Salt, the molten salt used in CSP plants presented further in this document, has been used in the range of [290-560]°C to keep margin with solidification (240°C) and degradation.

Another drawback to be mentioned is the high operational cost due to the electrical heating systems required to maintain the salt in liquid phase during stand-alone and maintenance phases.

Considering the characteristics of the storage concepts available, we opted for a molten-salt TES with a two-tanks configuration. The main reasons for this choice are its high TRL and cumulated operational experience within the energy sector, and its high thermal efficiency. A detailed discussion on the two-tanks system, in particular on the molten salt choice, is presented in the next chapter.

4.3 Reference thermal storage solution: the two-tanks

The two-tanks system is based on a hot tank and a cold tank, as presented in the Figure 10, using a molten salt as liquid heat storage media. During the charge phase, the molten salt flows from the cold tank (initially full) to the hot tank (initially empty) through a heat exchanger to heat up the molten salt and extract energy from the Rankine cycle. During the discharge phase, the molten salt flows from the hot tank (initially full) to the cold tank (initially empty) through another heat exchanger to cool down the molten salt and restore the energy to the power block.



Figure 10 Illustration of the two-tank storage system for CSP application.

The main advantages of molten two-tanks storages are the following:

- **High maturity (TRL 8-9):** In 2018, International Energy Agency (IEA) identified 69 two-tanks storages using molten salt as heat storage media under operation worldwide [3], all of them connected to Concentrated Solar Plants. These storages all use Solar Salt as coolant.
- **High storage density,** in particular when the difference of temperature between the hot and cold tanks is high (typically $\sim 200 \text{ kW.h/m}^3$ for the Solar Salt in the range 290°C-565°C generally used in CPS plants).
- **Low cost:** The cost of a complete molten salt two-tanks system, including the charging and discharging heat exchangers and auxiliary systems, is about 100–200 \$/kWh_{th}. For the storage block of large CSP plants alone, IEA estimated in 2018 a cost in the range of 20 to 33 \$/kWh_{th} [3].

- Simplicity Two-tanks storage is easy to operate with a just a flow rate between two tanks to manage.

The main identified drawbacks of molten salt two-tanks storages are the following:

- Need to electrically heat the piping and heat exchangers during stand-by or maintenance phases to avoid salt solidification.
- Require a specific cooling system for the concrete basement under the storage for thermomechanical reasons.
- High operating cost due to the aforementioned electrical heating of piping and the cooling of the basement.
- Corrosiveness of molten salts, which implies the use of specific piping and tanks material.
- The hot tank thermo-mechanical stress, that has led to major maintenance operations in different CPS plants.

A particular attention has to be paid concerning the connection to a nuclear reactor, relative to safety: molten nitrate salts are not combustible, unlike thermal oils, but they are oxidizing agents and may therefore support combustion. The presence of a large quantity of oxidizing material has to be addressed in the safety study.

In the following subsections, we present molten-salt TES systems for different applications. We also discuss their compatibility with the requirements for the TES system of Treasure.

4.3.1 The two-tanks storage systems for CSP

The concept of two-tanks storage has been developed since the nineteen-eighties for CSP plant applications, to adapt the intraday mismatch between production and consumption.

Example of molten salts two-tanks storages with energy stored $> 1\text{GW}\cdot\text{h}_{\text{th}}$ are presented in Table 6. These examples illustrate the feasibility of very large storages using the two-tanks molten salt technology. A most detailed list of two-tanks storages connected to CSP is available in the publication [4].

This background from CSP application illustrate the high maturity of the two-tanks solution and the adequation with nuclear reactor application with regards to the need of storing a large amount of energy.

Table 6 Data of the principal molten-salt two-tanks heat storage installations with a capacity $> 1\text{GW}\cdot\text{h}_{\text{th}}$.

Installation	Temperatures	Material	Energy	Power	Salt Volume or mass
Andasol – 3 [5]	282/386°C	Solar Salt	1010 MWh_{th}	121 MW_{th}	28500t
Crescent Dunes [3]	288/565°C	Solar Salt	3300 MWh_{th}	330 MW_{th}	
Andasol - 1	293/393°C	Solar Salt	1050 MWh_{th}	131 MW_{th}	16300m ³ for each tank
Cerro Dominador (Atacama – Chili)	-	Solar Salt	6000 MWh_{th}	-	
Solana (Arizona, USA) [6] [4]	293-393°C	Solar Salt	4000 MWh_{th}	280 MW_{th}	135000t – 6*2 Tanks
GEMASOLAR (Spain) [4] [7]	290/565°C	Solar Salt	1000 MWh_{th}	-	2 tanks D=23m, h=10.5m 8500t

4.3.1.1 The example of the Crescent Dunes storage (Nevada, USA) [3]

The Crescent Dunes plant, located in Nevada (USA), is a 100MWe concentrated solar power plant under operation since 2015. The plant is composed of a 170m high solar tower, with utilities including a direct two-tanks storage system (**3300MWh_{th}**) using Solar Salt as heat storage media, surrounded by a 120ha solar panels field. The electricity produced in 2016 amounted to 125GWh_e.

The detailed data of the Crescent Dunes storages are presented in the Table 7. A picture of the plant including the two vessels is presented in Figure 11.

The Crescent Dune storage is an example of the possibility to store a large amount of energy (> 3GW.h_{th}) in a two-tanks system.

Table 7 Crescent Dunes storage main data.

	Crescent Dunes Storage (Nevada, USA)
Technology	Two Tanks
Material	Solar Salt
Temperatures	288 – 565 °C
Energy capacity	3300 MWh _{th}
Power	330 MW _{th}
Time to deliver heat	< 1min
Efficiency	99%
Capital Cost	20 €/kWh _{th}



Figure 11 Crescent Dunes (Nevada) CSP plant picture.

4.3.1.2 The Solar Salt

The totality of the two tanks storages built in industrial scale CSP plants use the same molten salt: the Solar Salt, especially developed for CSP application.

The Solar Salt is a binary mixture composed of 60%NaNO₃ and 40%KNO₃.

This salt has been widely used in CSP plants and widely studied in the literature.

The thermal properties of the Solar Salt, coming from open literature, are presented in Table 8. These data vary from one author to another. Considering the data coming from the existing storages, values of 240°C for the melting temperature, 565°C for the maximum operating temperature and 0.79 kWh/m³/K for the storage density are supposed for this study. The difference between the melting temperature (240°C) and the minimum operating temperature in the cold tank (range [282-293]°C in Table 6) shows the margin taken to avoid the solidification of the salt in the pipes (in addition to the electrical heating): more than 40°C of margin.

The thermal conductivity of the Solar Salt varies from 0.46 to 0.55 W/m/K in the range of [230-500]°C [8] and its viscosity at 300°C is 0.000326 Pa.s⁻¹ [4].

Table 8 Thermal properties of the Solar Salt.

Solar Salt	T _{melt} (°C)	T _{max operation} (°C)	C _p (300°C) (J/Kg/K)	ρ (300°C) (kg/m ³)	ρ.C _p (300°C) (kWh/m ³ /K)
Gonzalez Roubaud Error! Reference source not found. (2017)	220	585	1495	1899	0.79
Caraballo Error! Reference source not found. (2021)	240	565	1494,6	1899,2	0.79
Bauer Error! Reference source not found. (2013)	240	530-565	1550	1840	0.79
Pfleger Error! Reference source not found. (2015)	240	550	1500-1575	1880	0.78-0.82
Abengoa [9] (2013)	220	585	1495	1899	0.79

The Solar Salt has been selected for CSP applications for its high maximum operation temperature, relatively low cost (about 2 \$/kg according to current supplier offers for molten-salt grade material, compared with 0.5 - 1.3 \$/kg reported in **Error! Reference source not found.****Error! Reference source not found.** **Error! Reference source not found.****Error! Reference source not found.**) and relatively high storage density. However, it suffers from a high melting temperature requiring electrical heating for piping and vessels, and from corrosiveness at high temperature. As the most used and studied molten salt, with the highest background knowledge and maturity, **the Solar Salt is considered as the reference candidate for the TREASURE storage.**

4.3.1.3 Other salts studied for CSP plants

The high melting point of the Solar Salt, and its consequences in operating costs, has led to search for alternative molten salts with lower melting points. The Table 9 illustrates these studies, presenting part of the molten salt studies in the last decades. Most of these salts are at a very low readiness level, with just laboratory characterization of some thermal properties, and are not considered in this study.

Table 9 Thermal properties of some alternative molten salts [10].

Molten Salt Mixtures (comp wt%)	Name	T_{melt} [°C]
KNO ₃ -NH ₄ NO ₃ -AgNO ₃ (20-47-33)		52
KNO ₃ -KNO ₂ -LiCl-LiNO ₃ -Ca(NO ₃) ₂ -NaNO ₂	Saltstream 300	56
LiNO ₃ -NaNO ₃ -KNO ₃ -CsNO ₃ -Ca(NO ₃) ₂	Saltstream 500	65
LiNO ₃ -Ca(NO ₃) ₂ -NaNO ₂ -KNO ₂ (24.6-13.6-16.8-45)	CaLiNaK	72
KNO ₃ -LiNO ₃ -Ca(NO ₃) ₂ (50-80)-(0-25)-(10-45)		80
KCl + AlCl ₃ + NaCl (11-78-11)		88.9
KNO ₃ -NaNO ₃ -LiNO ₃ -Ca(NO ₃) ₂ (54.54-9.09-18.18-18.18)		90
KNO ₃ -LiNO ₃ -NH ₄ NO ₃ (24-25-51)		92
LiNO ₃ -NaNO ₃ -KNO ₃ -CsNO ₃ -Ca(NO ₃) ₂ (8-6-23-44-19)		95
NaNO ₃ -KNO ₃ -LiNO ₃ -Ca(NO ₃) ₂ (9-18)-(40-52)-(13-21)-(20-27)	Sandia Mix	95
NaNO ₃ -KNO ₃ -LiNO ₃ -NaNO ₂ (14.2-50.5-17.5-17.8)	Quaternary	99
LiNO ₃ -NaNO ₃ -KNO ₃ -Sr(NO ₃) ₂ (29-17-49.4-4.6)		105
NaCl-AlCl ₃ (20-80)		108
KNO ₃ -CaNO ₃ -LiNO ₃ (21-18-61)		117
NaNO ₃ -KNO ₃ -Ca(NO ₃) ₂	Saltstream XI	120
NaNO ₃ -KNO ₃ -LiNO ₃ (18-52-30)	LiNaK	120
NaNO ₃ -KNO ₃ -Ca(NO ₃) ₂ (7-45-48)	HITEC XL	120
KCl-AlCl ₃ (22-78)		128
NaNO ₃ -KNO ₃ -LiNO ₃ (28-52-20)	LiNaK	130
KNO ₃ -LiNO ₃ (68-32)	LiK	133
NaNO ₃ -KNO ₃ -Ca(NO ₃) ₂ (15-42-43)		133
NaNO ₃ -NaNO ₂ -KNO ₃ (7-40-53)	HITEC	142
NaOH-KOH (42-58)		170
NaNO ₃ -KNO ₃ (60-40)	Solar Salt	222

Nevertheless, one of these salts proved to be of particular interest and was therefore investigated further: the ternary mixture 7%NaNO₃-53%KNO₃-40%NaNO₂, also named HITEC. The main interest of the HITEC salt is the lower melting point of 142°C, as presented in the Table 10, with a storage density similar to Solar Salt. The maximum operating temperature is however lower than Solar Salt, with a value of 450°C.

Table 10 Thermal properties of the HITEC salt.

HITEC	T_{fusion} (°C)	T_{max} (°C)	C_p (300°C) (J/Kg/K)	ρ (300°C) (kg/m ³)	$\rho \cdot C_p$ (300°C) (kWh/m ³ /K)
Gonzalez Roubaud Error! Reference source not found. (2017)	142	450-538	1560	1860	0.81
Fernandez Error! Reference source not found. (2019)	142	535-600	1560	1700	0.74
Caraballo Error! Reference source not found. (2021)	142	450	1559,7	1718,4	0.74

Bauer Error! Reference source not found. (2013)	142	450	1540	1790	0.77
Boerema Error! Reference source not found. (2012)	142	535	1560	1860	0.81
Abengoa Error! Reference source not found. (2013)	142	450-538	1560	1860	0.81

The HITEC salt has a maturity level higher than most of the other molten salts studied in the literature, with the achievement of two demonstrators: Themis in France (310m³ – 40MWh_{th}) and CESA-1 in Spain (200m³ – 12MWh_{th}) [11].

The HITEC salt is therefore considered a candidate for the TREASURE storage.

4.3.2 Small modular reactors featuring heat storage systems

Some Small Modular Reactor projects propose heat storage installations to increase flexibility. Eight designs have been identified and are summarized in the Table 11; however, very little data are available concerning the storage. When data relative to the storage are available, the concept is **almost always** two-tanks with **Solar Salt**. The reason given is that that material has the most cumulated working hours in molten-salt TES systems of existing, commercial facilities.

Table 11 Projects of SMR including thermal storage.

Name	Capacity	Type	Developer	TES
SMR 300	300 MWe	PWR	Holtec, USA + SNC-Lavalin, Canada	Green boiler –Feorite
Natrium	345 MWe	Sodium FNR	TerraPower + GE Hitachi, USA	2 tanks –Solar Salt (to be confirmed)
Integral MSR	192 MWe	MSR	Terrestrial Energy, Canada	
Moltex SSR-W	300 MWe	MSR	Moltex, UK	Gridreserve–Solar Salt
Westinghouse SMR	225 MWe	Integral PWR	Westinghouse, USA*	
Westinghouse LFR	300 MWe	Lead FNR	Westinghouse, USA	
Moltex SSR-U	150 MWe	MSR/FNR	Moltex, UK	Gridreserve-Solar Salt
MMR-5/-10	5 or 10 MWe	HTR	UltraSafeNuclear, USA	

4.3.3 Commercial concepts using molten salt two-tanks systems

In recent years, a new field of solutions has emerged for large scale energy storage systems such as Carnot Batteries or Compressed Air Energy Storages (CAES).

Different commercial concepts have been developed to meet market demand for thermal energy storage [2], including molten salt two-tanks systems.

These new concepts follow two main fields of innovation:

- Develop alternative molten salts to the Solar Salt currently used in CSP plants in order to reduce corrosiveness and cost, lower the melting temperature of the salt to minimize electrical heating requirements, and increase the maximum operation temperature to enhance energy storage density.
- Reduce tank size and increase modularity to reduce thermomechanical constraints.

As examples, the following commercial concepts are currently being developed:

- “Built to zero” is a Spanish start-up developing the Thermalbox [12], a solution for industry decarbonation via a power-to-heat solution. The system includes a molten salt two-tanks storage with cold and hot temperatures of respectively 180°C and 400°C. The molten salt is a ternary mixture. Considering these temperatures, and the very few data available in the literature concerning the ternary salt used, the Thermalbox is not retained for the TREASURE project. Due to its slightly higher operating temperature range, the HITEC salt is preferred.
- Hymne Energy is a spinoff of the nuclear engineering company Seaborg Technologies, created in 2021. Hymne Energy has developed a Carnot Battery including a two tanks storage system filled with sodium hydroxide (NaOH) [2], covering a wide range of temperatures, from 200-350°C for the cold storage to 600-700°C for the hot storage. Hymen Energy has constructed a TRL6 demonstrator in Ejberg in 2024, which is however still lacking full functionality **Error! Reference source not found..** Considering this relatively low level of maturity, this technology is not considered for the TREASURE project.
- Mala Inc, a US company, proposes a Carnot Battery including a long-term thermal energy storage. The TES is a two-tanks concept using a binary molten salt with a temperature range of 580°C-280°C that is not clearly identified, but could be the Solar Salt.

4.3.3.1 *Kyoto Group and the Yara Most Salt*

Kyoto Group has patented a new molten salt, the Yara Most, a ternary mixture of potassium nitrate (KNO_3 – 43 wt %), sodium nitrate (NaNO_3 – 15 wt %) and calcium nitrate ($\text{Ca}(\text{NO}_3)_2$ – 42 wt %), for power to heat application. The main advantage is **the reduction of the melting point to 131°C**.

The salt is stored in dedicated tanks, each with a storage capacity exceeding 8MWh_{th} , which can be connected to reach capacities between 16 and $120\text{MWh}_{\text{th}}$. The system is charged via a molten salt heater. For discharge, the hot molten salt flows through a steam generator to produce steam in the temperature range of 170-400°C [2].

In 2023, a first demonstrator was inaugurated, featuring a storage capacity of 18MWh_{th} , a rating of 5MW in charging and 4MW in discharging, and containing 150 tons of Yara Most Salt **Error! Reference source not found..**

Kyoto Group has then moved forward commercial projects at KALL Ingredients Kft, a Hungarian food processing factory (commissioning at the end of 2024) and for Klingele, a German paper and packaging manufacturing company [12].

The Yara salt is also used in the CSP demonstrator Évora Molten Salt Platform (EMSP) in Portugal since 2021. The solar field, the heat storage and the heat exchangers are filled with 92 tons of Yara Most salt. A temperature of **500°C has been reached, with a cumulative operating time of around 5500h**.

The concept proposed by Kyoto Group is therefore considered to have a high level of maturity (TRL 7-8). The detailed characteristics of the YARA Most salt are the following:

Density measured in the range 2100-1850 kg/m^3 between 120°C and 520°C, as presented in the Figure 12 [13].

Heat capacity in the range 1580-1520 J/kg/K between 130°C and 400°C, as presented in the Figure 12 [13].

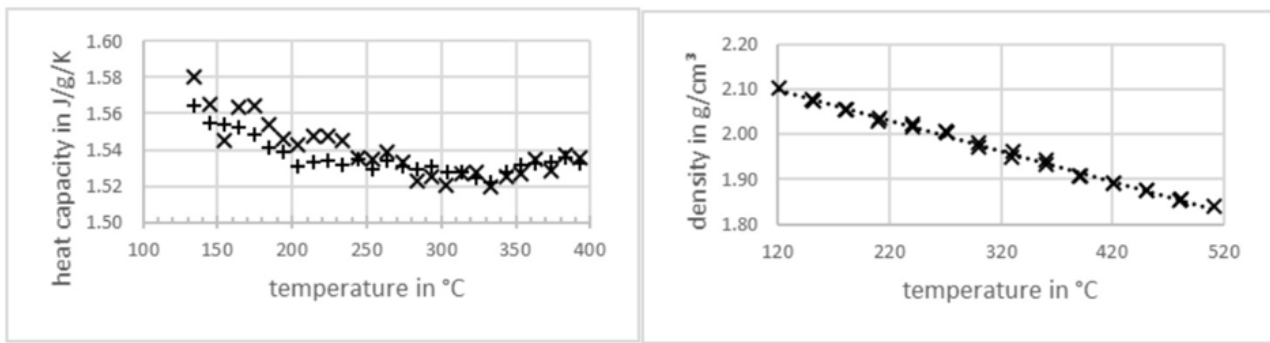


Figure 12 Heat capacity and density of the Yara Most salt [13].

Viscosity in the range 9-2 cP between 200°C and 400°C [14]. An interesting characteristic of Yara Most Salt is the undercooling of the mixture : while it melts at 131 °C, it freezes at lower temperatures because of hysteresis (a welcome phenomenon that limits the risk of freezing). This allows the measurement of viscosity below the freezing point, as presented in the Figure 13. In laboratory, the viscosity has been measured down to 80°C. The Yara Most salt can then be pumped below the freezing point, offering a complementary safety margin against solidification.

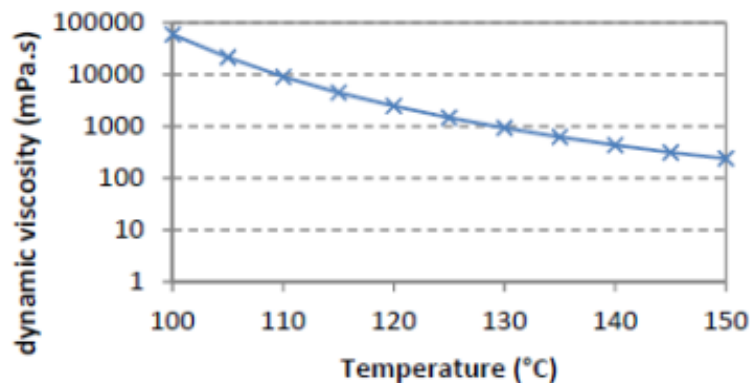


Figure 13 Viscosity of the Yara Most salt close to the melting point [15].

Operating temperatures:

The **minimum operating temperature** considered for the Yara Most salt is generally accepted as **170°C**, providing a margin of 40°C with respect to the melting temperature.

The **maximum operating temperature** varies among authors. Trevisan et al [15] consider a safe working temperature of 450°C, with an estimated degradation temperature of 500°C and a margin of 50°C. C.A. Pan et al. [17]**Error! Reference source not found.** consider the same value of 450°C. P. Lukasova et al. [18]**Error! Reference source not found.** consider a smaller margin and retain a maximum hot temperature of 480°C. Antonio Marco Pantaleo et al. [2] report a maximum temperature of 420°C for the Kyoto Group storage., The temperature of 500°C which has been sustained for a cumulative operating time of around 5500h in the CSP demonstrator EMSP in Portugal corresponds to the maximum temperature recommended by the manufacturer Yara. The difference between these values depends on the approach considered. The Thermogravimetric analysis (TGA) of the salt reveals a mass loss beginning slightly above 450°C (Figure 14). Furthermore, analysis of the composition of a sample collected from the EMSP demonstrator after operation at 500°C shows a change in the salt composition (Figure 15**Error! Reference source not found.**). However, the thermal performance of the salt is not affected by this compositional change.

The question of maximum operation temperature should be investigated further. For the time being, the value reported for the EMSP demonstrator and recommended by Yara Most Salt manufacturer is retained: **500°C**.

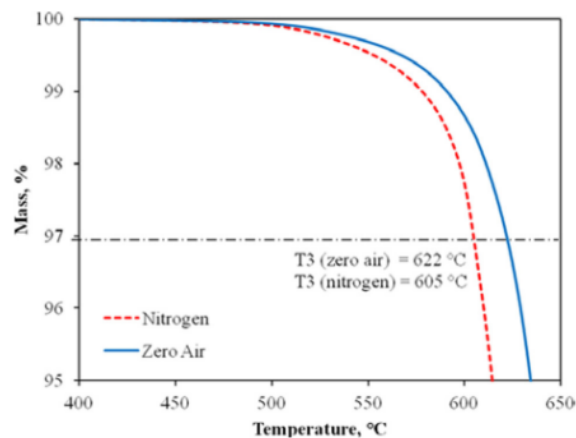


Figure 14 TGA results for the relative thermal stability of Yara Most.

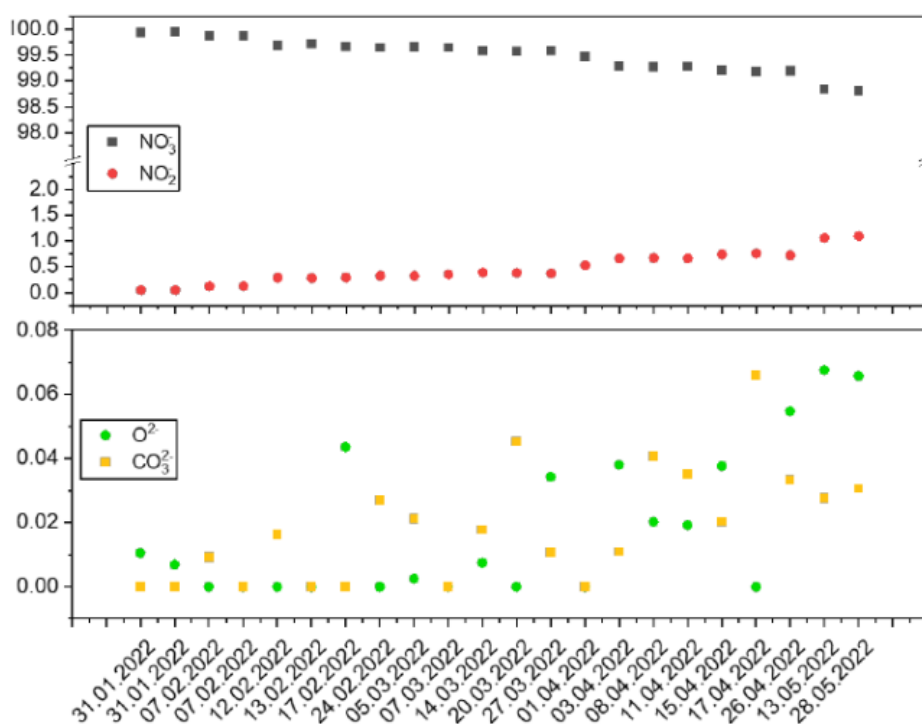


Figure 15 Top : Nitrate and nitrite levels in [mol%] in extract sale samples during operation.
Bottom: Carbonate and oxide-ion concentrations in [mol%] from the same samples

Considering its high maturity level, the first demonstrators successfully built, and its interesting thermal properties with respect to the requirements of the project (in particular in terms of the operation temperature range), **the Yara Most salt is considered** as a potential candidate media **for the TREASURE storage**

Remark: Other mixtures of KNO_3 – NaNO_3 – $\text{Ca}(\text{NO}_3)_2$ have also been proposed in the literature, with the denomination of HITEC XL (one of them is presented in the Table 9 **Error! Reference source not found.**), but no prototype or demonstrator has been built with this composition, except for the Yara Most salt. Therefore, within this TREASURE study, only the HITEC XL formulation marketed as Yara Most Salt will be considered. Other HITEC XL formulations are considered outside the scope of this study.

4.3.4 Selection of the salt

Three molten salts have been selected in the previous paragraphs considering the requirements of the TREASURE project: Solar Salt, HITEC and Yara Most. The characteristics of these salts are presented in the Table 12. The three salts presents a similar storage density per Celsius degree ($\rho \cdot Cp$).

The Solar Salt has the highest maturity (TRL 9), at a moderate cost, but with a high minimum operating temperature of 283°C. This is very far from the 76°C available in the tertiary circuit of the Allegro reactor, that will lead to a decrease of the storage density $\rho \cdot Cp \cdot \Delta T$ and then will require a higher mass of salt, leading to a higher cost for the storage. In a two-salt arrangement, however, this drawback is removed: Solar Salt is used only in the high-temperature section, where its high maximum operating temperature allows 545 °C steam to be raised, while a lower-melting salt covers the low-temperature range.

The HITEC salt presents the largest operating temperature range (185-530°C), but a higher cost and a lower maturity (TRL 6-7, only two demonstrators were ever built).

The Yara Most salt represents a good compromise of a large temperature range (170°C-500°C), a low price and a high maturity with 4 demonstrators currently in operation. For these reasons, Yara Most is selected for the single-salt alternative design. Because it is limited to 500 °C, however, a single-salt system cannot deliver the 545 °C live steam required by the tertiary cycle. The reference solution therefore combines Solar Salt in the high-temperature section with HITEC in the low-temperature section, as described in Section 4.3.6.

Table 12 Characteristics of Solar Salt, HITEC and YARA MOST.

	Solar Salt	HITEC	YARA MOST
Composition	60 wt.-% NaNO ₃ 40 wt.-% KNO ₃	40 wt.-% NaNO ₂ 53 wt.-% KNO ₃ 7 wt.-% NaNO ₃	43 wt.-% Ca(NO ₃) ₂ 42 wt.-% KNO ₃ 15 wt.-% NaNO ₃
Melting temperature	240°C	142°C	131°C
Minimum operating temperature	283°C	~185°C Estimated considering the same margin with melting temperature than the solar salt	170°C
Maximum operating temperature	>560°C	530°C	500°C
Density (kg/m ³) (300°C)	1899	1860	1950
Heat Capacity (J/kg/K) (300°C)	1495	1560	1525
$\rho \cdot C_p$ (300°C) (kWh/m ³ /K)	0.79	0.81	0.82
Price \$/kg [14]	[0.5-1.3]	[0.9-1.9]	[0.3-1.8]
TRL	9	6-7	7-8

4.3.5 Implementation of the storage system

This section illustrates the integration of the storage into the power conversion cycle for the single-salt Yara Most alternative; the same operating principles apply to the reference two-salt design described in Section 4.3.6. Since Yara Most solidifies at around 140°C and decomposes above 525°C (with recommended operational temperatures in the literature being in the range of 170-500°C), it is advisable to ensure that the fluid interfaces with the Rankine and Brayton cycles remain in this range. Indeed, the choice of the salt affects the operational parameters of the whole power conversion cycle.

While intensive parameters such as pressure and temperature will remain the same in both energy storing and discharge phases, the main difference is that the flowrates downstream of the molten-salt steam generator will vary. In energy storing mode, the cold molten-salt pump flowrate is higher than the hot molten-salt pump flowrate, while in discharge it is the opposite. This means that the Brayton cycle will always work on steady state and the Rankine cycle will accommodate all the variability in the electricity production.

The storage energy level and the total power production (the sum of the steam and gas turbine outputs) for a reactor of 200 MWth are represented in Figure 16 **Error! Reference source not found..**

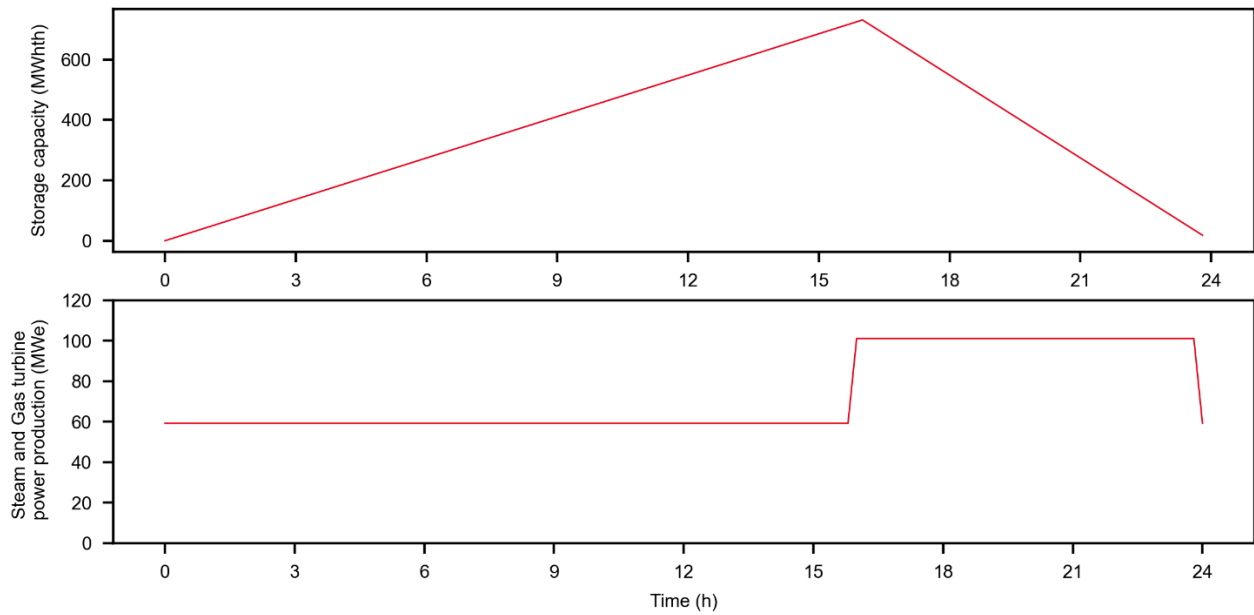


Figure 16 Energy stored in TES and power production

There are two possible configurations of such a storage in the power-conversion block: in series (see Figure 17) and in parallel (see Figure 18). The configuration in series requires less equipment and uses less electrical heat tracing for the salt system, but a problem in the molten-salt system would force the reactor to stop. The parallel configuration requires more equipment and more extensive heat-tracing operation, increasing both CAPEX and OPEX. However, it offers improved reliability, as a shutdown of the molten-salt system would still allow the power conversion block to operate, albeit with limited flexibility.

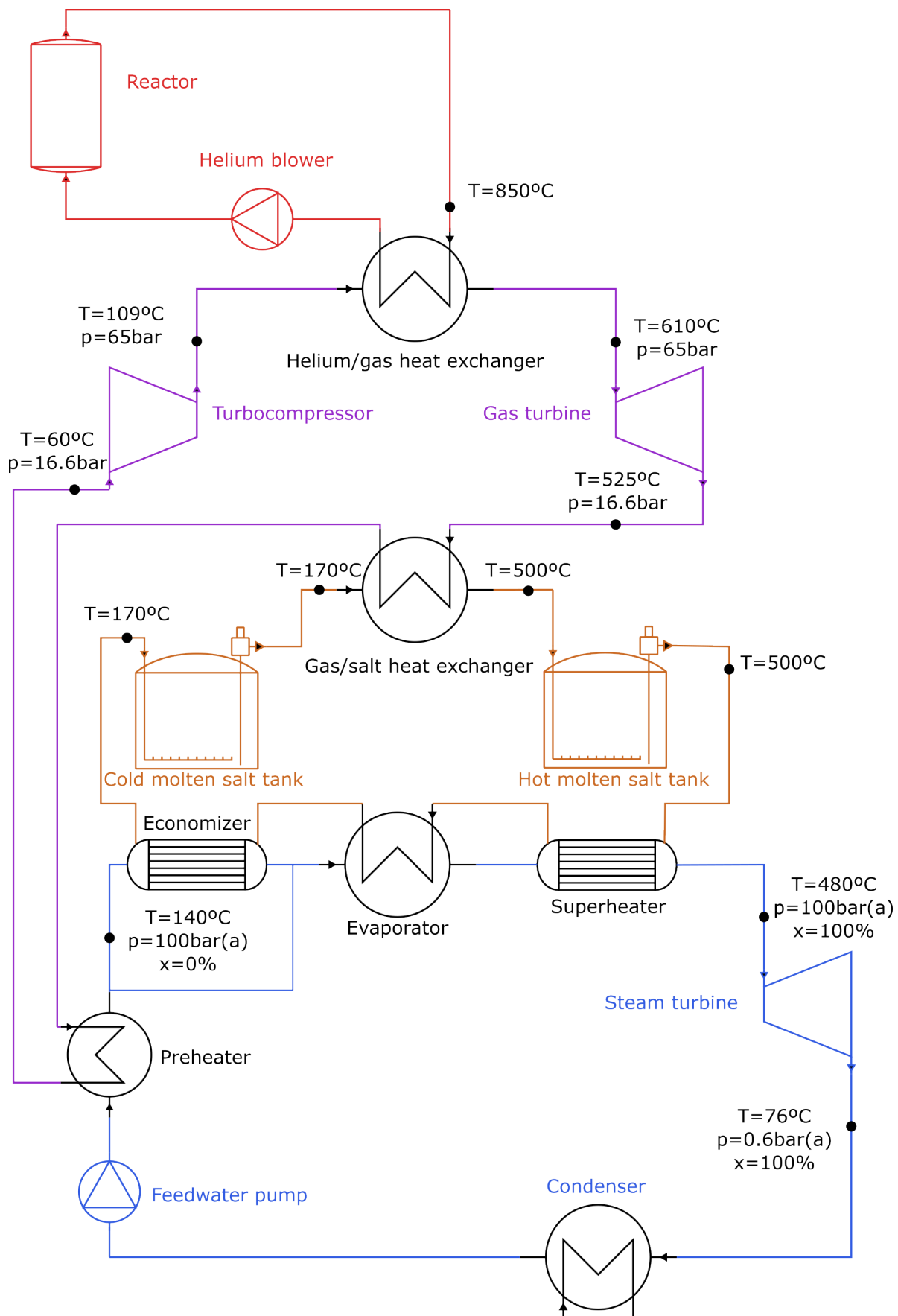


Figure 17 Operational parameters of the power conversion cycle when implementing TES with Yara salt in series

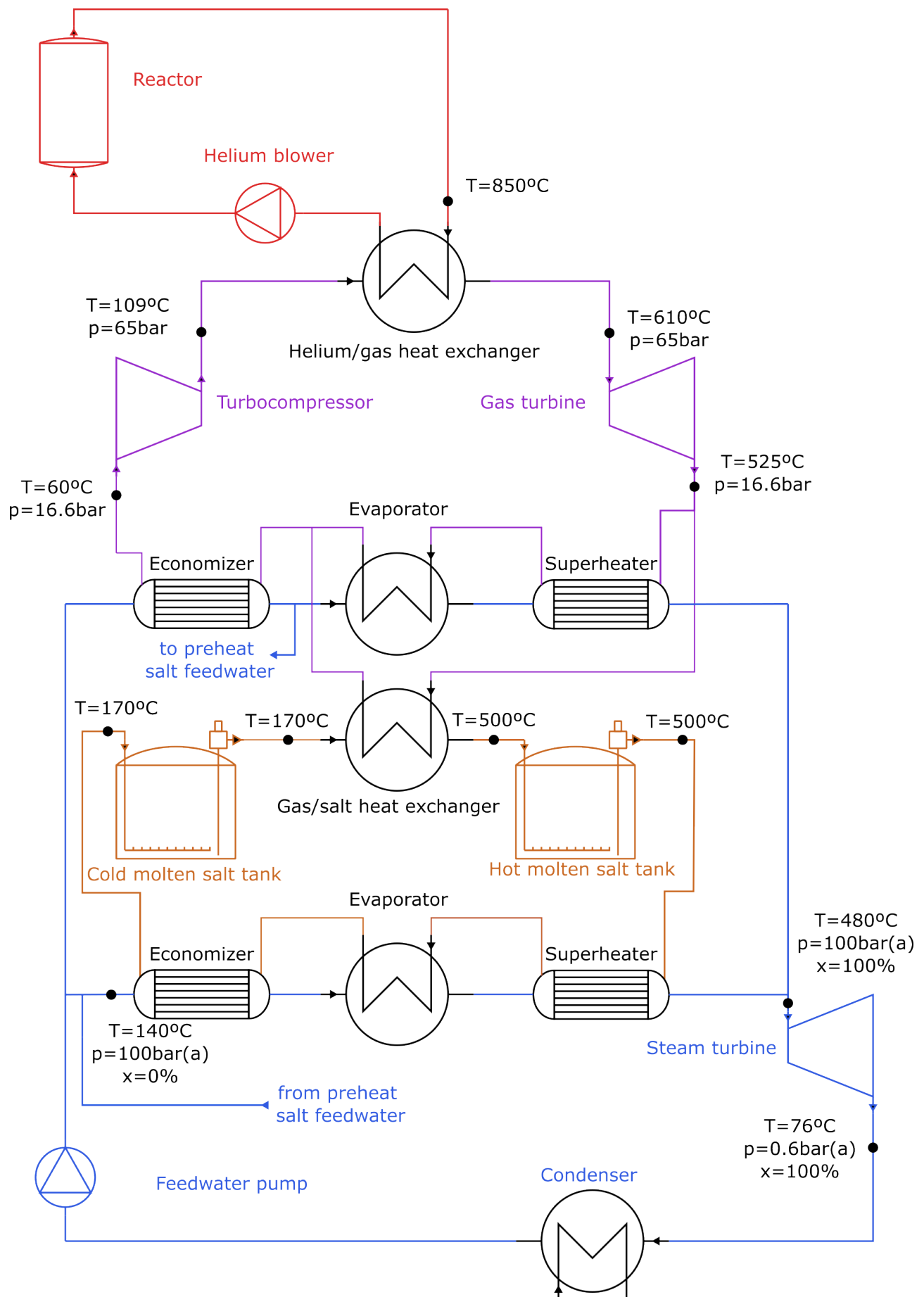


Figure 18 Operational parameters of the power conversion cycle when implementing TES with Yara salt in parallel

4.3.6 Alternative design employing two salts

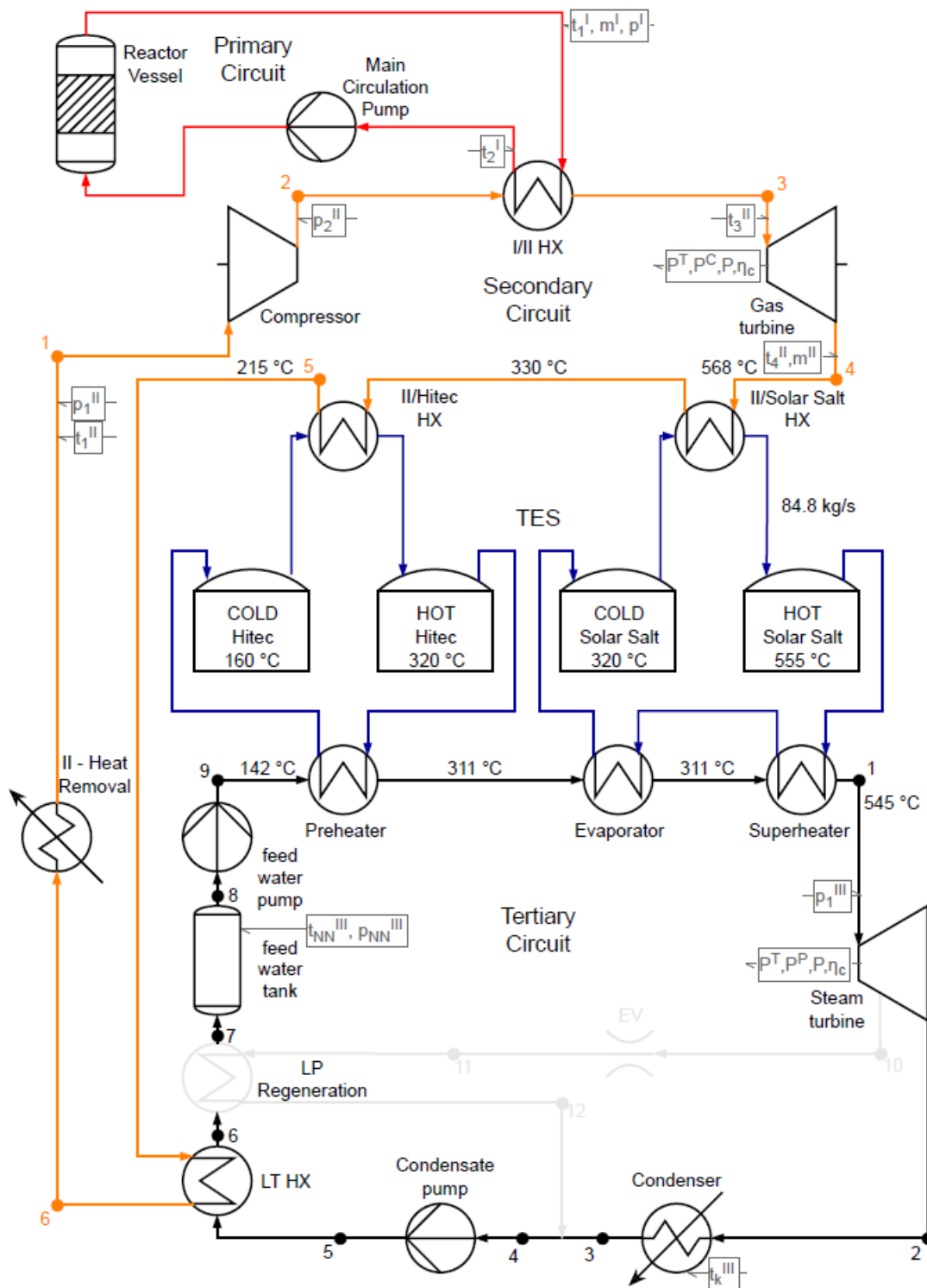
Another option under consideration is the integration of two thermal energy storage systems connected in series, each employing a different storage salt. The main advantage of this approach is the possibility of increasing operating temperatures, thereby achieving higher storage capacity and improving the overall efficiency of the power conversion cycle.

The concept is based on dividing the storage section into a high-temperature system, utilizing so-called Solar Salt, and a low-temperature system, utilizing HITEC salt. This arrangement makes it possible to achieve a steam outlet temperature in the tertiary circuit of up to 545°C, as originally envisaged in the reference design of the power conversion cycle.

The main drawback is the need to implement two separate storage systems, requiring at least four storage tanks in total, compared with two for the single-salt alternative.

The thermal energy storage system is charged by the secondary circuit, whose working fluid is nitrogen. The secondary circuit must operate at a constant mass flow rate, and therefore at a constant power level, in order to continuously remove heat from the primary circuit. Charging is achieved through heat exchangers that transfer heat from the nitrogen to the molten salt. The nitrogen temperature must be reduced through feedwater regeneration in the tertiary circuit and by means of external cooling to ensure adequate compressor efficiency in the secondary circuit.

Discharging is accomplished by generating superheated steam from the thermal energy stored in the molten salt and supplying it to the tertiary circuit, with the power output controlled through regulation of the steam flow to the tertiary circuit turbine. The discharge system is implemented in three stages, with feedwater preheating up to the saturation point taking place in the low-temperature section of the thermal storage unit. The evaporation stage and part of the superheating process are carried out in the high-temperature section, where heat is supplied by the solar salt.



4.3.7 Reference design proposed

In this paragraph, orders of magnitude of the size and the cost of the storage are presented, both for the single-salt alternative based on Yara Most and for the reference two-salt design. Considering the current progress of the project, only a rough estimation is presented. In the next steps, detailed design should be investigated in close relationship with a manufacturer.

Quantity of salt:

For the single-salt alternative, considering the temperatures of 170°C and 500°C for the cold and hot tanks, the storage density of 0.82 kW.h/m³/K and the energy to be stored of around 730MW·h, a total of 2700m³ of Yara Most are necessary, i.e. **~5200 tons**.

Volume of the hot and cold tanks:

The largest tanks built for CSP application have significantly exceeded the 3700m³ volume considered in this project, reaching capacities of more than 16000m³ (38.5m diameter – 14m high) according to [7]**Error! Reference source not found..** It seems then reasonable to consider **two tanks of 2000m³ each**.

Cost:

The estimation of the cost of the storage system is based on literature.

Prieto et al. [19] studied the cost of two-tank storage systems for 147MWe CSP plants (312-540°C – Solar Salt) and concluded that the cost depends on the storage size. They reported values in the range of 60-102€/kWh_{th} for storage capacities ranging from 3 to 10 hours. An AIE document [3] dedicated to CSP concluded in costs in the range 20-33\$/kWh_{th}, for storage systems using Solar Salt at 565°C. A document from NREL [20] reported a cost of 26.22 \$/kWh_{th} for a molten salt system at 1.23 \$/kg, used in the range of 293-565°C. The cost of the storage of the Crescent Dune CSP plant was reported as 20 \$/kWh_{th}. The cost cited in literature varies in a large range, from 20 to 100 \$/kW.h_{th}. This cost depends on the size of the storage, the range of temperatures, the molten salt used and the power in charge and discharge (through the size of the heat exchangers).

The cost estimation for the single-salt alternative is based on two techno-economic studies focused on Carnot Batteries, including a two-tanks storage using Yara Most Salt as storage media, i.e. the studies of Trevisan & al. **Error! Reference source not found.** and Lukasova & al. **Error! Reference source not found..** The data from these studies and the related cost elements calculated for the TREASURE storage are presented in the Table 13 and Table 14. The cost estimate based on Trevisan et al. leads to a storage cost of 67 M€ (67k€/kW.h_{th}), whereas the estimate based on Lokasova et al. concludes in a storage cost of 53 M€ (53k€/kW.h_{th}). These costs are hence within the range 20 to 100 \$/kW.h_{th} found in the literature. The contribution of the steam generator to the total cost has to be underlined (~30%), illustrating the significant impact of the power rating (208MW_{th}) on the overall cost of a two-tanks system.

Finally, considering the studies of Trevisan et al. [16]**Error! Reference source not found.** and Lukasova et al. [18] with margin, the cost of the single-salt alternative storage system can be estimated in the range **50-70 M€**.

Table 13 Estimation of the cost of the TREASURE storage based on the study of Trevisan & al. [17]

	Trévisan & al.	Treasure storage data		Treasure storage cost (k€)
Molten Salt Tanks (€/kWh _{th})	30	730 000	kWh _{th}	21 900
Circulation system (€/kW _{th})	25	120 000	kW _{th}	3 000
Steam Generator (€/kW _{th})	120	120 000	kW _{th}	14 400
Salts (€/kg)	1	5 200 000	kg	5 200
On site preparation (€)	150000			150
Total				44 650

Table 14 Estimation of the cost of the TREASURE storage based on the study of Lukasova & al. [19]

	Lukasova & al.	Treasure storage data		Treasure storage cost (k€)
Molten Salt Tanks (€/kWh _{th})	14,8	730 000	kWh _{th}	10 804
Balance of the system (€/kW _{th})	25	120 000	kW _{th}	3 000
Steam Generator (€/kW _{th})	120	120 000	kW _{th}	14 400
Salts (€/kg)	1,1	5 200 000	kg	5 200
On site preparation (€)	150000			150
Total				33 554

However, it should be noted that the data describing the CAPEX of actual implemented projects are very limited and, given the unique nature of this application within an advanced nuclear power plant, a high degree of uncertainty must be expected. Furthermore, although supply chains exist for all key components and materials, they remain relatively constrained, and the current cost of both equipment and thermal storage materials may be significantly influenced by market conditions and the volume of similar deployments worldwide.

A further increase in costs can also be reasonably anticipated due to the specific requirements associated with deployment on the nuclear island, particularly the stringent emphasis on nuclear safety. This is expected to necessitate an extensive range of analytical, experimental, and administrative activities related to technology qualification, licensing, and safety demonstration, the scope and costs of which cannot currently be predicted with sufficient confidence.

Using a different methodology, a CAPEX estimate was developed for the reference two-salt concept described in Section 4.3.6. This design is based on smaller storage tanks with a total storage capacity of 168 MWh, of which 135 MWh is stored in the high-temperature section using solar salt and 33 MWh in the low-temperature section using HITEC salt. The maximum charging and discharging power is approximately 50 MW; this value, which has a significant impact on the size and cost of the charging heat exchangers and steam generation system, was used as the basis for the CAPEX estimate.

The CAPEX values are derived from actual supplier quotations obtained through CVR's thermal energy storage activities, as well as from expert estimates and consultations with manufacturers of selected components. The estimate assumes a realistic configuration of the heat exchangers, including two charging nitrogen-to-molten-salt heat exchangers (2 × charging nitrogen/molten salt HX) and a superheated steam generator consisting of a feedwater preheater, heating the feedwater to the saturation point using the low-temperature storage system, together with an evaporator and superheater supplied with heat from the high-temperature solar salt circuit. A different storage tank concept has also been considered. The low-temperature storage system may be implemented using horizontal vessels, whereas the significantly larger high-temperature storage tank is assumed to employ a vertical configuration. In addition, the estimate includes the other major components required for the TES system.

Solar salt (1378 t, 1.5 EUR per kg)	2 067 000
Solar Salt tanks (2x D=12.5 m, H = 6.25 m)	1 600 000
HITEC salt (512 t, 1.8 EUR per kg)	921 600
HITEC salt tanks (2x D=9 m, H=4.5 m)	500 000
Molten Salt Pumps	375 000
Charging system (nitrogen/molten salt HX)	6 000 000
Discharging system (molten salt steam generator)	4 000 000

Valves, piping, insulation, heat tracing	3 000 000
Construction and civil works	1 000 000
I&C	1 000 000
Engineering (10% of cost)	2 046 360
Total	22 509 960

It is evident that the specific investment costs are significantly higher than those estimated for the single-salt alternative. This primarily reflects the substantial uncertainty associated with CAPEX estimation. Nevertheless, in both cases the investment costs remain relatively high and are expected to constitute a significant portion of the overall project implementation costs. For this reason, it is essential to carefully define the operational strategies and revenue streams in order to ensure the economic viability of the system.

As for the single-salt alternative, the estimated CAPEX does not include the costs associated with technology development for nuclear applications, nor the related safety assessments, licensing activities, and technology qualification processes required for deployment in a nuclear environment.

4.3.8 Techno-economic considerations

Although the concept of enhancing GFR reactor flexibility through the integration of thermal energy storage (TES) is indisputable, and its consideration is essential given the high-temperature nature of the reactor concept and its intended applications, careful attention must be paid to the technical and economic challenges, as well as to the need for further development, before such a system can be implemented.

4.3.8.1 Choice of the storage principle and concept

The selection of the thermal energy storage principle is based on the direct use of thermal energy as both the input and output energy form. Therefore, choosing TES over other physical principles of large-scale energy storage is a natural and logical option. The selection of a concept employing a liquid storage medium, specifically molten salts, is primarily driven by the high technology readiness level (TRL) and the availability of the technology.

A number of alternative concepts exist; however, they have been excluded from consideration for this application, or at least under the current state of technological development. Sensible heat storage in solid materials is not well suited to the high charging and discharging thermal power requirements of the system, particularly due to the associated need for an additional heat transfer medium. Latent heat storage based on phase-change materials does not currently offer a sufficiently reliable solution, as the temperatures involved would generally require the use of metallic alloys. These materials tend to be highly aggressive toward structural materials, leading to accelerated degradation and reduced system lifetime. This is a critical concern, as long service life is essential for both the economic viability and the operational safety of the system.

4.3.8.2 Nitrite salt issues

Nitrate salt as a thermal energy storage medium offers several advantages, including its relatively low cost, compatibility with stainless steels, non-toxic and non-flammable nature, and recyclability. A key operational challenge is the need to maintain the salt in the molten state throughout the entire process, which requires the implementation of a heat tracing system. Corrosion effects must be monitored primarily at elevated temperatures, where thermal decomposition of the salt may occur, resulting in oxygen release. In the present application, however, local salt overheating is not expected, unlike in systems charged by electrical resistance heating, because the charging medium (nitrogen)

does not exceed 568°C, a temperature at which the rate of chemical decomposition remains low. The corrosion resistance of stainless steels in nitrate salts is generally good, even at elevated operating temperatures.

4.3.8.3 *Lifetime and reliability*

The service life of molten-salt thermal energy storage systems is generally considered to be high, typically on the order of 30 years or more. However, the molten-salt storage systems currently in operation at CSP (Concentrated Solar Power) plants have not yet accumulated such long operating lifetimes. The most significant lifetime-related challenge reported for these systems is the thermomechanical stress experienced by storage tanks, which can lead to cracking and subsequent salt leakage. This issue must be mitigated through appropriate tank design and engineering practices. The long-term degradation of nitrate salts is relatively low, and therefore the salt does not require frequent replacement or purification. Likewise, the service life of system components is not expected to be significantly limited by the storage medium. Overall, the long service life of thermal energy storage (TES) systems can be considered a major advantage compared with other energy storage technologies, particularly electrochemical storage systems.

4.3.8.4 *Components availability*

A large portion of the required components is derived from concentrated solar power (CSP) technology and is readily available on the market. These include thermal storage tanks, molten-salt pumps, valves, electrical equipment, and related balance-of-plant systems. Likewise, the discharge section, comprising heat exchangers between the molten salt and the water-steam circuit, can be implemented using existing technologies and sourced from multiple suppliers. A particular challenge may arise in the charging section, namely the heat exchangers between the nitrogen of the secondary circuit and the molten salt. First, this represents a non-standard application and a technology that has not yet been demonstrated at large scale. Second, the presence of a gaseous medium on the hot side of the heat exchanger results in a relatively low convective heat transfer coefficient. Consequently, larger heat transfer surfaces, greater material requirements, and higher capital costs are expected. The design of this subsystem is beyond the scope of the present project; however, it will require significant attention and further development in future work.

4.3.8.5 *Economic parameters*

The economic parameters reported in the literature are often outdated and inaccurate, and in practice the capital costs of key components are frequently higher than estimated. It cannot be claimed that the implementation of molten-salt thermal energy storage (TES) is a low-cost undertaking; on the contrary, it is expected to have a significant impact on the overall capital investment costs. Given the limited number of technology suppliers, as well as the relatively small number of suppliers capable of providing nitrate salts at large scale, market conditions can change rapidly, and the risk of budget overruns should not be underestimated.

Another important consideration is operating expenditure (OPEX). However, its impact is expected to be less significant in a nuclear power plant application than in many other energy storage applications. A major component of operating costs is the need for dedicated operators and maintenance personnel, unlike electrochemical battery systems, which typically require minimal operational staffing. In the case of a nuclear power plant, however, continuous staffing is already an inherent requirement of plant operation. Consequently, the additional OPEX associated with TES operation may be relatively low.

4.3.8.6 *Nuclear safety*

A key area for further development is the impact on nuclear safety. Nuclear safety must be ensured to the greatest possible extent, and neither the operability of nuclear systems nor the reactor heat removal capability may be adversely affected under any circumstances, including off-normal and accident conditions. Safety assessment is a complex undertaking that requires a broad range of activities, including probabilistic safety assessment, analytical studies, and experimental investigations. These activities must also be incorporated into the economic evaluation of the project, since the current lack of practical experience with the application of TES systems in nuclear power plants implies that substantial effort will be required to demonstrate their safety and support the licensing process.

5 OPERATIONAL REGIMES

The integration of the Thermal Energy Storage system into the power conversion cycle serves a single overarching purpose: to decouple the electrical output of the plant from the constant thermal output of the reactor. While the reactor and the secondary circuit operate continuously at their nominal parameters, the TES acts as a thermal buffer — absorbing part of the secondary circuit's heat when electricity is of low value and releasing it to boost steam production when electricity is of high value. The extent to which this is possible is not arbitrary; it is fundamentally governed by the thermodynamic and mechanical constraints of the power block components. The achievable range of operating regimes is a direct function of the steam turbine's turndown ratio and maximum overload capacity, modelled here as 30% to 110% of its nominal power, together with the requirement that the energy stored during charging must equal the energy released during discharging. These engineering boundaries define the admissible combinations of charging and discharging powers and durations, formalised in the governing equations of Section 5.1.

Within these boundaries, the choice of a specific operational regime is driven by the dispatch strategy. Two primary strategies exist: consumption-following (load-following), which aims to track the daily electrical demand curve, and price-following (economic dispatch), which times the TES operation to the day-ahead electricity market — charging during low-price hours and discharging during price peaks. Although load-following is technically feasible with the proposed system, the present analysis focuses exclusively on the economically more relevant price-following strategy, which directly maximises the plant's daily revenue in volatile modern energy markets. The analysis is based on real day-ahead hourly price profiles from four Central European countries — Poland, Hungary, the Czech Republic and Slovakia (Section 5.2) — and compares two operational philosophies: a Single Cycle regime, with one continuous charging and one continuous discharging period per day (Section 5.3), and a Multi-Cycle regime, which permits multiple switching events to capture all intraday price fluctuations (Section 5.4). The two regimes are compared in terms of achievable daily revenue and their practical implications in Section 5.5.

5.1 Methodology and Governing Equations

The techno-economic analysis of the price-following operation rests on a compact set of governing equations that link the thermodynamics of the TES to the mechanical constraints of the power block and, ultimately, to the revenue generated on the day-ahead electricity market [21]. The model is built on the following assumptions: (i) the reactor and the secondary Brayton cycle operate continuously at their nominal thermal power, so that the power delivered by the secondary circuit to the tertiary side, P_2 , is constant; (ii) thermal losses of the storage tanks and piping are neglected over the daily cycle, i.e. the round-trip storage efficiency is taken as unity, which is a reasonable approximation for well-insulated two-tank molten salt systems over a 24-hour horizon; (iii) the conversion efficiency of the tertiary Rankine cycle is assumed identical for heat delivered directly from the secondary circuit and for heat discharged from the TES, since both streams feed the same steam generator train at the same nominal steam parameters; and (iv) within each operating mode the plant runs at a constant power level, so that the daily schedule consists of piecewise-constant charging and discharging blocks aligned with the hourly resolution of the day-ahead market.

5.1.1 Energy balance of the TES

The fundamental principle governing any admissible operating schedule is the energy balance of the storage: over one complete daily cycle, the thermal energy accumulated during charging must equal the energy released during discharging,

$$E_{TES} = \int_{t \in T_c} P_c dt = \int_{t \in T_d} P_d dt,$$

where T_c and T_d denote the sets of charging and discharging hours, and E_{TES} is the usable thermal capacity of the storage. Under the piecewise-constant power assumption,

$$P_c \cdot t_c = P_d \cdot t_d, \quad (1)$$

where P and t are power and time, respectively, and the subscripts c and d refer to the charge and discharge modes of the TES. Equivalently, the ratio of charging to discharging power equals the inverse ratio of the respective durations,

$$\frac{P_c}{P_d} = \frac{t_d}{t_c}. \quad (2)$$

5.1.2 Turbine flexibility constraints

The operational envelope of the plant is bounded by the flexibility of the tertiary steam turbine. Introducing the relative turbine power

$$x_t(t) = \frac{P_{el}(t)}{P_{el,nom}},$$

where $P_{el,nom}$ is the nominal electrical output of the plant, the admissible operating window is

$$x_{t,min} \leq x_t(t) \leq x_{t,max}, \quad (3)$$

with $x_{t,min}$ and $x_{t,max}$ representing the minimum and maximum relative power outputs defined by the turbine manufacturer. In the present study $x_{t,min} = 0.3$ and $x_{t,max} = 1.1$, i.e. the turbine may be turned down to 30% and overloaded to 110% of its nominal power. During charging the electrical output is depressed below nominal, because part of the secondary circuit power is diverted to the TES; during discharging the output is boosted above nominal by the heat released from the storage.

Combining the bounds of Eq. (3) with the energy balance of Eq. (2) yields the maximum allowable ratio of discharging to charging time that the power block can accommodate, referred to as the flexibility limit:

$$f_{limit} = \left(\frac{t_d}{t_c} \right)_{max} = \frac{1 - x_{t,min}}{x_{t,max} - 1}, \quad (4)$$

where the numerator expresses the maximum depth of the output reduction available for charging and the denominator the maximum overload available for discharging. For the assumed turbine limits, $f_{limit} = 0.7/0.1 = 7$, meaning that one hour of maximum-depth charging can sustain at most seven hours of maximum-overload discharging.

5.1.3 Partition of the flexibility range

To maximize the energy shifted within a given schedule, the operation is modeled to exploit the full flexibility range of the steam turbine, $x_{t,\max} - x_{t,\min}$, which must be partitioned between a charging component Z_c and a discharging component Z_d . These dimensionless fractions represent, respectively, the portion of the secondary circuit power diverted to the TES during charging and the portion delivered from the TES during discharging, both normalized by P_2 . Imposing the energy balance in normalized form, $Z_c \cdot t_c = Z_d \cdot t_d$ together with the full-range condition

$$Z_c + Z_d = x_{t,\max} - x_{t,\min},$$

leads to the closed-form expressions

$$Z_d = \frac{x_{t,\max} - x_{t,\min}}{t_d/t_c + 1}, \quad (5)$$

$$Z_c = (x_{t,\max} - x_{t,\min}) - Z_d. \quad (6)$$

Equations (5) and (6) show that the partition of the flexibility range is fully determined by the chosen time split t_d/t_c : long discharging periods imply a small discharge boost and a deep charging reduction, and vice versa.

5.1.4 Plant power flows

The fractions Z_c and Z_d determine both the electrical output sold to the grid and the thermal power exchanged with the TES in each mode. During discharging the total plant output is augmented above the nominal level,

$$P_{d,\text{tot}} = P_2 \cdot (1 + Z_d), \quad (7)$$

while during charging it is correspondingly reduced,

$$P_{c,\text{tot}} = P_2 \cdot (1 - Z_c). \quad (8)$$

The thermal power delivered from and to the storage in the two modes follows directly as

$$P_{d,\text{TES}} = P_2 \cdot Z_d, \quad (9)$$

$$P_{c,\text{TES}} = P_2 \cdot Z_c, \quad (10)$$

where P_2 is the power delivered from the secondary (power conversion) cycle. Consistency of Eqs. (9) and (10) with the energy balance, $P_{c,\text{TES}} t_c = P_{d,\text{TES}} t_d$, is guaranteed by construction through Eqs. (5)–(6).

5.1.5 Storage capacity and salt inventory

The required usable capacity of the TES follows from the selected schedule as

$$E_{\text{TES}} = P_{c,\text{TES}} \cdot t_c = P_{d,\text{TES}} \cdot t_d, \quad (11)$$

which makes explicit the capital-cost implication discussed in Section 5.6.2: for a fixed daily energy throughput, schedules with shorter total cycling durations require a smaller storage capacity and hence a smaller salt inventory. The capacity is distributed between the high-temperature (Solar Salt) and low-temperature (Hitec) circuits in proportion to the heat duties of the superheater–evaporator and preheater sections, respectively. The salt mass required in each circuit is obtained from a sensible-heat balance,

$$m_{\text{salt},i} = \frac{E_{\text{TES},i}}{\bar{c}_{p,i}(T_{\text{hot},i} - T_{\text{cold},i})}, \quad i \in \{\text{HT}, \text{LT}\},$$

where $\bar{c}_{p,i}$ is the mean specific heat capacity of the salt over its operating temperature span, equal to $555^\circ\text{C} \rightarrow 320^\circ\text{C}$ for the Solar Salt circuit and $320^\circ\text{C} \rightarrow 160^\circ\text{C}$ for the Hitec circuit. Similarly, the instantaneous salt mass flow rate through the charging or discharging heat exchangers is

$$\dot{m}_{\text{salt},i} = \frac{\dot{Q}_i}{\bar{c}_{p,i}(T_{\text{hot},i} - T_{\text{cold},i})}, \quad (12)$$

with $\dot{Q}_i$ the thermal duty of the respective exchanger in the given mode.

5.1.6 Revenue function

Finally, the total daily income, which serves as the objective function of the optimization, is obtained by integrating the product of the instantaneous electrical output and the electricity price over the 24-hour horizon,

$$R = \int_0^{24} P_{\text{el}}(t) \cdot C(t) dt, \quad (13)$$

where R , P_{el} and C are the revenue, the electrical output of the power plant and the electricity price, respectively. Since the day-ahead market clears in hourly intervals, Eq. (13) is evaluated in discrete form,

$$R = \sum_{i=1}^{24} P_{\text{el},i} \cdot C_i \cdot \Delta t, \quad \Delta t = 1 \text{ h}, \quad (14)$$

$$\int_0^{24} P_{\text{el}}(t) dt = 24 \cdot P_{\text{el,nom}}, \quad (15)$$

where $P_{\text{el},i}$ takes the value $P_{c,\text{tot}}$ in charging hours and $P_{d,\text{tot}}$ in discharging hours. It is worth emphasizing that, because the storage is modeled as lossless and the conversion efficiency is common to both heat paths, the total electrical energy sold over the day is invariant with respect to the schedule, as expressed by Eq. (15).

Any revenue gain over the constant-output baseline therefore arises purely from the temporal arbitrage of shifting sales from low-price to high-price hours. The optimization problem addressed in the following sections can therefore be stated compactly as: maximize Eq. (14) over all daily schedules $\{t_c, t_d, \mathcal{T}_c, \mathcal{T}_d\}$ subject to the energy balance of Eq. (1), the turbine window of Eq. (3), and the flexibility limit of Eq. (4). The Single Cycle and Multi-Cycle regimes analyzed below differ only in the topology admitted for the sets $\mathcal{T}_c$ and $\mathcal{T}_d$: the former restricts each to a single contiguous block, while the latter allows an arbitrary number of alternating blocks.

5.2 Dispatch Strategies: Consumption Following versus Price Following

The flexibility envelope defined in Section 5.1 establishes *what* the plant can do; the dispatch strategy determines *when* it should do it. For a nuclear plant equipped with thermal energy storage, two primary dispatch strategies exist, distinguished by the signal that drives the operating schedule: **consumption following** (load following), driven by the physical demand of the power system, and

price following (economic dispatch), driven by the market value of electricity. Both strategies operate within the same physical constraints — the energy balance of Eq. (1), the turbine window of Eq. (3) and the flexibility limit of Eq. (4) — and differ only in the objective according to which the charging and discharging periods are placed within the day.

This subsection describes both approaches, examines the daily profiles of their respective driving signals, and justifies the selection of the price-following strategy for the remainder of the analysis.

5.2.1 Consumption following

Under a consumption-following strategy, the plant modulates its electrical output to track the shape of the daily system demand: the TES is charged when consumption is low and discharged when consumption is high, so that the plant contributes to covering the load precisely when the system needs generation most. Figure 19 presents representative hourly power consumption profiles for the four analyzed countries on a summer weekday. The demand curves share a common, well-known structure: a night-time trough in the early morning hours (around hours 3–5, with the Polish system load falling to approximately 14 GW), a steep morning ramp between hours 6 and 9, an extended daytime plateau (approximately 20–21 GW in Poland, sustained between hours 10 and 15), a secondary evening maximum around hour 21 associated with residential consumption, and a gradual decline towards midnight. A load-following TES schedule maps directly onto this shape: charging during the night-time trough and discharging across the daytime plateau and the evening maximum. The natural performance metric of this strategy is not revenue but a measure of demand coverage, for instance the correlation between the plant output profile $P_{el}(t)$ and the system load profile $D(t)$, or the residual demand left to be covered by other sources. Consumption following is the historically dominant paradigm of dispatchable generation and remains the relevant strategy in regulated markets with cost-based dispatch, in systems where the plant is contractually obliged to provide balancing or capacity services, and in small, weakly interconnected grids where a single unit constitutes a significant share of installed capacity — a situation illustrated by the Slovak system in Figure 19, whose peak load of approximately 4 GW is only two orders of magnitude above the output of the plant analyzed here.

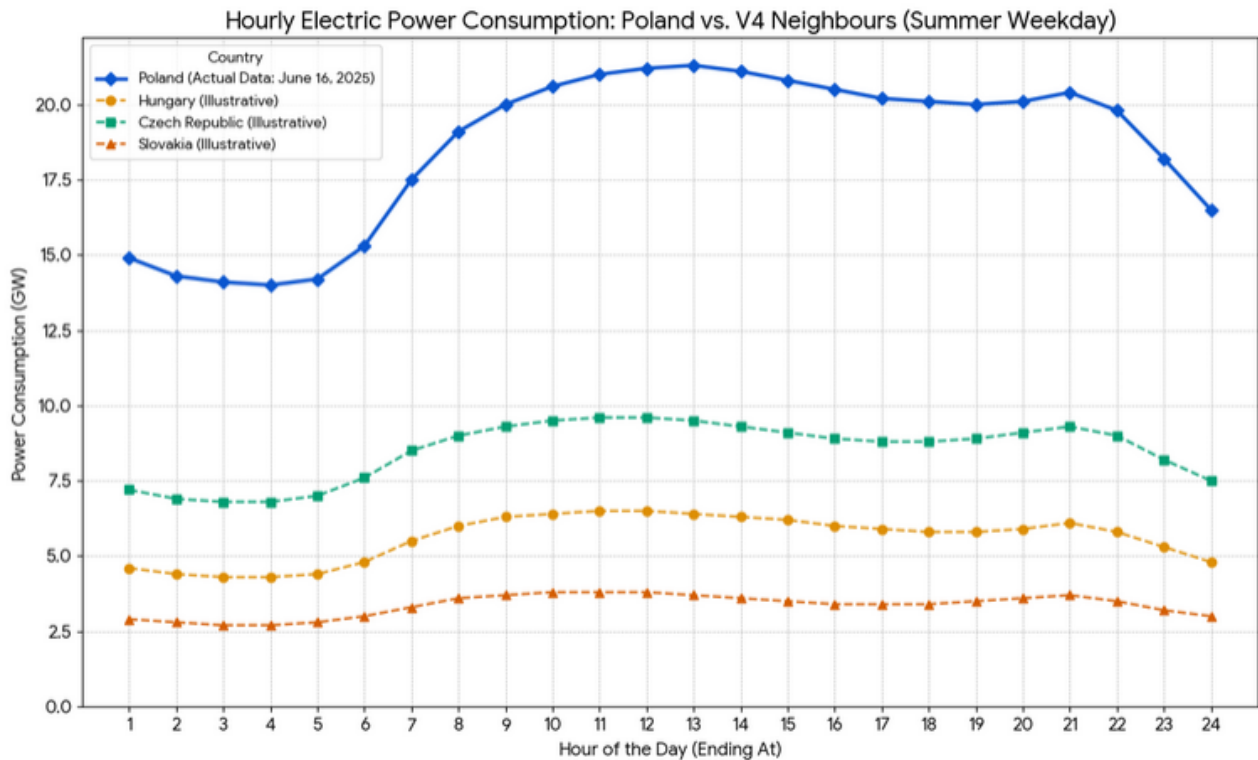


Figure 19 Hourly electric power consumption profiles for Poland and its V4 neighbours on a representative summer weekday. The Polish curve is based on actual system operator data (June 16, 2025); the profiles of Hungary, the Czech Republic and Slovakia are illustrative, scaled to typical national load levels.

5.2.2 Price following

Under a price-following strategy, the operational schedule is driven not by the physical demand but by its economic signal: the day-ahead hourly electricity price. The TES is charged during the hours of lowest market value of electricity and discharged during the price peaks, so that the daily revenue of Eq. (14) is maximized directly. Figure 20 presents representative day-ahead price profiles for the same four countries. Only three distinct curves are visible: Hungary and Slovakia are both significant players in the Central European power market, with integrated electricity markets and strong interconnectedness with their neighbors, and their prices coincide almost exactly throughout the day. All markets exhibit the characteristic double-peak structure of systems with high photovoltaic penetration: a morning peak around hours 7–9, a pronounced midday depression driven by solar infeed — reaching approximately zero for several consecutive hours in Poland, and 15–50 €/MWh in the other markets — and a dominant evening peak around hours 19–21, where prices reach approximately 125 €/MWh in Poland and up to 250 €/MWh in the Czech Republic. The intraday price spread, from roughly 125 €/MWh in Poland to more than 200 €/MWh in the Czech Republic, determines the theoretical upper bound of the arbitrage value that the TES can capture in each market.

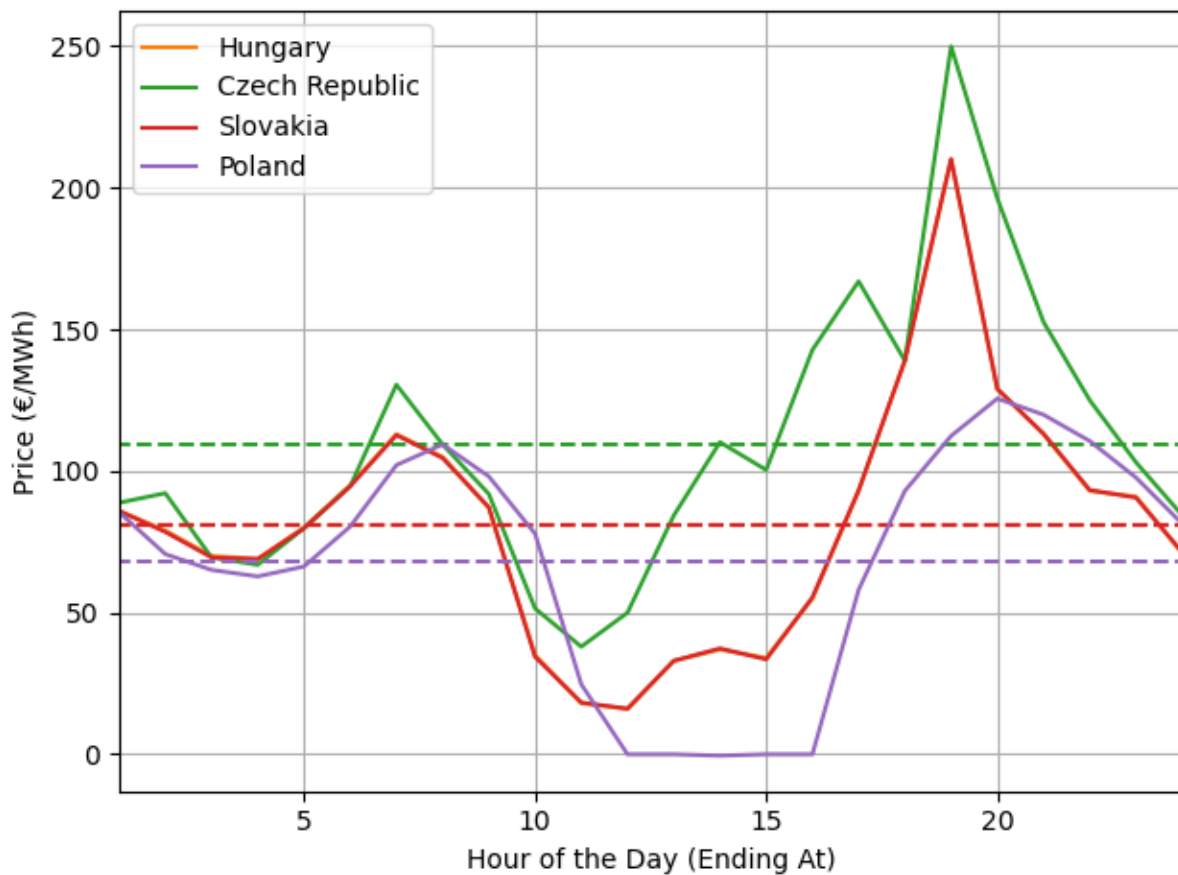


Figure 20 Example daily change of day-ahead electricity prices for the four analyzed Central European markets.

5.2.3 Divergence of the two signals and strategy selection

In a power system without significant variable renewable generation, the two strategies would be nearly equivalent: prices broadly follow demand, so a schedule optimized against one signal would closely approximate the schedule optimized against the other. A comparison of Figures 19 and 20, however, demonstrates that this equivalence no longer holds in Central European markets. The large-scale penetration of photovoltaics has decoupled the price profile from the demand profile, and the two signals now diverge most strongly precisely where the dispatch decision matters most. Between

hours 11 and 15 the Polish system load is at its daily *maximum* of approximately 21 GW, yet the day-ahead price over the same interval collapses to approximately zero, because the solar infeed displaces the entire flexible generation stack. Conversely, the pronounced evening price peak occurs at hours 19–21, when demand has already fallen several gigawatts below its midday level but solar generation has vanished. The two strategies therefore issue opposite commands for the midday window: a load-following plant would discharge its storage into the hours of highest demand — and lowest market value — leaving little or no stored energy for the most valuable evening period, whereas a price-following plant identifies the same window as a charging opportunity and reserves its full discharge capacity for the evening peak.

Two conclusions follow. First, in a liberalized, energy-only market, consumption following is economically penalized: it systematically sells energy at below-average prices and forfeits a substantial share of the achievable arbitrage revenue, without being remunerated for the system service it implicitly provides. Second, since any load-following schedule is merely a different placement of charging and discharging blocks within the same flexibility envelope of Section 5.1, the methodology developed in this work could be applied to consumption-following operation without modification, simply by exchanging the objective function — a relevant option for regulated environments or for future markets with explicit capacity remuneration. For the present analysis, however, which targets the economic viability of the GFR–TES concept in the liberalized Central European markets, the remainder of this study focuses exclusively on the economically more relevant price-following strategy.

5.3 Single Cycle Operation

Single Cycle Operation is defined as a regime consisting of one continuous charging period and one continuous discharging period within a 24-hour horizon. This approach prioritizes operational simplicity and robustness: it is designed to shift a single, large block of energy from the low-price hours to the main price peak of the day, while minimizing the number of mode-switching events and, consequently, the thermal cycling imposed on the salt loops, heat exchangers and steam turbine.

5.3.1 Optimization algorithm

The Single Cycle analysis utilizes a straightforward algorithm to identify the most profitable daily operating schedule. The methodology is based on a “cut-off” price C_{cut} , which serves as a dynamic threshold for switching between the charging and discharging modes: the plant charges the TES whenever the market price falls below the threshold and discharges whenever the price meets or exceeds it,

$$P_{\text{el}}(t) = \begin{cases} P_{c,\text{tot}} & \text{if } C(t) < C_{\text{cut}}, \\ P_{d,\text{tot}} & \text{if } C(t) \geq C_{\text{cut}}, \end{cases}$$

where $P_{c,\text{tot}}$ and $P_{d,\text{tot}}$ follow from Eqs. (8) and (7). For each candidate threshold, the resulting time split (t_c, t_d) is obtained by counting the hours in each mode, and the corresponding power levels are recalculated from the energy balance of Eq. (1) and the partition relations of Eqs. (5)–(6).

The optimal cut-off price is identified through a systematic iterative search that scans the entire domain of observed daily electricity prices. The algorithm discretizes the price range — bounded by the daily market minimum and maximum — and evaluates each increment as a potential switching threshold. For every candidate, the 24-hour horizon is segmented into charging and discharging intervals, the total daily revenue is calculated from Eq. (14), and schedules violating the flexibility limit of Eq. (4) are discarded. The threshold yielding the maximum admissible revenue is selected for each country. The resulting profit landscapes as a function of the cut-off price are presented in Figure 21; the curves are generally flat-topped, indicating that the optimum is robust with respect to moderate variations of the threshold.

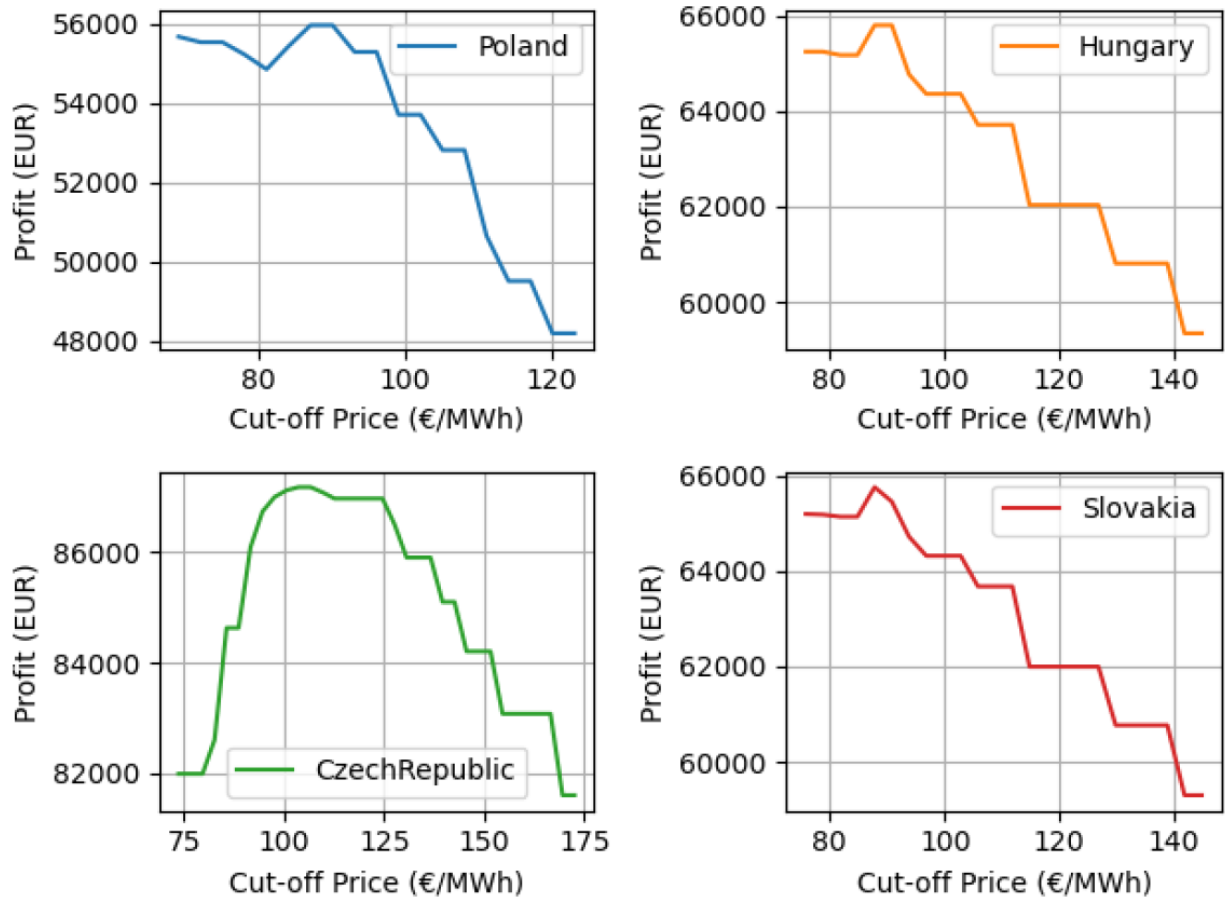


Figure 21 Simulated daily profit as a function of the cut-off price for the four analyzed markets.

5.3.2 Results

The optimal Single Cycle parameters for all four markets are summarized in Table 15. Figure 22 depicts the resulting operating schedules for Poland and the Czech Republic, plotted against the corresponding daily price profiles. These two markets were selected for graphical presentation as they represent the most contrasting outcomes of the subsequent Single/Multi-Cycle comparison; the schedules for Hungary and Slovakia follow qualitatively similar patterns. In the figure, the solid line represents the electrical power delivered to the grid: the low power level corresponds to the TES charging regime and the high level to the discharging mode.

Table 15 Summary table for all countries for single operational regimes.

Parameter	Poland	Hungary	Czech Rep.	Slovakia
t_c [h]	18	17	17	17
t_d [h]	6	7	7	7
$P_{c,el}$ [MW]	24	23	23	23
$P_{d,el}$ [MW]	48	47	47	47
$P_{c,TES}$ [MW]	15	17.5	17.5	17.5
$P_{d,TES}$ [MW]	45	42.5	42.5	42.5
Daily profit [k€]	53.2	63.9	86.3	63.8

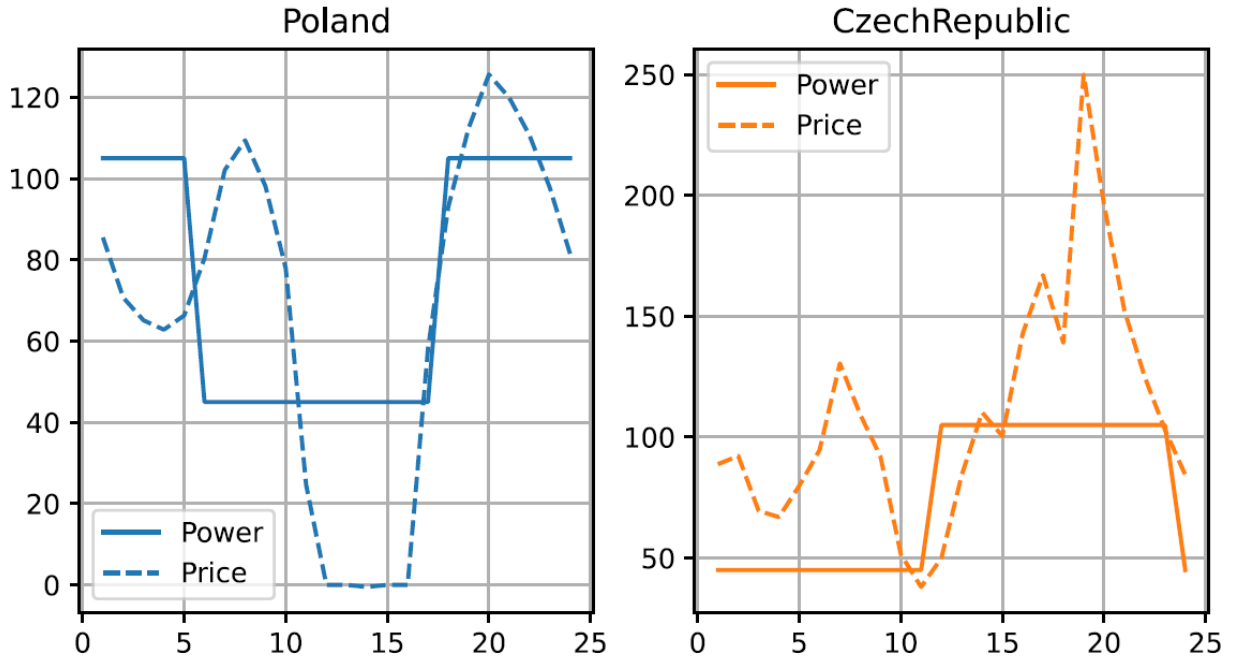


Figure 22 Single Cycle optimal operating schedules plotted against the daily price profile for Poland and the Czech Republic.

The results reflect the structural differences between the markets identified in Section 5.2.2. In all four countries the optimizer converges to a long charging period of 17–18 hours combined with a short, high-power discharging block of 6–7 hours centered on the dominant evening price peak; the discharge-to-charge time ratio of approximately $t_d/t_c \approx 0.35$ – 0.41 lies well within the flexibility limit of Eq. (4), confirming that the turbine constraints are not binding for this regime. It can be verified that each schedule satisfies the energy balance of Eq. (1); for Poland, for instance, $15 \text{ MW} \times 18 \text{ h} = 45 \text{ MW} \times 6 \text{ h} = 270 \text{ MWh}$ of thermal energy is cycled through the TES daily. The extended zero-price midday window in the Polish market favors the longest charging period of the set, whereas the Czech market, despite a similar schedule, achieves the highest daily profit (86.3 k€) owing to its substantially larger intraday price spread and, in particular, the evening peak reaching approximately 250 €/MWh.

Hungary and Slovakia, whose price profiles nearly coincide, yield practically identical optima, differing only in the rounding of the daily profit (63.9 versus 63.8 k€).

The Single Cycle regime thus establishes a robust revenue baseline achieved with only two mode-switching events per day. Whether the additional intraday price structure — most notably the morning peak preceding the midday depression — can be monetized by allowing multiple cycles per day is examined next.

5.4 Multi-Cycle Operation

While the Single Cycle operation provides a robust baseline, its defining restriction — one contiguous charging block and one contiguous discharging block per day — prevents it from monetizing the full intraday price structure identified in Section 5.2.2. In particular, the morning price peak preceding the midday depression cannot be served without sacrificing the far more valuable evening peak. Multi-Cycle Operation removes this restriction: charging and discharging are allowed to occur multiple times throughout the day, so that the plant can flexibly switch between modes whenever the price signal makes it profitable to do so.

5.4.1 Optimization algorithm

The Multi-Cycle schedules are identified by a Fixed-Duration Combinatorial Search, which differs conceptually from the single cut-off price strategy of Section 5.3 and proceeds in three steps.

First, a fixed split of the 24-hour horizon into total daily charging and discharging durations is assumed (e.g., $t_c = 9$ h of charging and $t_d = 15$ h of discharging). For this pre-defined time split, the constant power levels in each mode are computed from the energy balance of Eq. (1) and the partition relations of Eqs. (5)–(6), so that every candidate schedule satisfies both the storage energy balance and the turbine flexibility constraints of Eq. (3) by construction. Note that, in contrast to the Single Cycle algorithm — where the time split is a *result* of the chosen cut-off price — here the time split is an input and no price threshold is defined.

Second, for the given durations, the algorithm performs a combinatorial search, systematically evaluating all admissible placements of the charging and discharging hours across the daily price curve; the individual hours of each mode may be distributed in an arbitrary number of non-contiguous blocks. For each candidate placement, the complete 24-hour power output profile is generated and the total daily revenue is evaluated from Eq. (14). The placement yielding the maximum revenue is retained as the optimum for that specific time split.

Third, the entire procedure is repeated for the full range of feasible time splits — bounded by the flexibility limit of Eq. (4) — and the overall optimal strategy is identified as the combination of duration split and hourly placement that results in the absolute maximum daily revenue.

5.4.2 Results

The optimal Multi-Cycle parameters for all four markets are summarized in Table 16, together with the revenue ratio relative to the Single Cycle optimum of Section 5.3. Figure 23 illustrates the final optimized schedules for Poland and the Czech Republic; the results for Hungary and Slovakia are qualitatively similar and are reported numerically only.

Table 16 Multi-Cycle optimal operating schedules plotted against the daily price profile for Poland and the Czech Republic

Parameter	Poland	Hungary	Czech Rep.	Slovakia
t_c [h]	15	14	14	14
t_d [h]	9	10	10	10
$P_{c,el}$ [MW]	21	20	20	20
$P_{d,el}$ [MW]	45	44	44	44
$P_{c,TES}$ [MW]	22.5	25	25	25
$P_{d,TES}$ [MW]	37.5	35	35	35
Daily profit [k€]	55.9	65.7	87.1	65.7

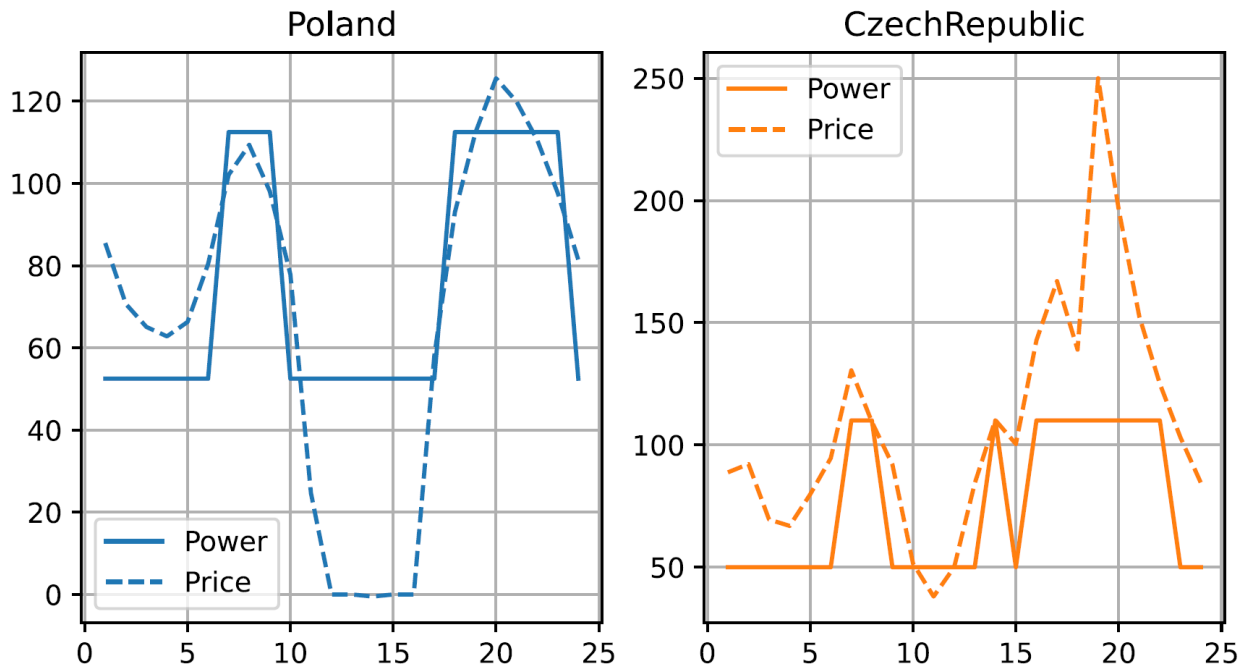


Figure 23 Multi-Cycle optimal operating schedules plotted against the daily price profile for Poland and the Czech Republic.

Compared to the Single Cycle optima, the Multi-Cycle solutions shift towards a more balanced time split: the total charging duration shortens from 17–18 h to 14–15 h and the discharging duration lengthens correspondingly from 6–7 h to 9–10 h, with the additional discharging hours deployed against the morning price peak. As visible in Figure 23, the optimal Polish schedule discharges into both the morning peak (around hours 6–8) and the evening peak, while concentrating the charging in the zero-price midday window and the cheap night hours; the Czech schedule follows the same pattern with an additional brief charging interval in the late-morning price dip. The rebalanced time split implies, through Eqs. (5)–(6), a deeper charging power and a milder discharge boost: the thermal charging power increases from 15–17.5 MW to 22.5–25 MW, while the discharging power decreases from 42.5–45 MW to 35–37.5 MW. The energy balance of Eq. (1) remains satisfied for every schedule; for Poland, $22.5 \text{ MW} \times 15 \text{ h} = 37.5 \text{ MW} \times 9 \text{ h} = 337.5 \text{ MWh}$ of thermal energy is now cycled through the TES daily — a higher daily throughput than in the Single Cycle regime. It should be emphasized, however, that the required storage *capacity* of Eq. (11) is not determined by the daily throughput but by the largest energy content accumulated between mode switches; since the Multi-Cycle schedule alternates between charging and discharging several times per day, the storage is partially emptied and refilled within the day, and the maximum state of charge — and hence the required tank volume and salt inventory — is smaller than in the Single Cycle regime, which accumulates the entire daily throughput in one continuous block.

The revenue gain of the Multi-Cycle strategy is consistent across all four markets but modest in magnitude, ranging from approximately 1% for the Czech Republic to 5% for Poland. The ordering of the gains directly reflects the price structures of Section 5.2.2. Poland benefits most because its profile combines the two features that reward intraday switching: a morning peak of significant height relative to the daily average, and a midday window of essentially zero prices in which the opportunity cost of charging vanishes. In the Czech market, by contrast, the evening peak dominates the daily profile so strongly that the Single Cycle schedule already captures the bulk of the available arbitrage value, leaving only a marginal residual (0.8 k€ per day) for the more complex strategy. Hungary and Slovakia, with their nearly identical prices, again yield practically identical results (ratio 1.03).

The Multi-Cycle regime therefore offers a consistent but marginal revenue advantage, obtained at the cost of a substantially larger number of mode-switching events per day, each imposing thermal transients on the salt loops, heat exchangers and steam turbine. The techno-economic implications

of this trade-off — higher revenue and smaller storage capacity versus increased component cycling — are discussed in the concluding section.

5.5 Steam Turbine Rating

A careful reading of the preceding sections reveals what at first appears to be a contradiction. The tertiary circuit design of Section 3 arrives at a steam turbine output of 18.8 MW at the nominal, steady-state operating point of the plant. The flexibility framework of Section 5.1, in turn, constrains the steam turbine to operate between $x_{t,\min} = 0.3$ and $x_{t,\max} = 1.1$ of its nominal power. Yet the optimized schedules of Sections 5.3 and 5.4 require the steam cycle to absorb up to $P_{d,\text{TES}} = 45$ MW of additional thermal power during discharge. With the tertiary efficiency of $\eta_{III} = 38.3\%$, the steam turbine output at the deepest discharge reaches:

$$P_{\text{ST,disch}} = \eta_{III}(\dot{Q}_0 + P_{d,\text{TES}}) = 0.383 \cdot (49.1 + 45) \text{ MW} \approx 36 \text{ MW},$$

Where $\dot{Q}_0 = P_{\text{ST,design}}/\eta_{III} \approx 49.1 \text{ MW}_{\text{th}}$ is the steam-cycle heat duty at the steady-state design point. Referred to the 18.8 MW machine of Section 3, this corresponds to approximately 190% of its rating — far outside the declared flexibility window.

5.5.1 The design point is not the nominal rating

The resolution of this apparent inconsistency lies in recognizing that the steady-state operating point of Section 3 and the nominal rating of the installed steam turbine are two distinct quantities, and that the adoption of price-following TES operation requires the latter to be deliberately chosen *higher* than the former. In a conventional plant without storage, the two coincide: the turbine is sized for the steady heat input and operates there continuously. In the GFR–TES concept, however, the very purpose of the storage is to concentrate the constant reactor output into shorter, more valuable delivery periods; the power block must therefore be dimensioned not for the average heat flow but for the *peak* discharge condition. The flexibility window of Section 5.1 must consequently be interpreted as a constraint on the *installed* turbine rating $P_{\text{ST,nom}}$, which becomes a free design parameter linked to the most demanding discharge regime by

$$P_{\text{ST,nom}} \geq \frac{\eta_{III}(\dot{Q}_0 + \max P_{d,\text{TES}})}{x_{t,\max}}. \quad (16)$$

or the deepest discharge of the analyzed schedules ($P_{d,\text{TES}} = 45 \text{ MW}_{\text{th}}$, Single Cycle, Poland), Eq. (16) yields $P_{\text{ST,nom}} \geq 36.0/1.1 \approx 32.8 \text{ MW}$. A steam turbine with a nominal rating of approximately **33 MW** — roughly 1.75 times the steady-state design output — is therefore adopted for the price-following plant. The 18.8 MW operating point of Section 3 is retained unchanged, but it is reinterpreted: it is no longer the nominal rating of the machine, but its *baseline part-load point*, at which the turbine runs at $18.8/32.8 \approx 57\%$ load whenever the TES is idle.

With the rating fixed at $P_{\text{ST,nom}} = 32.8 \text{ MW}$, the relative load $x_t = \eta_{III}(\dot{Q}_0 \pm P_{\text{TES}})/P_{\text{ST,nom}}$ can be evaluated for every operating mode of the optimized schedules; the results are collected in

Table 17.

Table 17 Steam cycle heat duty, turbine output and relative load for all operating modes of the single and multi-cycle regimes, referred to the installed rating of 32.8 MW.

Regime	Mode	$\dot{Q}_{\text{ST}}[\text{MW}_{\text{th}}]$	$P_{\text{ST}}[\text{MW}_{\text{th}}]$	x_t
TES idle (baseline)	N/A	49.1	18.8	0.57

Single, PL	Charge	34.1	13.1	0.4
Single, HU/CZ/SK	Charge	31.6	12.1	0.37
Single, PL	Discharge	94.1	36	1.1
Single, HU/CZ/SK	Discharge	91.6	35.1	1.07
Multi, PL	Charge	26.6	10.2	0.31
Multi, HU/CZ/SK	Charge	24.1	9.2	0.28
Multi, PL	Discharge	86.6	33.2	1.01
Multi, HU/CZ/SK	Discharge	84.1	32.2	0.98

Table 17 confirms that, with the resized machine, all Single Cycle regimes and the Polish Multi-Cycle regime operate strictly within the declared window [0.3, 1.1]; the Polish Single Cycle discharge sits exactly at the overload ceiling, consistent with its role as the sizing case of Eq. (16). One marginal violation is exposed: the deep charging mode of the Multi-Cycle regimes for Hungary, the Czech Republic and Slovakia ($P_{c, \text{TES}} = 25 \text{ MW}_{\text{th}}$) drives the turbine to $x_t = 0.28$, slightly below the 30% floor. Consistency requires the charging thermal power to be capped at

$$P_{c, \text{TES}}^{\max} = \dot{Q}_0 - \frac{x_{t, \min} P_{\text{ST}, \text{nom}}}{\eta_{\text{III}}} \approx 23.4 \text{ MW}_{\text{th}}, \quad (17)$$

which for these three markets implies either a slightly longer charging duration at reduced power or a marginally smaller daily throughput. The effect on the optimized revenue is below one percent and does not alter any of the comparative conclusions; the constraint of Eq. (17) should nevertheless be imposed explicitly in any refined optimization, since it couples the admissible schedules to the chosen turbine rating — the rating and the operating regimes must be selected *jointly*, not sequentially.

5.5.2 Implications

The requirement of an oversized power block is not a peculiarity of this design but a structural feature of any storage concept that shifts a constant heat source into shorter delivery windows, and it carries three consequences that must accompany the economic results of this chapter. First, the additional capital cost extends beyond the turbine itself: the condenser and cooling system must reject approximately $58 \text{ MW}_{\text{th}}$ at peak discharge (compared to $30 \text{ MW}_{\text{th}}$ at the baseline point), and the feedwater train and the discharge-side salt–steam heat exchangers must be dimensioned for the full $94 \text{ MW}_{\text{th}}$ duty. These costs are attributable to the TES system and belong in the levelized cost analysis identified as future work. Second, the plant spends the majority of each day at part load — 57% at baseline and 28–40% during charging — where the real isentropic and cycle efficiencies fall below the nominal 38.3% assumed uniformly in this analysis (assumption (iii) of Section 5.1); the reported revenues are therefore mildly optimistic, and a load-dependent efficiency characteristic should be introduced in a refined model. Third, and conversely, the oversizing is precisely what creates the revenue opportunity: the 1.75 sizing factor is the physical embodiment of the plant's ability to sell 48 MW into the evening price peak from a 30 MW (net, steady-state) unit. The economic case for the TES is thus inseparable from the economics of power-block oversizing, and the optimal sizing factor — here derived from the most profitable schedule, but in general a trade-off between peak-hour revenue and marginal capital cost — constitutes a key design variable for any commercial follow-up unit.

The most consequential observation arising from the implementation of the TES and its operating regimes concerns the very notion of the steam cycle's nominal state. By construction, the optimized schedules partition the entire 24-hour horizon into charging and discharging periods ($t_c + t_d = 24 \text{ h}$); there are no idle hours. The steady-state design point of Section 3 — 18.8 MW , or 57% of the installed

rating — is therefore *never actually visited* during normal price-following operation. It survives only as a bookkeeping reference: the state the plant would occupy if the TES were out of service, and the anchor for the energy balance of Eq. (1). This is not an accident of the particular schedules but a structural consequence of the concept itself: any TES whose purpose is economic dispatch is, by definition, active at all times, and a plant in which the storage were idle for a significant part of the day would represent a pointless investment. In effect, the steam cycle is transformed from a single-design-point machine into a **two-point machine**: it alternates between a boosted regime at approximately 98–110% of the installed rating during discharge and a deeply throttled regime at approximately 28–40% during charging, with the intermediate load range traversed only transiently during mode switches (see Table 17).

This observation has direct consequences for the component design and for the fidelity of the economic results. First, the turbine should not be specified, procured, or optimized for its formal nominal point — which it will never see — but for the two operating points it will actually occupy, weighted by their annual duration: the isentropic efficiency characteristic, the admission mode (throttle versus sliding pressure, the latter strongly favored by the sustained deep part-load operation), the last-stage blading, and the condenser design should all be selected to maximize the duration-weighted performance across the charge/discharge pair rather than the efficiency at 100% load. Second, the uniform cycle efficiency of 38.3% assumed throughout this analysis (assumption (iii) of Section 5.1) is, strictly speaking, the efficiency of a state that never occurs; the realized efficiencies at the two true operating points will differ — moderately above-nominal heat rate at the overload point, substantially degraded at 28–40% load — so that the reported revenues carry a systematic optimistic bias that grows with the fraction of the day spent charging. A load-dependent efficiency characteristic $\eta_{III}(x_i)$ is therefore not a refinement but a necessity for any bankable revenue estimate, and its introduction will itself shift the optimal schedules: since charging hours become thermodynamically more expensive, the optimizer will be pushed towards shorter, deeper charging blocks. Third, the same reasoning extends to the balance of plant: the condenser, feedwater train and salt–steam heat exchangers likewise face a two-point duty (approximately 94 MW_{th} versus 24–34 MW_{th} steam-generator duty) and should be designed for controllability and efficiency across that pair, not for a fictitious mean condition. The economic case for the TES concept is thus inseparable from a power block designed *ab initio* as a flexible, dual-point machine — a design philosophy closer to that of concentrated solar power plants, which face the same duty structure and from which proven engineering solutions can be directly adopted.

5.6 Comparison of Operational Regimes and Discussion

5.6.1 Revenue performance

The Multi-Cycle operation consistently outperforms the Single Cycle regime in every analyzed market, confirming that the additional intraday price structure — primarily the morning peak — carries monetizable value. The gain, however, is marginal: the revenue ratio ranges from 1.01 for the Czech Republic to 1.05 for Poland, with Hungary and Slovakia at 1.03. In absolute terms, the daily advantage amounts to 0.8 k€ (Czech Republic) to 2.7 k€ (Poland). If the representative daily profile were assumed to persist year-round — an extrapolation to be treated with caution, since seasonal price variability is not captured by the present single-day analysis (see

Section 6) — this would correspond to an indicative annual revenue difference of approximately 0.3 to 1.0 M€. The magnitude of the gain is governed by the price structure: it is largest where a secondary price peak of significant height coexists with a deep, extended price trough (Poland), and smallest where a single dominant peak concentrates most of the daily arbitrage value, which the Single Cycle schedule already captures almost entirely (Czech Republic). An important corollary is that the relative merit of the two regimes is market-specific and, by extension, sensitive to the future evolution of price profiles: a further deepening of the solar-driven midday depression and a steepening of the

morning and evening ramps — the ongoing trend in Central European markets — would systematically widen the Multi-Cycle advantage.

5.6.2 Storage sizing and capital cost

The two regimes place markedly different requirements on the TES capacity of Eq. (11). The Single Cycle schedule accumulates its entire daily throughput (270 MWh thermal for Poland) in one continuous block, so the tanks and salt inventory must be sized for the full amount. The Multi-Cycle schedule, despite a *higher* daily throughput (337.5 MWh for Poland), alternates between modes several times per day and therefore partially empties and refills the storage within the day; the required capacity is set by the maximum state of charge reached between mode switches, which is substantially smaller than the daily throughput. Since the molten salt inventory, tank volume and associated infrastructure scale approximately linearly with capacity, the Multi-Cycle regime offers a potentially significant reduction of the initial capital investment — a saving that compounds with its higher revenue in any levelized cost comparison.

5.6.3 Component loading and lifetime

The advantages of the Multi-Cycle regime are purchased with a substantially larger number of mode-switching events per day — six or more transitions instead of two. Each transition imposes thermal and mechanical transients on the salt pumps, valves and heat exchangers, and requires the steam turbine to traverse its load range more frequently. Over a plant lifetime of several decades, the accumulated low-cycle thermal fatigue may translate into shorter component lifetimes, more frequent maintenance and a higher forced-outage risk — costs that do not appear in the daily revenue metric but directly erode the 1–5% advantage. The Single Cycle regime, with its two switching events and long quasi-steady periods, is markedly gentler in this respect. In addition, the higher charging power of the Multi-Cycle optima (22.5–25 MW versus 15–17.5 MW thermal) requires the charging-side heat exchangers and salt mass flow rates of Eq. (12) to be dimensioned for roughly 40–50% larger duties, partially offsetting the capital saving on the storage tanks.

5.6.4 Operational complexity and robustness

Finally, the two regimes differ in their operational and forecasting requirements. The Single Cycle strategy reduces to the choice of a single cut-off price, and the flat-topped profit landscapes of Figure 21 demonstrate that its revenue is robust to moderate errors in that choice — an attractive property under imperfect day-ahead price forecasts. The Multi-Cycle strategy requires the correct hourly placement of several operational blocks, making its marginal gain more sensitive to forecast errors and to intraday deviations between forecast and realized prices; in the limit of poor forecast quality, the realized Multi-Cycle revenue may fall below the Single Cycle baseline.

6 CONCLUSIONS

This deliverable establishes a complete design chain for coupling a thermal energy storage unit to the ALLEGRO gas-cooled fast reactor demonstrator, and quantifies the economic value that such a coupling can deliver. Starting from the 75 MWth primary heat source, the secondary nitrogen Brayton cycle and the tertiary water–steam cycle were designed jointly. Splitting the secondary-to-tertiary heat transfer into separate high- and low-temperature exchangers proved to be the decisive step: it is what allows live steam at 10 MPa and 545 °C to be raised at all, and it additionally recovers 12.1 MW of low-grade heat that would otherwise be rejected to the environment. The resulting power conversion system delivers 30 MW net — 11.2 MW from the secondary circuit at 15.2% and 18.8 MW from the tertiary circuit at 38.3% — at an overall plant efficiency of 40.1%.

Thermal energy storage was retained as the most direct form of storage for this application, since heat is both its input and its output, and a two-tank molten nitrate salt system was selected for its high technology readiness and the commercial availability of its components from concentrated solar power. Solid-media storage was excluded because its air-based heat transfer loop is ill-suited to the high charging and discharging powers required, and latent-heat storage because it does not yet offer a sufficiently reliable solution at the temperatures involved. The reference design combines two molten-salt systems in series: Solar Salt in the high-temperature section, used for evaporation and superheating, and HITEC in the low-temperature section, used for feedwater preheating. This allows 545 °C live steam to be raised from storage at the cost of four tanks; the current estimate is based on 168 MWh, of which 135 MWh is stored in Solar Salt and 33 MWh in HITEC, requiring about 1380 t and 510 t of salt respectively. A simpler single-salt alternative uses Yara Most between 170 °C and 500 °C in two tanks: storing the approximately 730 MWh required by the analysed dispatch schedules would call for some 2700 m³ of salt, about 5200 t, accommodated in two tanks of 2000 m³ each. Because the hot tank is limited to 500 °C, steam raised from storage in this alternative would be cooler than the 545 °C design value.

Based on supplier quotations and including the charging heat exchangers, the capital cost of the reference two-salt system, rated at about 50 MW in charge and discharge, is estimated at about 22.5 M€. For the single-salt alternative, benchmarking against published Carnot-battery studies gives 50–70 M€, of which the steam generator alone accounts for roughly 30% — a reminder that the charge and discharge power rating, not only the stored energy, drives the cost of a two-tank system. The latter estimate should, however, be regarded as a lower bound: it omits the nitrogen-to-salt charging heat exchangers, and current supplier data indicate 100–200 \$/kWhth for a complete system and about 2 \$/kg for the salt. The higher specific cost of the reference system, about 134 €/kWhth against roughly 70–95 €/kWhth for the alternative, is consistent with current supplier data and confirms the substantial uncertainty of any CAPEX figure at this stage. Neither estimate includes the technology qualification, licensing and safety demonstration required on the nuclear island, which are expected to raise costs further by an amount that cannot yet be predicted with confidence. Molten-salt storage is therefore expected to have a significant impact on plant capital cost, and the limited number of technology and salt suppliers adds a risk of budget overrun. The charging heat exchanger itself, a non-standard gas-to-salt unit with a low gas-side heat transfer coefficient that has not been demonstrated at large scale, is the principal technical development need. In the system's favour are an expected service life of 30 years or more, low salt degradation, good compatibility with stainless steels at a charging temperature not exceeding 568 °C, and a modest additional operating cost in a plant that is already continuously staffed.

The analysis of the operating regimes yields the central result. In a liberalised, energy-only market, price-following dispatch is unambiguously preferable to consumption following, because demand and price profiles have decoupled in systems with high photovoltaic penetration; consumption following systematically sells energy at below-average prices and forfeits a substantial share of the achievable arbitrage revenue without being remunerated for the service it provides. Within price-following operation, the Multi-Cycle regime outperforms the Single Cycle regime in every market analysed, but only marginally: daily profit rises from 53.2 to 55.9 k€ in Poland, from 63.9 to 65.7 k€

in Hungary, from 86.3 to 87.1 k€ in the Czech Republic and from 63.8 to 65.7 k€ in Slovakia — a gain of 1% to 5%. Extrapolated with caution, since a single representative daily profile cannot capture seasonal variability, this corresponds to an indicative annual difference of 0.3 to 1.0 M€. The advantage is largest where a secondary morning peak coexists with a deep midday price trough, and smallest where a single dominant evening peak already captures most of the arbitrage value. Because the Multi-Cycle regime requires six or more mode switches per day against two, and because its marginal gain is more exposed to price-forecast error, the simpler Single Cycle regime remains a competitive choice once thermal fatigue and forecast risk are priced in.

The most consequential engineering conclusion concerns the power block rather than the storage. Since the purpose of the TES is to concentrate a constant reactor output into shorter, more valuable delivery windows, the steam turbine must be rated for the peak discharge condition and not for the steady-state design point: a nominal rating of approximately 33 MW is required, 1.75 times the 18.8 MW design output. The 18.8 MW point is thereby demoted to a baseline part-load condition at 57% load which, because the optimised schedules leave no idle hours, is never actually visited. The steam cycle becomes a two-point machine, alternating between roughly 98–110% of rating during discharge and 28–40% during charging, and the turbine, condenser, feedwater train and salt–steam heat exchangers should all be specified for that pair of duties rather than for a nominal condition that does not occur.

Five items are accordingly identified as priority future work: a load-dependent cycle efficiency characteristic, without which the reported revenues retain an optimistic bias that grows with the fraction of the day spent charging; a full levelized cost analysis coupling an updated storage capital cost, including the charging heat exchangers, to achievable revenue, to establish the payback period; the detailed design of the piping and valve arrangement that must manage the variable mass flows during mode switching; the design and qualification of the nitrogen-to-salt charging heat exchanger; and a nuclear safety assessment demonstrating that the storage cannot compromise reactor heat removal under any operating or accident condition, together with the associated licensing effort.

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