

CONCEPTUAL TECHNO-ECONOMIC ANALYSIS OF RETROFITTING A 210 MW THERMAL HEAVY-OIL POWER PLANT WITH A MOLTEN SALT THERMAL ENERGY STORAGE SYSTEM FOR RENEWABLE POWER: A CASE ANALYSIS OF TEC NEGOTINO

KONCEPTUALNA TEHNO-EKONOMSKA ANALIZA OPREME 210 MW TERMALNE ELEKTRARNE NA TEŽKO OLJE S SISTEMOM ZA SHRANJEVANJE TERMALNE ENERGIJE S POMOČJO STALJENE SOLI ZA OBNOVLJIVE ENERGIJE: ANALIZA PRIMERA TEC NEGOTINO

Dragan Minovski¹, Marija Sterjova³³

Keywords: retrofitting, MSTES system, electric salt heater, decarbonization, grid flexibility, analysis variants cases, techno-economic assumptions

Abstract

This study conducts a conceptual techno-economic analysis to explore the possibility of retrofitting a 210 MW thermal heavy-oil power plant, TEC Negotino, with a molten salt thermal energy storage system (a Carnot battery). The proposed approach enables storage of surplus or

³³ Corresponding author: Master's degree student Marija Sterjova, Goce Delcev University, Faculty of Electrical Engineering, Krste Misirkov 10-A, 2000 Stip, North Macedonia, Tel.: +389 32 550 000, E-mail address: marija.22512@student.ugd.edu.mk

¹ Goce Delcev University, Faculty of Electrical Engineering, Krste Misirkov 10-A, 2000 Stip, North Macedonia

curtailed renewable electricity on the grid in the form of thermal energy. This initial exploration involves analysing the sensitivity of annual energy yield, load factor, total investment cost, annual O&M cost and levelized cost of a discharging electricity with varying discharging duration, thermal storage capacity and charging duration. The results demonstrate that the most favorable annual roundtrip efficiencies and lowest levelized cost of discharge electricity were obtained for longer discharge duration (in full load hours). This approach of the possibility of repurposing TEC Negotino not only prioritizes the potential for the comprehensive decarbonization of the thermal power plant, but also conserving the majority of jobs within the power plant, making it a sustainable and economically viable initiative.

Povzetek

Ta študija izvaja konceptualno tehnično-ekonomsko analizo za raziskovanje možnosti naknadnega opremljanja 210 MW termoelektrarne na težko olje, TEC Negotino, s sistemom za shranjevanje toplotne energije iz staljene soli (Carnotova baterija). Predlagani pristop omogoča shranjevanje presežne ali okrnjene obnovljive električne energije v omrežju v obliki toplotne energije. To začetno raziskovanje vključuje analizo občutljivosti letnega donosa energije, faktorja obremenitve, skupnih naložbenih stroškov, letnih stroškov O&M in izravnanih stroškov odvajanja električne energije z različnim trajanjem praznjenja, kapaciteto toplotnega shranjevanja in trajanjem polnjenja. Rezultati kažejo, da so bili najugodnejši letni povratni izkoristki in najnižji izravnani stroški električne energije za praznjenje doseženi pri daljšem trajanju praznjenja (v urah polne obremenitve). Ta pristop možnosti ponovne namembnosti TEC Negotino ne daje prednosti le potencialu celovite dekarbonizacije termoelektrarne, temveč tudi ohranjanju večine delovnih mest v elektrarni, zaradi česar je to trajnostna in ekonomsko uspešna pobuda.

1 INTRODUCTION

In the pursuit of cost-effective and strategically aligned energy transition, this paper proposes repurposing a conventional fossil fuel power plant through the integration of a utility-scale molten salt thermal energy storage (MSTES) system, known as the large Carnot battery [1]. This transformative approach not only extends the life of fossil fuel plants (giving them a second green life), but also contributes to the green economy and grid flexibility [11] (effectively smoothing out fluctuations from both renewable energy demand and supply, contributing to a sustainable and resilient energy infrastructure). Following in-depth studies [5]-[7] and exploring the potential of repurposing fossil fuel power plants, including Chile's example of a coal plant retrofit with molten salt storage [8], we spotlight TEC Negotino, a 210 MW fossil fuel power plant on the brink of a remarkable transformation.

As a background research, section 2 delves into the expanded applications of MSTES systems for repurposing conventional fossil fuel plants, extending beyond concentrated solar power (CSP) systems to encompass Power-to-Heat (P2H) strategies with renewable energy (solar photovoltaic (PV) and wind power) [5]. This section explores practical examples and initiatives, such as Germany's commitment to repurposing decommissioned coal plants for substantial thermal storage facilities [4]. In section 3, we focus on a conceptual techno-economic analysis (based on assumptions), evaluating the performance and cost of retrofitting the existing conventional power plant TEC Negotino with the integration of MSTES. This involves the incorporation of an

electric salt resistance heater (ERH), thermal storage system and a molten salt steam generator. The analysis examines the sensitivity of annual energy yield, load factor, total investment cost, annual operation and maintenance (O&M) cost, and the levelized cost of discharging electricity with varying the discharging duration, thermal storage capacity and charging duration. In section 4, the Conclusion provides a concise recap of the main results and outcomes of the conceptual analysis on the possibility of retrofitting TEC Negotino with a MSTES system. Additionally, it suggests further recommendations with the next steps in the research.

2 BACKGROUND

During the last decade, a promising solution that has gained traction in recent years is retrofitting fossil fuel plants with CSP and MSTES systems [2], [3]. To expand the application of MSTES from its commercial use with CSP technologies to other renewable energy (RE) technologies such as solar PV and wind turbine plants, the following concepts are being prepared for market implementation [5]:

- Surplus, or curtailed variable RE electricity available in the grid from PV and wind power plants, can be stored as thermal energy (P2H) using electric molten salt heaters during the charging mode of a MSTES system. Subsequently, at discharge, the stored heat is converted back to power (Heat-to-Power - H2P) through a Rankine cycle. Fig. 1 provides a schematic representation of this concept, serving as the initial reference for ongoing analysis throughout the paper.
- Renewable power can be transformed into heat (P2H) through the use of high-temperature heat pumps for charging a MSTES system. Subsequently, during discharge, the stored heat is converted back into power (H2P) through a closed air Brayton cycle.

Fig. 1 illustrates the integration of a high-temperature MSTES system with ERH, thermal energy storage (hot and cold molten salt tank) and molten salt steam generator, to store and convert heat into power when needed [8], [9].

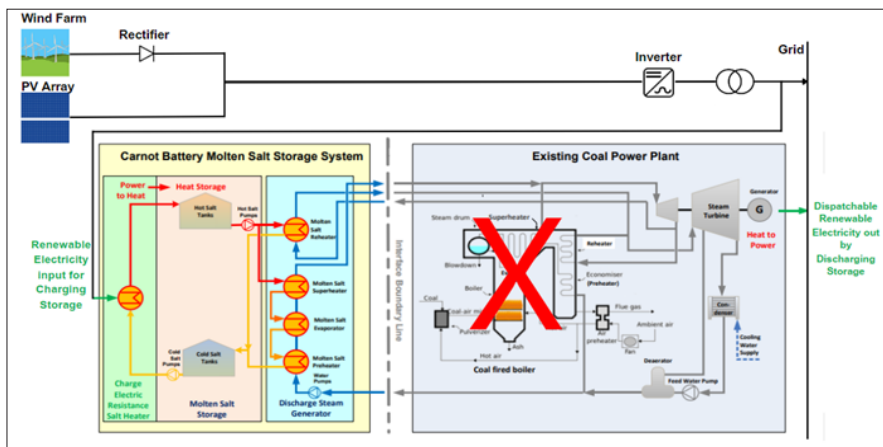


Figure 1: Schematic illustration of the integration of a high-temperature MSTES system into an existing coal plant, making use of its existing Rankine steam cycle

As we can see from Fig. 1, when the power output from both wind and PV systems exceeds the power grid's demand, the surplus electricity is converted into thermal energy by the electric heater and stored in storage system (during the charging cycle shown in Fig. 2). If the power demand exceeds renewable capacity, a steam turbine is activated, utilizing stored heat from the hot tank to generate power (using the existing Rankine steam cycle). Hot molten salt, initially stored in the hot tank, is then pumped to the cold tank, releasing thermal energy which can be used to generate steam for a steam turbine to produce electricity (during the discharging cycle shown in Fig. 2). The process of delivering the stored energy back to the grid is using the former fossil fuel plant's existing infrastructure (power blocks and grid connections). After transferring the hot molten salt to the cold tank, it is then ready to be recharged with thermal energy and the process can begin again. Optional backup co-firing can be used if storage reaches a critical level and cannot provide sufficient energy. The research assumes that the conventional heavy-oil fuel boiler in the case of TEC Negotino is not operational.

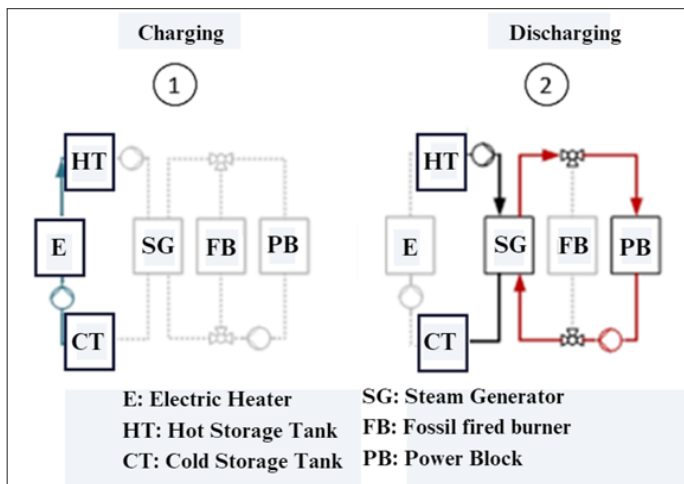


Figure 2: Operating modes of the MSTES of a model without the optional inclusion of fossil fuel boilers [6]

Fig. 3 illustrates examples of typical molten salt heated steam generator systems, including the 6,6 MWe molten salt heaters used at the SQM Nitrate Plant located in Coya Sur, Chile.

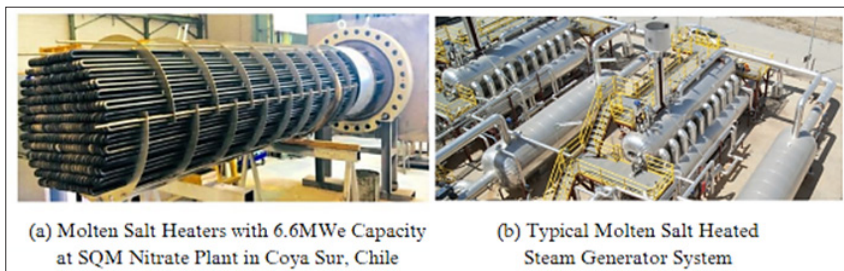


Figure 3: Illustration of a (a) molten salt resistance heaters for charging, and (b) a molten salt heated steam generator [5], [7]

Currently, molten salt, also known as "Solar Salt", a binary mixture of sodium nitrate (60 wt%) and potassium nitrate (40 wt%); (60 wt% NaNO₃ - 40 wt% KNO₃), appears as an efficient and durable energy storage salt composition for MSTES system retrofit applications, due to its high heat capacity, non-flammable and non-toxic properties, and longevity of over 30 years without degradation [7]. Solar Salt has a maximum temperature limit of 565°C, which demonstrates the capability to provide superheated steam up to 550 °C for power generation [2], [5]- [7], [10].

In 2018, the official German government coalition program [4] incorporated the concept of transforming decommissioned coal plants into thermal storage facilities. The program commits the German coalition government to "examine the extent to which power plant sites no longer needed in future may be used for large thermal storage plants" (lines 3321-3322). The German Aerospace Center (DLR) has played a pivotal role in exploring the technical and economic feasibility of incorporating solar technologies and molten salt storage into coal-fired power plants. The successful implementation of concentrated solar power and thermal energy storage technology can be seen in the 110 MW Cerro Dominador CSP project in Chile (formerly Atacama-1). This project showcases the feasibility and potential of similar storage systems in retrofitting retiring coal plants, offering a reliable source of renewable energy [2], [3]. In the context of the broader project "Decarbonization of the Energy Sector in Chile" implemented by the Ministry of Energy and Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH, the publication [8] has been prepared, to explore a preliminary techno-economic analysis of retrofitting a coal plant in Chile (250 MWe net) with a CSP molten salt storage system, resistance heater and molten salt steam generator.

3 CASE ANALYSIS OF RETROFITTING AN EXISTING THERMAL PLANT, TEC NEGOTINO, WITH MOLTEN SALT STORAGE, RESULTS AND DISCUSSION

For the purpose of this conceptual analysis, it's important to highlight that the analysis in this section is based on the use of a typical daily profile. This approach was chosen to enhance our overall understanding, and to make it easier for us to compare different analysis variants, all within and under consistent conditions guided by techno-economic assumptions.

3.1 Technical Assumptions

The study utilizes Fig. 4 as the example configuration used in the techno-economic analysis for the possibility of retrofitting TEC Negotino, a 210 MWe (net) heavy-oil plant. Fig. 4 showcases the integration of an electrical salt heater, thermal capacity storage and a molten salt steam generator in the retrofitting process for TEC Negotino. A crucial step in the retrofitting involved replacing the heavy oil-fired boiler with an efficient molten salt steam generator, utilizing discharge heat from the molten tank storage to power the turbine generator.

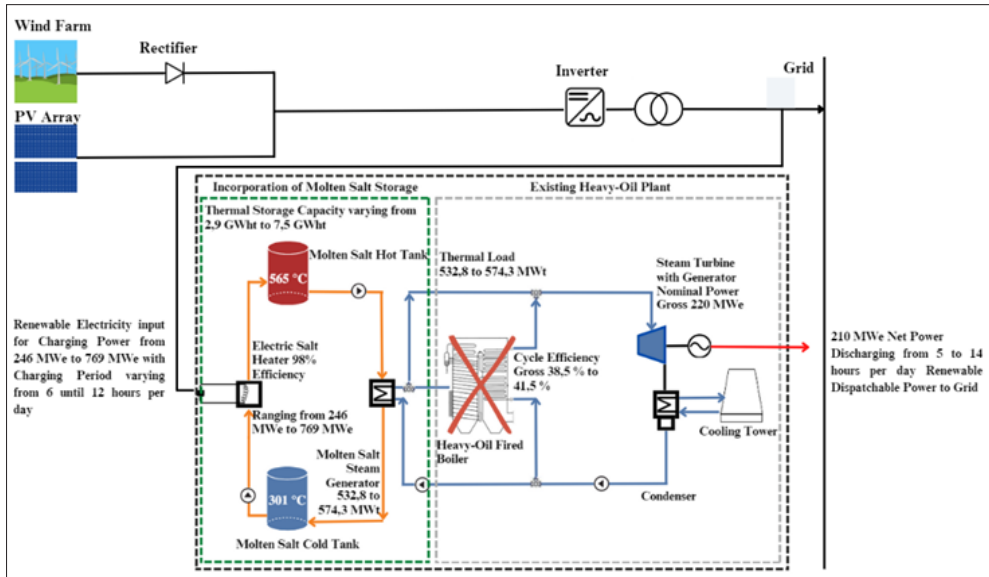


Figure 4: Incorporation of an MSTES system with thermal capacity varying from 2,9 GWht to 7,5 GWht to an existing heavy-oil plant of the 210 MWe class (net) in TEC Negotino – example configuration used in the techno-economic analysis

For the example configuration in Fig.4, the following component efficiencies were considered:

- Electric salt heater with an efficiency of 98%.
- Thermal energy storage tank with an efficiency of 99%.
- Molten salt steam generator with an efficiency of 99,5%.

Regarding the Rankine cycle gross efficiency for all analysis variants (Table 1), they were varied as follows:

- For variants V1-V3, the gross cycle efficiency was 38,5%.
- For variants V4-V7, the corresponding gross cycle efficiencies were 39%, 40%, 41% and 41,5%.

The capacity of the molten salt steam generator is always at full load for the specified discharge hours:

- For variants V1-V3 – constant capacity of approximately 574,3 MWt.
- For variants V4-V7 - capacities of approximately 566,9 MWt, 552,8 MWt, 539,3 MWt and 532,8 MWt, respectively.

Table 1 provides a summary of the sensitivity variants. In the next step, we analysed the sensitivity of annual energy yield, load factor, total investment cost and levelized cost of discharge electricity with varying the discharge duration, thermal storage capacity and charging duration.

Table 1: Sensitivity variants of discharging duration (full load hours), thermal storage capacity, charging duration and capacity of electric salt heaters

Sensitivity variant	Unit	V1	V2	V3	V4	V5	V6	V7
Discharging duration	[hours]	5	5	5	9	11	12	14
Thermal storage capacity	[GWht]	2,9	2,9	2,9	5,2	6,1	6,5	7,5
Charging duration	[hours]	6	8	12	10	11	11	10
Charging electric salt heater capacity	[MWe]	493,283	369,962	246,642	525,916	569,742	606,3774	768,808

At first, the discharging duration was varied, maintaining a constant 5 full load hours for the initial three variants (V1-V3), and extending to 9, 11, 12 and 14 full load hours for variants V4-V7. The corresponding thermal storage capacity ranged constant, with 2900,5 MWht for variants V1-V3; to 5153,98, 6141,8, 6536,75 and 7534,32 MWht for variants V4-V7, resulting in a plant load factor spanning from 20,8% for a 5-hour discharging duration to 37,5%, 45,8%, 50%, and 58,3% for 9, 11, 12 and 14-hour discharging durations, respectively. The plant load factor was determined using the following equation:

$$\text{Plant load factor} = \frac{\text{Average load}}{\text{Maximum demand}} \times 100 \text{ [\%]} \tag{3.1.1}$$

where, for daily calculations,

$$\text{Average load} = \frac{\text{Energy generated per day}}{24} \text{ [MW]} \tag{3.1.2}$$

and maximum demand was a maximum load of 210 MW.

Second, the charging duration, was directly proportional to both the installed capacity of the electric salt heaters and the thermal storage capacity. The charging duration was varied with 6, 8, 12 charging hours for the first three variants V1-V3 varying the corresponding electric salt heater capacity with 493,283, 369,962 and 246,642 MWe. The variants V4-V7 were varied with 10, 11, 11 and 10 charging hours, varying the corresponding electric salt heater capacity from 525,916, 569,742, 606,3774 and 768,808 MWe. The equation representing the conversion of charging electric salt heater power capacity [MWe] to nominal thermal power [MWt] considering the efficiency of the electric salt heater $\eta_{\text{el.salthheater}} = 98\%$ was as follows:

$$\text{Nominal thermal power} = \text{Charging electric salt heater capacity} \times \eta_{\text{el.salthheater}} \text{ [MWt]} \tag{3.1.3}$$

After determining the nominal thermal power, the thermal storage capacity was calculated by multiplying the nominal thermal power by the charge duration t_{charge} [hours], expressed as:

$$\text{Thermal storage capacity} = \text{Nominal thermal power} \times t_{\text{charge}} \text{ [GWht]} \tag{3.1.4}$$

Furthermore, the results encompassed the annual charging and discharging net electricity amounts, alongside the corresponding annual roundtrip charging/discharging efficiencies, which are represented visually in Fig. 5.

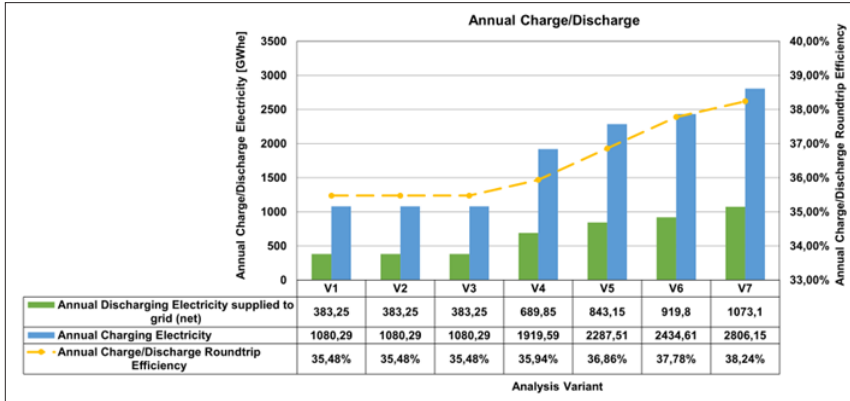


Figure 5: Chart representation of annual charging/discharging electricity and annual roundtrip charging/discharging efficiency for the analysis variants

The annual charging and discharging net electricity are determined based on typical daily profiles for the considered variants, utilizing the following equations:

$$\text{Annual discharge net electricity} = \text{Net power} \times \text{Discharge duration} \times 365 \text{ days [GWhe]} \quad (3.1.5)$$

$$\text{Annual charge electricity} = \text{Charging electric salt heater capacity} \times \text{Charge duration} \times 365 \text{ days [GWhe]} \quad (3.1.6)$$

The roundtrip efficiency ($\eta_{\text{roundtrip}}$) can be calculated using the provided equations for annual discharge net electricity and annual charge electricity. It is calculated as the ratio of the net electricity discharged to the grid over the year to the total electricity for charging the electric salt heater over the year:

$$\eta_{\text{roundtrip}} = \frac{\text{Annual discharge net electricity}}{\text{Annual charge electricity}} \times 100 [\%] \quad (3.1.7)$$

Notably, from Fig. 5, our observations highlighted variants V6 and V7 as the most favorable, achieving the best annual round-trip charging/discharging efficiencies at around 38%.

3.2 Assumptions in Investment Costs (CapEx) and Operation Costs (OpEx)

In this research, specific economic parameters, including investment and operational costs, were sourced from [8]. The key financing and cost parameters are presented in Table 2 and Table 3 for retrofitting molten salt storage in the existing heavy-oil plant TEC Negotino. In the context of this conceptual analysis, we assumed that the existing grid connection requires no modifications. Furthermore, the power plant in focus operates exclusively on non-fossil fuel, eliminating the need for specified fuel costs in our analysis. Moreover, we have set a constant charging rate from the grid at \$20 per megawatt-hour of electricity [MWh] for this analysis, regardless of its origin. In reality, such power is expected to originate primarily from a PV power plant. These assumptions are included in Table 2.

Table 2: Assumed specific investment cost for integrating molten salt storage for retrofitting an existing 210 MWe class heavy-oil plant

Specific investment cost	Unit	Value
Electric heater	[\$/kWe]	100
Storage system	[\$/kWh]	23
Solar salt	[\$/t]	Included in storage
HTF System		
Hot and cold salt pumps	[\$/kWt]	Included in storage
HTF piping system	[\$/kWt]	Included in storage
Heat tracing system	[\$/kWt]	Included in storage
Molten salt steam generator	[\$/kWt]	90
Power block including BOP (existing unit)	[\$/kWt]	0
Integration cost to existing Power Block	[\$/kWt]	10
Modification cost of grid connection	[\$/kWe]	0
Total surcharges (engineering, risk, management)	[%] of direct cost	30
Specific O&M cost		
O&M incl. insurance	[% of direct cost/y]	3
Fuel costs	[\$/MWh]	N/A
Electricity cost for charging	[\$/MWh]	20

Fig. 6 shows the resulting total investment cost for seven different analysis variants (V1-V7).

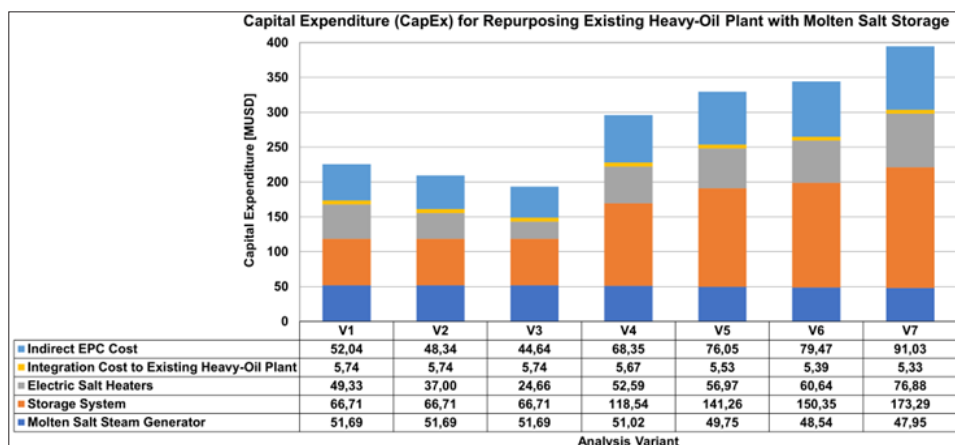


Figure 6: Chart representation of the estimated total investment cost (CapEx) for integrating a molten salt storage system (ERH+storage system+ molten salt generator) for retrofitting the existing heavy-oil plant TEC Negotino for the analysis variants (V1-V7)

In Fig. 6, for the analysis variant cases V1, V2 and V3, the constant capacity for the molten salt steam generator ($574,3 \times 10^3$ KWT) and storage system ($2900,5 \times 10^3$ KWht) (section 3.1) also represents a constant rounded investment cost of 51,69 and 66,71 million USD, correspondingly. The investment cost for the electric salt heater's capacity, varying with $493,283 \times 10^3$, $369,962 \times 10^3$, $246,642 \times 10^3$ KWe (Section 3.1), varied with values of 49,33, 37,00, 24,66 million USD respectively, rounded to two decimal places (also shown in Fig.6).

For the analysis variant cases V4, V5, V6 and V7, the investment cost for the molten salt steam generators capacity varied (Fig.6), with the values of 51,02, 49,75, 48,54 and 47,95 million USD, respectively. These values correspond to the molten salt steam generator's capacity of $566,9 \times 10^3$, $552,8 \times 10^3$, $539,3 \times 10^3$ and $532,8 \times 10^3$ KWT (section 3.1). The investment cost for the molten salt storage system in these analysis variant cases (Fig.6) also varied, with values of 118,54, 141,26, 150,35 and 173,29 million USD, respectively. These values correspond to the thermal storage capacity (in full load storage duration; section 3.1) with $5153,98 \times 10^3$, $6141,8 \times 10^3$, $6536,75 \times 10^3$, and $7534,32 \times 10^3$ KWht. In line with the varying storage capacity and charging duration (10 hour charging duration for V4 and V7; 11 hour charging duration for V5 and V6), the electrical salt heater's capacity is $525,916 \times 10^3$ KWe for V4, $569,742 \times 10^3$ KWe for V5, $606,3774 \times 10^3$ KWe for V6 and $768,808 \times 10^3$ KWe for V7 (section 3.1). These values of the electric salt heater's capacity for analysis variant cases V4, V5, V6 and V7 corresponded with the investment cost of 52,59, 56,97, 60,64 and 76,88 million USD respectively (as shown in Fig.6). The investment costs for individual components are rounded to two decimal places.

The integration cost to the existing heavy-oil plant and indirect EPC cost (30% of the direct cost) were considered for each analysis variant case. The resulting rounded total investment cost was the sum of the individual rounded investment analysis variants costs. The resulting rounded total investment cost (CapEx) for analysis variant cases (V1 to V7), shown in Fig.6, are as follows: 225,51, 209,48, 193,44, 296,17, 329,56, 344,39 and 394,48 million USD, respectively.

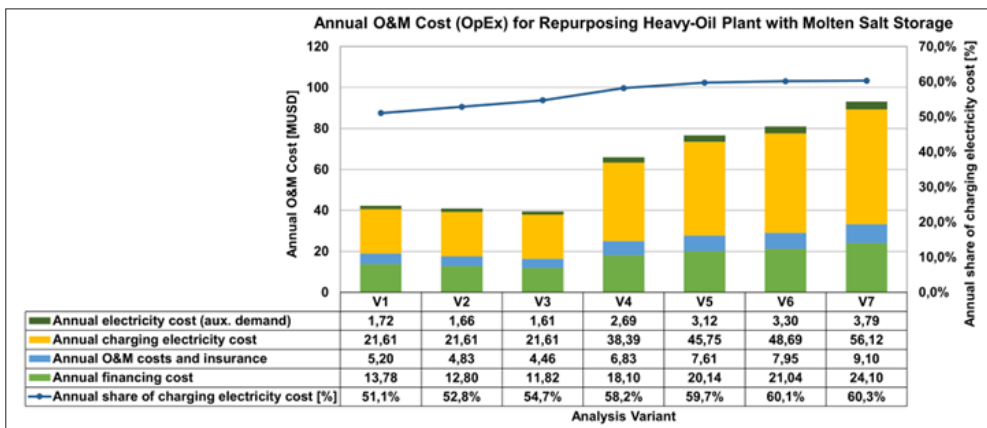


Figure 7: Chart representation of the estimated annual operation cost (OpEx) for integrating the molten salt storage system (ERH+storage system+ molten salt generator) for retrofitting the existing heavy-oil plant TEC Negotino for the analysis variants (V1-V7)

In the calculation of the annual operational cost shown in Fig. 7, the analysis relied on the following preliminary simplified assumptions:

1. A fixed cost of \$20 per megawatt-hour (\$/MWh) for charging electricity (Table 2), which may see a potential reduction in the future, especially when considering dedicated large-scale PV systems for storage charging. Presented in Fig. 7, the annual charging electricity cost varies from a constant value of 21,61 million USD for the first three analysis variants cases (V1 to V3) to 38,39, 45,75, 48,69 and 56,12 million USD for analysis variants cases (V4 to V7).
2. The annual O&M cost, including insurance, were estimated at 3% per annum of the corresponding CapEx. It is crucial to validate this estimate against actual O&M service offers. The annual O&M costs, including insurance, varied, with values of 5,20, 4,83, 4,46, 6,83, 7,61, 7,95 and 9,10 million USD for the analysis variants cases (V1 to V7), as shown in the chart representation in Fig.7.
3. The financing cost was determined through a simplified levelized cost of electricity (LCOE) analysis, assuming complete (100%) financing over a 35-year debt period with a constant real discount rate of 5%. The values presented in Table 3 need to be validated against real project finance offers. From there, the annuity of 6,11% in Table 3 was determined, using the following equation:

$$\text{Annuity} = \frac{i \times (1 + i)^n}{(1 + i)^n - 1} \times 100 \text{ [%]} \quad (3.2.1)$$

Where,

i: periodic discount rate;

n: year debt period. The annual financing cost varied, with values of 13,78, 12,80, 11,82, 18,10, 20,14, 21,04 and 24,10 million USD for the analysis variants cases (V1 to V7), as shown in Fig. 7.

4. The auxiliary power consumption, determined at 4.05% of gross electricity production for our analysis, was used to estimate the cost of auxiliary power by consumption percentage and cost of discharging electricity. Values for the annual electricity cost, presented in Fig. 7, for auxiliary demand, varied with approximately 1,72, 1,66, 1,61, 2,69, 3,12, 3,30 and 3,79 million USD for the analysis variants cases (V1 to V7) .

In Fig. 7, we also observe a significant trend in the share of charging electricity cost in the total annual O&M cost across all seven analysis variants cases (V1 to V7). For the first three analysis variants cases (V1 to V3), with a 5 hour full load discharge duration, the respective share of charging electricity cost was 51,1%, 52,8%, and 54,7%. For the remaining four analysis variants cases (V4 to V7) with 9, 11, 12, and 14 full load discharge durations, the respective share of charging electricity cost was 58,2%, 59,7%, 60,1%, and 60,3%.

3.3 Levelized Cost of Discharge Electricity

Using the results of the energy yield and the annual cost of the power plant, the levelized cost of electricity could be calculated using the defined economic model in Fig. 8. This allows ranking of the various analysis variants cases. Some other economic parameters, such as taxes, project financing concepts, etc. have not been taken into account for this ranking. In our ranking analysis, we've gathered and outlined the financial assumptions in Table 3.

Table 3: Assumed financing data for calculating the levelized cost of discharge electricity

Financing data for LCOE	Unit	Value
Debt period	years	35
Discount rate	%	5,0
Annuity	%	6,11

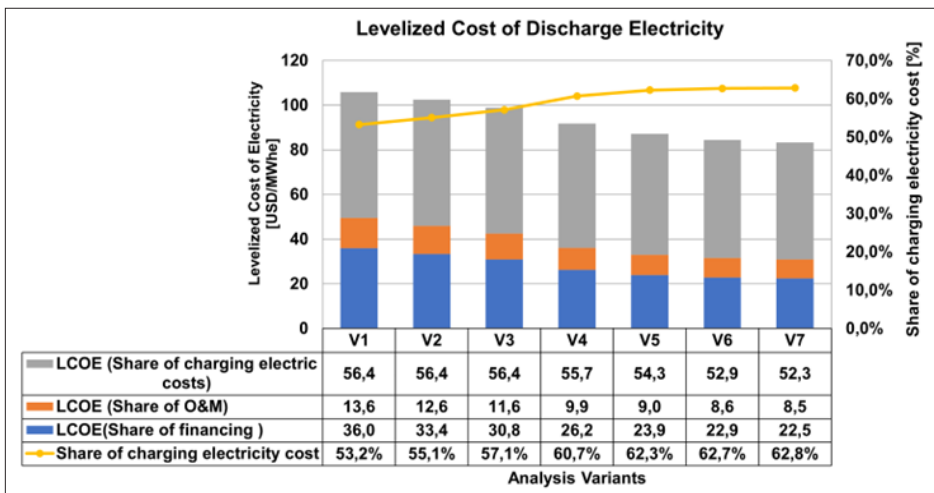


Figure 8: Chart representation of the levelized cost of discharge electricity for integrating a molten salt storage system (ERH+storage system+ molten salt generator) for retrofitting the existing heavy-oil plant TEC Negotino for the analysis variants (V1-V7)

In the analysis of levelized cost of discharge electricity (LCOE) for various analysis variants cases (V1 to V7) considering the potential conversion of the heavy-oil plant TEC Negotino into an MSTES plant, the results depicted in Fig. 8 reveal a distinctive ranking. The LCOE for a 5-hour full load discharge duration falls within the range of approximately 99 to 106 USD/MWhe. However, for longer discharge duration, the LCOE exhibited a decline, reaching approximately 92 USD/MWhe for a 9-hour full load discharge duration (V4), 87 USD/MWhe for an 11-hour full load discharge duration (V5), 84 USD/MWhe for a 12-hour full load discharge duration (V6) and 83 USD/MWhe for a 14-hour full load discharge duration. Additionally, the percentual shares of charging electricity to the overall LCOE is shown in Fig. 8, are 53,2%, 55,1%, 57,1%, 60,7%, 62,3%, 62,7% and 62,8% for the analysis variants cases (V1 to V7).

4 CONCLUSION

In conclusion, it is crucial to emphasize that this study represents a conceptual analysis conducted under consistent conditions, utilizing a typical daily profile for enhanced comparability. The chosen approach provided valuable insights into the techno-economic aspects of the possibility of retrofitting the 210 MW thermal heavy-oil power plant, TEC Negotino, with a molten salt thermal energy storage system (a Carnot battery). The study explores the sensitivity of various parameters, based on the techno-economic assumptions, to estimate the possibility of integrating the proposed system. The results indicate that longer discharging durations, specifically for analysis variants V6 and V7 with 12 and 14 full load hours, resulted in the most favorable annual roundtrip efficiencies and lower levelized cost of discharging electricity. Analysis variants V6 and V7 emerged as particularly promising, achieving around 38% annual roundtrip charging/discharging efficiency and levelized cost of discharging electricity below 90 USD/MWhe, approximately 84 USD/MWhe for a 12-hour full load discharge duration (V6) and 83 USD/MWhe for a 14-hour full load discharge duration (V7). This possibility not only emphasizes the potential for the thorough decarbonization of TEC Negotino, but also focuses on conserving the majority of power plant jobs.

As next steps, it is recommended to conduct a detailed engineering study with a dynamic profile on the proposed retrofitting of a molten salt storage facility with electric salt heaters and molten salt steam generators in the existing heavy-oil plant TEC Negotino, in order to obtain commercial offers and investigate the financing possibilities for such a measure.

References

- [1] **A. Vecchi, K. Knobloch, T. Liang, ..., Y. Ding:** *Carnot Battery development: A review on system performance, applications and commercial state-of-the-art*, Journal of Energy Storage, Vol. 55, Part D, 2022
- [2] **M. Geyer:** *CSP and Thermal Energy Storage*, Seminario "Concentración Solar de Potencia, una Opción Clave para la Transición Energética" Santiago de Chile, April 25, 2019
- [3] **World Bank:** *Concentrating Solar Power: Clean Power on Demand 24/7*, Washington, DC, 2021
- [4] **Koalitionsvertrag zwischen CDU, CSU und SPD**, 2018
- [5] **M. Geyer, C. Prieto:** *20 - Storing energy using molten salts*, Storing Energy (Second Edition), p.p. 445-486, 2022
- [6] **W. Arnold, S. Giuliano, T. Bauer, M. Geyer, DLR, RWE, ..., S. Zunft:** *StoreToPower: Stromspeicherung in Hochtemperatur-Wärmespeicherkraftwerken*, öffentlicher Abschlussbericht, p.p. 1-161, 2022
- [7] **M. Geyer, S. Giuliano:** *Conversion of Existing Coal Plants Into Thermal Storage Plants*, Applied Sciences, In: Luisa F. Cabeza (eds.), Encyclopedia of Energy Storage, Vol. 2, p.p. 122-132, 2022

- [8] **M. Geyer, F. Trieb, S. Giuliano:** *Reconversión de centrales a carbón en plantas de almacenamiento térmico con energía renovable en Chile*, Executive Summary, p.p. 1-27, 2020
- [9] **J. Li, W. Qi, J. Yang, Y. He, J. Luo, S. Guo:** *The Capacity Optimization of Wind-Photovoltaic-Thermal Energy Storage Hybrid Power System*, ICAEER, E3S Web of Conferences 118, 02054, 2019
- [10] **T. Bauer, C. Odenthal, A. Bonk:** *Molten Salt Storage for Power Generation*, Chemie Ingenieur Technik, Vol.93 (4), p.p. 534-546, 2021
- [11] **Gibb et al. from the German Aerospace Center (DLR):** *Applications of Thermal Energy Storage in the Energy Transition – Benchmarks and Developments*, , IEA Technology Collaboration Programme on Energy Conservation through Energy Storage (IEA-ECES), 2018