**ECONOMIC ANALYSIS OF THERMAL ENERGY**

**STORAGE INTEGRATION IN SMALL MODULAR**

**REACTORS BALANCE OF PLANT**

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**Abstract**

The increasing penetration of renewable energy sources in the electric grid intensifies more than ever the demand for adjustable power outputs. Nuclear plants often find load-following, though feasible, undesirable especially due to the associated thermo-mechanical stresses on reactor components. To help absorb the load variability and improve the overall plant economics we can integrate molten salt thermal energy storage (MSTES) into a Small Modular Reactor (SMR) balance-of-plant (BOP). This study assesses the economic viability of this approach through a discounted cash flow analysis. In particular, this work considers a lead-cooled SMR with an electrical capacity of about 120 MWe, 3 different MSTES tank sizes, and 6 BOP configurations for loading and unloading the molten salt at different rates. By storing excess thermal energy during low-demand periods and releasing it during peaks, it is possible to meet fluctuating energy needs and improve overall revenues. The paper provides net present values for the proposed systems by considering capital costs, operating expenses, revenue streams, and discount rates. The results show which configurations could be the most economically profitable, underlying the need for such preliminary analysis to drive the design of nuclear systems adopting MSTES.

1. INTRODUCTION

In the last decades, the electricity share produced globally by renewable sources has rapidly increased, by 340 GWe in 2022 alone [[1]](#Segnalibro1). Given their intermittency, the ability to modulate electricity output to quickly react to supply and demand variability is becoming increasingly valuable [[2]](#Lund2007_2). This is especially true for base-load power plants such as natural gas, coal, and nuclear ones (NPPs). However, load following with NPPs is usually avoided for both technical and economic reasons. Despite the good maneuverability of recent NPPs [[3]](#NEA2011_3), frequent power changes can increase thermo-mechanical stresses among reactor components [[3]](#NEA2011_3). Moreover, NPPs are capital intensive: reducing the power output decreases revenues and extends the time to recover the capital investment [[3](#NEA2011_3), [4]](#Locatelli2015_4).

One possibility to enhance the load following capability and economics of NPPs is to couple it with an energy storage plant. In principle, the reactor would produce a constant power output: during periods of low demand and low electricity price, its excess can be stored to sell during high price and high demand periods [[5]](#Coleman2017_5), the so-called ‘price arbitrage’. This work addresses the technical availability and economic performance of such configurations, focusing on a Gen-IV small modular reactor (SMR), specifically the lead-cooled fast reactor (LFR), coupled with molten salt thermal energy storage (MSTES) in its balance-of-plant (BOP). The detailed plant configurations we analyze are reported in [[10]](#D52_25).

This work answers the following research questions:

* Which configurations should be analyzed?
* How can a ‘differential’ economic analysis be performed without considering costs common to all scenarios?
* Can the MSTES additional investment be recovered with the additional revenues it generates?

1. LITERATURE REVIEW
   1. **Energy storage technologies and MSTES**

Energy storage usually consists of 3 steps: (1) withdrawing power from a plant or the grid, (2) converting it into a storable form, and (3) converting it back and returning it to the grid [[6]](#akinyele2014_6). There exist different types of energy storage [[5](#Coleman2017_5), [6]](#akinyele2014_6): mechanical (e.g., pumped hydro systems, compressed air storage), chemical (e.g., fuel cells, batteries), electrical (e.g., capacitors), and thermal. We focus on the latter, specifically by molten salt, considering two identical tanks as in [[10]](#D52_25). This technology has been developed and used since the 1980s because of concentrating solar power plants needs [[7]](#Prieto2024_7_salts). We consider “solar salt" with a mass composition of 40% KNO3 and 60% NaNO3 [[7]](#Prieto2024_7_salts).

* 1. **Small modular reactors and LFR**

SMRs are nuclear reactors with an electrical output typically up to 300 MWe [[8]](#IAEA2023_8_smr). There are over 80 possible designs and concepts [[8]](#IAEA2023_8_smr), with most of Gen-IV technologies falling into this category. SMRs go against the typical economy-of-scale trend that lead to the common GW-sized NPPs. However, they may recover this economic deficit with simplified and inherently safe designs, better fuel use, improved factory construction, serial production, and long lifetimes [[9]](#Locatelli2014_9_smrEconomics). This work focuses on lead technology. Lead-cooled fast reactors (LFRs) are cooled either by pure lead or lead-bismuth eutectic, each with its positives and drawbacks [[12]](#ALFRED2020_12). A significant global effort has been put into developing this technology: a European demonstrator (ALFRED) is planned for the coming years [[10](#D52_25), [12]](#ALFRED2020_12). LFRs could be coupled with MSTES due to the compatibility between the operating temperature of the salts (400°C [[7]](#Prieto2024_7_salts)) and the secondary steam loop of the NPP (up to 450°C [[10](#D52_25), [12]](#ALFRED2020_12)).

1. METHODOLOGY
   1. **Hypothesis and plant configurations**

The following are the main hypotheses considered in this work to simplify the economic analysis:

* 'Differential' analysis: we do not consider cost and revenues common to all configurations. We evaluate the increase in investment and revenues generated by the introduction of the MSTES into the BOP;
* Molten salt is loaded during the lowest electricity prices hours and unloaded during the highest prices ones, even if they are not consecutive, as shown in Fig. [1](#FIG_priceITA). Salts cannot be loaded and unloaded at the same time;
* We express all costs and prices in 2022 USD (or '$’). We retrieved all inflation coefficients and exchange rates from [[13]](#calcoloinflazione_13).

Other assumptions are introduced, if necessary, in the steps’ descriptions. This work considers the ALFRED reactor, with a nominal electrical output of 118 MWe [[10](#D52_25), [12]](#ALFRED2020_12). For the MSTES, we consider 3 possible tank sizes (S1, S2, and S3), 3 unloading schemes (U1, U2, and U3; each one coupled with a turbine of different size), and 2 loading schemes (L1 and L2). The designs, sizes, pressures, temperatures, mass, and energy balances of the configurations are described in [[10]](#D52_25). We report some details in Tab. [1](#TAB_configurationcharateristics). The times necessary to fill or empty the tanks are also present in [[10]](#D52_25): loading times go from 3 to over 19 hours; unloading ones from 2 to over 28 hours.

TABLE 1. MAIN CHARACTERISTICS OF THE ANALYZED CONFIGURATIONS

|  |  |  |
| --- | --- | --- |
| **Reactor** | LFR | ALFRED: 300 MWt, 118 MWe. |
| **Loading and**  **Unloading Schemes** | U1L1 | Plant net power when loading and unloading: 80.6 and 136.0 MWe. Unloading/loading time ratio: 1.44. |
| U1L2 | Plant net power when loading and unloading: 41.5 and 136.0 MWe. Unloading/loading time ratio: 2.87. |
| U2L1 | Plant net power when loading and unloading: 73.6 and 153.6 MWe. Unloading/loading time ratio: 0.72. |
| U2L2 | Plant net power when loading and unloading: 35.0 and 153.6 MWe. Unloading/loading time ratio: 1.43. |
| U3L1 | Plant net power when loading and unloading: 68.3 and 187.1 MWe. Unloading/loading time ratio: 0.36. |
| U3L2 | Plant net power when loading and unloading: 30.1 and 187.1 MWe. Unloading/loading time ratio: 0.72. |
| **Tanks** | S1 | Total salt: 12000 ton. Diameter: 24.2 m. Height: 14 m. |
| S2 | Total salt: 15000 ton. Diameter: 27.1 m. Height: 14 m. |
| S3 | Total salt: 20000 ton. Diameter: 31.3 m. Height: 14 m. |

* 1. **Codes of accounts**

To be sure to consider all the costs of the plant, we developed a list, or code of accounts, for both the LFR and the MSTES following [[14]](#GIFguidelines2007_14). For the MSTES, the accounts include direct costs (civil structures and improvements, MSTES equipment, loading and unloading systems, electrical, and miscellaneous equipment), indirect and owner’s costs, decommissioning, and operation and maintenance costs (O&M, both fixed and variable). Regarding the LFR, given the differential nature of the study, we are only interested in the turbine generator equipment and the O&M costs. All other costs do not change from one configuration to another, thus, we do not consider them. Additionally, regarding these LFR accounts, we are not interested in their absolute costs but rather in the increase from the base one due to the MSTES inclusion in the BOP.

* 1. **Cost estimation**

In the following sections, we provide a more detailed description of the cost estimation for each relevant account. It is important to mention that, where applicable, we considered the economy-of-scale principle following [[21]](#Phung1987_21) and calculated the inflation coefficient [[13]](#calcoloinflazione_13). We considered the plant as a First-Of-A-Kind (FOAK) and we adjusted affected accounts by a fraction corresponding to the ratio of values reported in [[15]](#Holcomb2011_15) for large NPPs.

* + 1. *Direct costs of MSTES*

The account 'civil structures and improvements' includes yardwork, buildings, and other civil works: we consider it a fraction of the total direct cost (DC), fixed at 0.25 and retrieved from [[15]](#Holcomb2011_15). Both loading and unloading systems comprehend a salt pump [[10]](#D52_25): their costs are evaluated following [[18]](#KellyKerney2006_18), which provided equipment cost, site labor, and material costs. For the heat transfer systems, we evaluate the factory cost of the main components (heat exchangers and pumps [[10]](#D52_25)) using the models from [[16]](#Shamoushaki2021_16): we introduced factors regarding materials, maximum temperature, and maximum pressure [[20]](#smith2005_20), and we evaluated additional site labor and material costs using the same proportion of [[15]](#Holcomb2011_15). The amount of salt depends on the tank size [[10]](#D52_25), Tab. [1](#TAB_configurationcharateristics). The total cost is escalated from 0.8 $/kg (2009 $) which includes also transportation, labor, and first melting [[19]](#Ding2021_19). We evaluate tank costs following the procedure in [[18]](#KellyKerney2006_18): the bulk cost is the material, considered carbon steel and able to sustain salt temperatures of 400°C [[7]](#Prieto2024_7_salts), sufficient for this application [[10]](#D52_25). Tank foundation and insulation costs are considered equal to 75% of the cost of the tanks [[18]](#KellyKerney2006_18). For other miscellaneous equipment, we use the same procedure of the account 'civil structures and improvements', considering it 0.055 of DC [[15]](#Holcomb2011_15).

* + 1. *Other MSTES costs*

We estimate the total indirect costs as fractions of the DC [[17]](#Thaker2017_17): contractor's cost at 12%, owner's cost at 5.6%, and fees and insurance at 8%. The sum of the DC and the total indirect costs is the total capital investment (TCI). We evaluate both variable and fixed annual O&M costs at 2% of the TCI [[17]](#Thaker2017_17). For simplicity, decommissioning costs are considered equal to 10% of the TCI.

* + 1. *Nuclear plant costs*

For the LFR, our focus is solely on the increase in costs from including the MSTES in the BOP. The main components are the turbine generator and its equipment. We followed the methods of [[22]](#Ganda2018_22) based on [[15]](#Holcomb2011_15) data. Regarding the feed heating systems, the main components (heat exchangers, pumps, and air-cooled condenser [[10]](#D52_25)) are evaluated again from [[16]](#Shamoushaki2021_16) and [[20]](#smith2005_20), as above. Additionally, we assume that the differences in O&M costs for the LFR are negligible among the different configurations.

* 1. **Revenues estimation**

We retrieved the electricity prices from [[23]](#entsoe_23). We selected the hourly data for the year 2023 for Romania (as the host country for ALFRED [[12]](#ALFRED2020_12)), Germany, and Italy due to their significantly different electricity price variations throughout the year [[23]](#entsoe_23). We decided to choose one of the following approaches:

* 1-day approximation: the n-th hour of the ‘average’ day is the average of the 365 n-th hours of the year;
* 2-day approximation: as above, but performed for ‘winter’ (from 21st September to 20th March) and ‘summer’ (from 21st March to 20th September) to see the differences between hot and cold seasons;
* 5&2 approximation: as above, but the year is divided into ‘weekdays’ (from Monday to Friday) and ‘weekend’ (Saturday and Sunday).

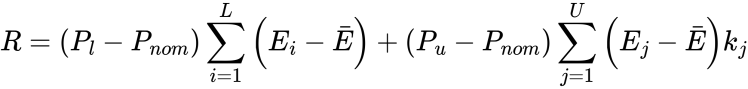
Given the similarities of the different curves (all ‘duck’ shapes, Fig. [1](#FIG_priceITA)), we selected the 1-day approximation.

Unloading hours

Loading hours

*FIG**. 1. The different approximations applied to the data from Italy 2023*

At this point, from annual, the analysis becomes daily, and we can introduce another important assumption: during the average day, the total amount of loaded salt is equal to the total amount unloaded. Now, given the loading/unloading time ratios from [[10]](#D52_25) and a certain loading period, we can compute the unloading hours required by this assumption. To simplify, we opted to compute only the theoretical maximum increase in daily revenues in each configuration (integer hours). The revenues, *R*, are the sum of the opportunity cost to load the salt (electricity not sold to the grid but used by the BOP) and the amount generated by the increased production at higher prices. *Pnom*, *Pl*, and *Pu* are the nominal power of the reactor, and the ones during loading and unloading, Tab. [1](#TAB_configurationcharateristics). *L* is the loading period in hours, and *U* the unloading one, determined from the ratio in Tab. [1](#TAB_configurationcharateristics). *E* is the electricity price in a specific hour of the average day, while *Ē* is the annual average. *k* is always equal to 1 except in the last unloading hour when it represents the fraction to be considered (e.g. if the unloading period is 2.4 hours, *U=3*, *k1=k2=1*, *k3=0.4*).



As a lower limit, daily increase in revenues must exceed daily O&M costs. They are also upper limited: either loading and unloading hours cannot exceed the period below or above the average price, or the tanks cannot be filled or emptied. Moreover, if two configurations have the same maximum revenues, the more expensive is discarded. Note that the revenues do not depend on the average electricity price but rather its deviations.

* 1. **Discounted cash flow**

We performe the discounted cash flow analysis (DCF) following [[11]](#CBA_24) to obtain the net present values (NPVs) of the configurations. We consider a MSTES lifetime of 30 years [[7](#Prieto2024_7_salts), [17]](#Thaker2017_17): the first two comprehend the plant construction, and the last its decommissioning. For the computations, we consider an interest rate of 0.05 [[15]](#Holcomb2011_15). The initial investment is equally divided between the construction years. From year 3 to year 29, the outflows are the O&M costs, while inflows are the maximum revenue multiplied by a load factor of 90%.

1. RESULTS AND DISCUSSION
   1. **Results from the cost estimation**

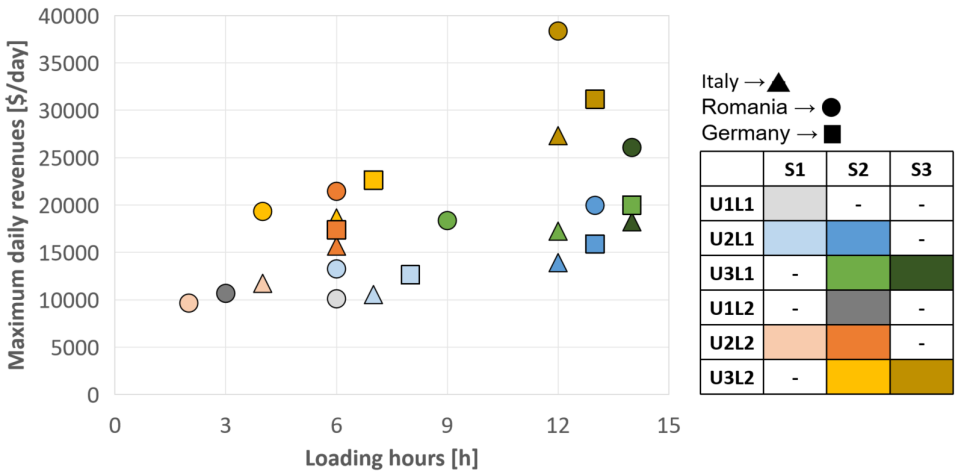
Tab. [2](#TAB_costestimation) reports the results of the cost estimations. Considering the 18 configurations and the 3 countries we analyzed, 54 combinations are possible. The majority are excluded in the next steps.

* 1. **Results from the revenue estimation**

We compute the maximum revenues for all scenarios. In case they are smaller than the O&M costs, the configuration is excluded. By this reasoning, U1 configurations are never profitable for Italy and Germany (for which we exclude also U2L2S1). For Romania, this applies to U1L1S3, U1L2S1, and U1L2S3. For the same reason, U3S1 configurations are excluded. Moreover, we avoid considering configurations with equal maximum revenues to cheaper ones. This is seen for U2S3 configurations. For Germany, we exclude also U3L1S3, while for Romania, U1L1S2. At this point, only 24 configurations may be worth analyzing further (8 for Italy, 10 for Romania, and 6 for Germany). We report the maximum revenues in Fig. [2](#FIG_revenuesMAX).

TABLE 2. COST ESTIMATION FOR ALL THE CONFIGURATIONS, VALUES IN MILLION $

|  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| [M$] | **MSTES** | | | | **NPP** |  | **MSTES** | | | | **NPP** |
| *DC* | *Indirect costs* | TCI | Annual O&M costs | Increase in NPP costs | *DC* | *Indirect costs* | TCI | Annual O&M costs | Increase in NPP costs |
| **U1L1S1** | *61* | *16* | 76 | 3 | 9 | **U2L2S1** | *69* | *18* | 87 | 3 | 17 |
| **U1L1S2** | *68* | *17* | 85 | 3 | 9 | **U2L2S2** | *77* | *20* | 97 | 4 | 17 |
| **U1L1S3** | *85* | *22* | 106 | 4 | 9 | **U2L2S3** | *87* | *22* | 109 | 4 | 17 |
| **U1L2S1** | *67* | *17* | 84 | 3 | 9 | **U3L1S1** | *75* | *19* | 94 | 4 | 32 |
| **U1L2S2** | *74* | *19* | 92 | 4 | 9 | **U3L1S2** | *80* | *21* | 101 | 4 | 32 |
| **U1L2S3** | *91* | *23* | 114 | 5 | 9 | **U3L1S3** | *91* | *23* | 115 | 5 | 32 |
| **U2L1S1** | *63* | *16* | 79 | 3 | 17 | **U3L2S1** | *81* | *21* | 101 | 4 | 32 |
| **U2L1S2** | *71* | *18* | 89 | 4 | 17 | **U3L2S2** | *87* | *22* | 109 | 4 | 32 |
| **U2L1S3** | *81* | *21* | 102 | 4 | 17 | **U3L2S3** | *98* | *25* | 122 | 5 | 32 |



*F**IG. 2. Maximum daily revenues of the analyzed configurations*

* 1. **Results from the DCF and comments**

We report the results of the DCF calculations for the remaining 24 configurations in Tab. [3](#TAB_NPV).

TABLE 3. NPV OF THE 24 REMAINING CONFIGURATIONS, VALUES IN MILLION $

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **NPV**  **[M$]** | **Italy** | | | **Germany** | | | **Romania** | | |
| **S1** | **S2** | **S3** | **S1** | **S2** | **S3** | **S1** | **S2** | **S3** |
| **U1L1** |  |  |  |  |  |  | -82 |  |  |
| **U2L1** | -92 | -92 |  | -83 | -83 |  | -80 | -65 |  |
| **U3L1** |  | -110 | -127 |  | -97 |  |  | -105 | -91 |
| **U1L2** |  |  |  |  |  |  |  | -105 |  |
| **U2L2** | -99 | -96 |  |  | -89 |  | -108 | -70 |  |
| **U3L2** |  | -116 | -97 |  | -97 | -80 |  | -112 | -47 |

We can see that price arbitrage is never sufficient to cover the additional investment for the MSTES: electricity price differences or 'ranges', i.e., the differences between the highest price and the lowest one of the day, are not large enough. For Germany and Romania, the optimal configuration is U3L2S3, profitable with a 60% and 30% increase in revenues, respectively. For Italy, U2L1 configurations might seem best, but they require a 150-200% revenue increase to be profitable. This value for U3L2S3 is 80%, making it the preferable choice also in this case.

This analysis assumes this plant is a FOAK, meaning TCI may be lower for subsequent similar plants. We also assumed the NPP bids only in the day-ahead market. Bidding also in the intraday market could optimize revenues: due to fluctuations of demand and offer, the ability to correct the inaccuracies of the day-ahead market can be very profitable. Our computations of the maximum daily revenues are also conservative: by averaging all the days the largest ranges are lost, and, given that peaks and valleys may happen at different hours, the average peak is smoother and broader. We can deepen this argument by showing that the total possible revenues, or equivalently the area above or below the average electricity price, are proportional to the ranges of the days, Fig. [3](#FIG_proportionality). Thus, we report the minimum ranges needed to achieve positive NPVs for the different configurations in Fig. [4](#FIG_rangeneeded). This confirms the most expensive configuration, U3L2S3, is the preferable one, with a daily threshold range of around 100 $/MWh. In Tab. [4](#TAB_randomDays), we report the revenues computed in 4 random 2023 days, comparing them with the result shown in Fig. [2](#FIG_revenuesMAX) regarding U3L2S3. In the same table, we also report the range of the specific days, supporting the results in Fig [4](#FIG_rangeneeded). Moreover, future power systems will likely experience a much larger price volatility due to the increase in renewable penetration: we could expect large ranges to be much more common. This will increase the economic value of MSTES and storage technologies because these options are most beneficial in such markets. We must acknowledge that the reported analysis of three countries is not enough to show a balanced evaluation of such technologies which will likely be implemented in scenarios with more volatile electricity prices.

*FIG. 3. Proportionality between the total area above (or below) the average price and the range of each day of 2023*

*F**IG. 4. Range at which the NPVs of the configurations become positive*

TABLE 4. INCREASE IN DAILY REVENUES AND RANGES COMPUTED FOR EXAMPLE DAYS

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| ***Configuration U3L2S3*** | | **23rd January** | **8th April** | **10th August** | **17th October** |
| **Germany** | *[k$/day]* | 57 | 22 | 54 | 38 |
| *Range* | 124 | 46 | 167 | 94 |
| **Italy** | *[k$/day]* | 44 | 32 | 20 | 25 |
| *Range* | 105 | 119 | 61 | 62 |
| **Romania** | *[k$/day]* | 105 | 26 | 26 | 80 |
| *Range* | 235 | 70 | 94 | 200 |

The increase in TCI due to the MSTES does not significantly impact the NPP profitability, as MSTES costs are a small fraction of the total NPP one. However, MSTES can be very profitable for large ranges, especially if the electricity price is negative, common for countries with high renewable penetration, while simplifying reactor operation. We could improve this work by considering more than one year and less stringent approximations, thus, better capturing the value of thermal storage.

1. CONCLUSION

We conducted an economic analysis on energy storage integrated into a SMR BOP, focusing on molten salt energy storage (MSTES) and lead-cooled reactors (LFR). We examined 18 MSTES-LFR configurations, analyzed in 3 countries: Italy, Romania, and Germany. By performing an 'average' day analysis with 2023 electricity prices, we estimated capital costs, revenues, and NPVs for the different scenarios. In all cases, price arbitrage alone is insufficient to recover the additional investment for the MSTES. The most promising configuration is U3L2S3, despite being the most expensive, requiring a daily electricity price variation of around 100 $/MWh to be profitable. We expect larger price variations for future power systems with increased renewable penetration.

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