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Supercritical CO2-Based Heat Pump Cycle for Electrical Energy Storage for Utility Scale Dispatchable Renewable Energy Power Plants

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ABSTRACT

Thermal energy storage via molten salt is well established in the heat treatment and concentrated solar power industry. It is very cost competitive especially for large scale plants against electrochemical battery solutions. For energy sources that directly produce electricity (as opposed to thermal energy in the case of solar thermal), like solar photovoltaic and wind power plants, it is necessary to convert electricity to heat in order to utilize the storage in molten salt. A heat pump system based on supercritical CO2 cycle for high temperature has been proposed as a charging system to heat molten salt. Discharge occurs through a standard water steam cycle. Cost and competitiveness analysis shows, that although round trip efficiency is limited due to the use of off-the-shelf commercially available components, the overall low cost of the solution enables a very competitive levelised cost of electricity against competing established electrochemical battery technology when co-located with a PV plant with an 8 hour after sunset full load discharge capability.

MOTIVATION

It is recognized that energy storage, specifically large scale (hundreds of MW and multi-hour (6+ hrs)) storage is key to large scale renewable energy integration, whether PV or wind. With increasing variable renewable energy penetration as shown in Figure 1, extracted from [1], large scale electricity storage is almost a requirement. Energy storage allows better utilization of renewable energy assets, while improving dispatch and load balancing on the network. All this leads to lower overall costs for the economy when switching to renewable energy by reducing curtailments and deferring large investments in grid transmission systems. This is borne out by multiple studies. An example is shown in Figure 2 excerpted from an internal study [2]. This figure shows that for the same amount of renewable energy share the overall system cost (as defined by the costs of additional power generation capacity to meet the renewable energy target) is higher compared to that if some investment was also made in adequate amount of storage instead. Large current electricity storage technologies are primarily oriented towards Pumped Hydro Storage (PHS) and increasingly small scale electrochemical battery solutions and also emerging technologies like compressed air energy storage (CAES). However PHS and CAES, both of which are large scale storage technologies, have very strong geographical constraints in the form of mountainous areas for the former and large hermetic salt caverns for the latter. As PV and wind farms are deployed in an ever wider variety of geographies, their accompanying storage technology needs to be free from geographic constraints.

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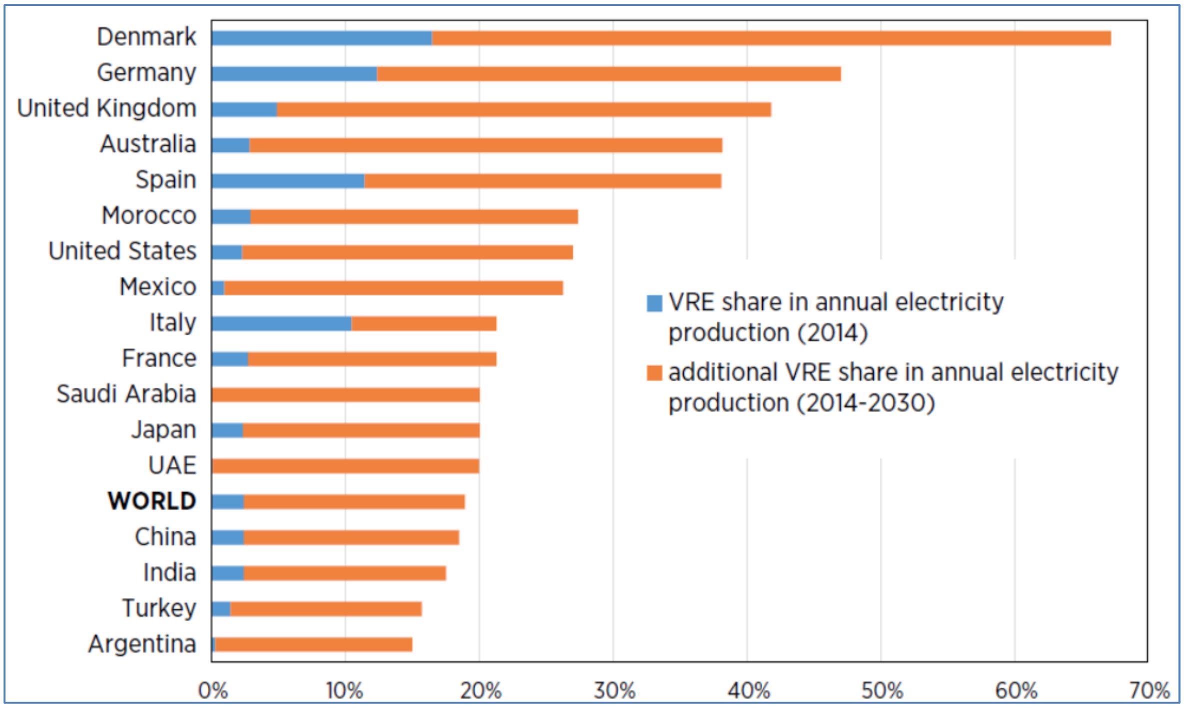


FIGURE 1: VRE-Variable renewable energy i.e. solar and wind energy is shown as a percentage of overall mix for various countries

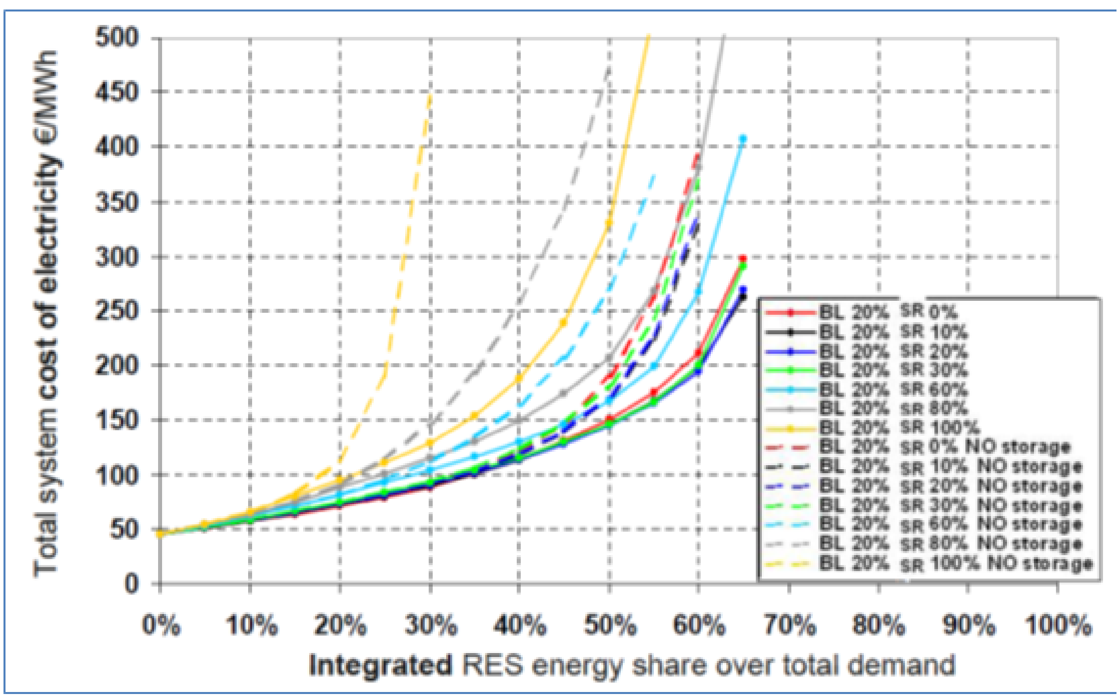


FIGURE 2: Total system cost of electricity vs integrated Renewable Energy Source (RES) share for different energy mixes. SR = Solar/(Solar + Wind) in terms of installed capacity with and without energy storage. Base Load (BL) installed capacity is 20% of peak demand which can't be readily switched off. Dotted lines represent increasing renewable energy with 'No STORAGE' whereas the solid lines represent integration of the same amount of renewables with adequate large scale storage. Grid demand data corresponding to Tennet grid operator from Germany is used.

In the last decade, the only large scale, cost effective and geographically-independent energy storage technology that has emerged and is commercially deployed at scale is molten salt thermal energy storage. Molten salt is basically a mixture of nitrate salts 60%-40% $NaNO_3$ - KNO_3 which has been used in the heat treatment industry for many decades. Since the 90s when its use as an energy storage medium was demonstrated at a large scale at the Solar Two molten salt pilot plant by Sandia National Laboratories (U.S.), [3] it has been used commercially in various concentrated solar plants in Spain and California as well as under deployment in large projects in North and South Africa.

(a) 8 hours of storage for a 50 MW CSP plant using molten salt operating in Andasol 3, Spain

(b) 10-12 hours of molten salt storage for a 100 MW solar plant at Crescent Dunes, CA, USA

FIGURE 3: Molten salt thermal energy storage references. Typical amount of salt stored in the tanks is 30-50 thousand tonnes.

The main advantage of molten salt for solar thermal plants, is that, the primary heat source can be directly stored in large tanks at atmospheric pressure. It is evident that, where the primary energy source is already in the form of electricity, as from PV or Wind, a storage system based on thermal energy will be inherently less efficient than an electrochemical battery. However, energy storage is ultimately made viable not uniquely by its round-trip efficiency, but by the overall economics of the given application. A high efficiency energy storage is not very attractive if its cost is too high and neither is a cheap storage of much interest if the efficiency is too low, as charging the system requires large amounts of electricity to get relatively little out during discharge. The decisive point is to achieve the right balance of cost, scalability and efficiency that is not only competitive in a given electricity pricing regime but can sustainably reduce costs with increasing deployment, thereby proving applicability beyond a niche market. Thus, the most suitable technology for a specific project shall be determined by an aggregated thermo-economic indicator, taking into account technology (i.e. efficiency), initial investment, operation and maintenance costs, as well as financial and market boundary conditions. A financial model will typically be used to compute such figures of merit, as levelized cost of electricity or net present value of the project.

In summary, an energy storage product is presented in this paper which could meet the following needs

1. DISPATCHABLE POWER: The power provided would be dispatchable and comparable to that of Combined-Cycle gas turbine or industrial steam turbine plant with generation characteristics easily integrated and understood by grid operators

2. ECONOMY OF SCALE: The larger the plant the cheaper should be the unit cost to enable large scale renewables. Thermal cycles are particularly well suited to this, as these could be made more efficient with increasing size but also their specific costs would reduce. This is contrasted against most modular electrochemical storages where power and energy are linked leading to linearly increasing system costs with power or energy rating.
3. PROVEN EQUIPMENT BASIS: The equipment should be based on proven thermal technologies that are in widespread use. The use of components from the industrial processes and oil & gas industries integrated with proven commercial equipment from the concentrated solar power industry reduces investor risk.
4. LOW MARGINAL COST OF STORAGE: Increasing an hour of storage simply means having some more tonnes of molten salt in the tanks. At 25-35 USD/kWhe the marginal cost of molten salt storage is very low compared to batteries (which is 700-1000 USD/kWh with regular replacements including power conversion systems). Although more tanks might be needed beyond a certain size limited by large tank manufacturing, creating step changes in overall cost, the overall trend for a large energy range is still reducing fairly linearly as a function of specific energy costs.
5. MINIMAL SYSTEM AGEING: No active component replacement, or ageing of storage materials, during the plant design lifetime (approximately 25 years) unlike that expected with Li-ion battery of 7-10 years which thus requires a full replacement approximately half way through the commercial life of the project. Small amounts of degradation of molten nitrate salt to nitrites or thermal decomposition is considered to reduce less than 2% of total mass over the 25 year lifetime.
6. LOW ENVIRONMENTAL IMPACT THROUGH THE LIFE CYCLE: No generation of environmentally unsound waste due to replacement of components (e.g with Li-ion batteries storage system). No toxic materials or Environmental, Health & Safety dangers due to catastrophic failure.
7. GEOGRAPHICALLY INDEPENDENT: Other large scale storage technologies such as pumped hydro, require specific geographic features like hills or lakes for its implementation while Compressed Air Energy Storage (CAES) require air-tight caverns.

CONCEPT DESCRIPTION

The Advanced Molten Salt Electrical Storage System or AMSES consists of a heat pump that absorbs heat from a low temperature source and uses electricity to increase the temperature to a higher level and transfer the heat to the storage medium, the molten salt. The working fluid of choice for the heat pump is carbon dioxide. CO_2 recuperated cycles are well studied [4] and especially for storage applications through heat pumps [5; 6] and are known to have good potential, in terms of cost, availability of equipment, hazardous materials and thermodynamic properties

The basic schematic of the system is shown in Figure 4. This system makes use of carbon dioxide compressors from industrial, oil and gas applications, whose upper temperature limit is at about 480°C. Higher temperature compressors at 30-50 MWe capacity are not available on the market. Molten salt, on the other hand, can be used to store heat up to a temperature of about 565°C, thereby allowing steam generation at 550°C and thus achieving the best possible efficiency from the water steam cycle. An electric heater downstream of the heat pump can assist to boost the molten salt temperature to the target storage temperature. The current temperature limitation of the heat pump cycle is not primarily due to technological limitations in materials, sealings or others, as high temperature process conditions are common in gas turbine technology. The limitation has uniquely to do with the fact that the market has so far never required a CO2 compressor working without intercooling and suppliers see no reason to develop a high temperature compressor without a market application hence the need for further development in this area.

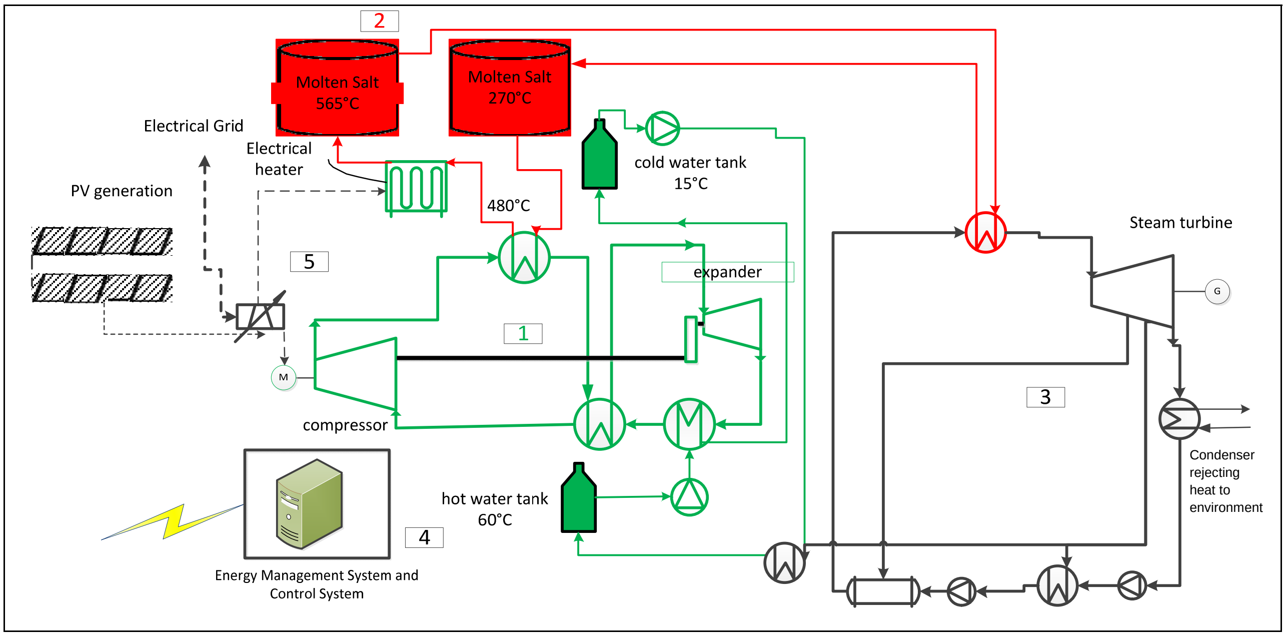


FIGURE 4: Schematic showing the integration of heat Pump cycle with a standard water steam cycle

In Figure 4, during the charging cycle, the compressor is operated with electricity and produces hot CO_2 that transfers heat to molten salt via a molten salt heat exchanger at 480°C. This molten salt is further heated up to its maximum temperature of 565°C with electric heaters. The cold CO_2 is then expanded through a turbo-expander to recover some of the energy and the cold stream takes in heat from a hot water tank at 60°C. The resultant cold water is stored in a separate cold water tank. Recuperating the CO_2 allows to maintain molten salt above 240°C in the molten-salt CO_2 heat exchanger below which the salt would freeze. During the discharge cycle, as the steam turbine is now turned on, a suitable pre-heating extraction from the steam turbine is sent to another heat exchanger to heat the stored cold water which is stored in the warm water tank thereby refreshing it for the next charging cycle. In this way the cycle is self-contained in the absence of any external heat source, but an external heat source, from waste heat recovery or any other source can be easily integrated and it would simply increase the round trip efficiency of the whole system. Detailed descriptions and integration concepts are further described in patent applications, [7; 8]. Although, in normal operations, at the end of a 24 hour period, the low temperature molten salt tank and the hot water tanks should both be full for the next day of charging, it is possible that partial discharge occurs due to lack of sunshine on one day, thereby creating a shortage for discharge the next day. Currently this problem is avoided by a highly oversized primary energy generator (PV field) which also tends to be the economic option due to low PV costs. However, other types of parasitic consumptions would be needed if the tanks are not refilled back to their original position.

The cycle parameters for the heat pump technology are arrived at, by trying to maximize the coefficient of performance (COP = Heat transferred to the molten salt/ electricity absorbed by the motor driving the compressor) while also balancing the lower discharge efficiency due to enthalpy extraction from the water steam cycle. The heat pump T-s diagram is shown in Figure 5 (a).

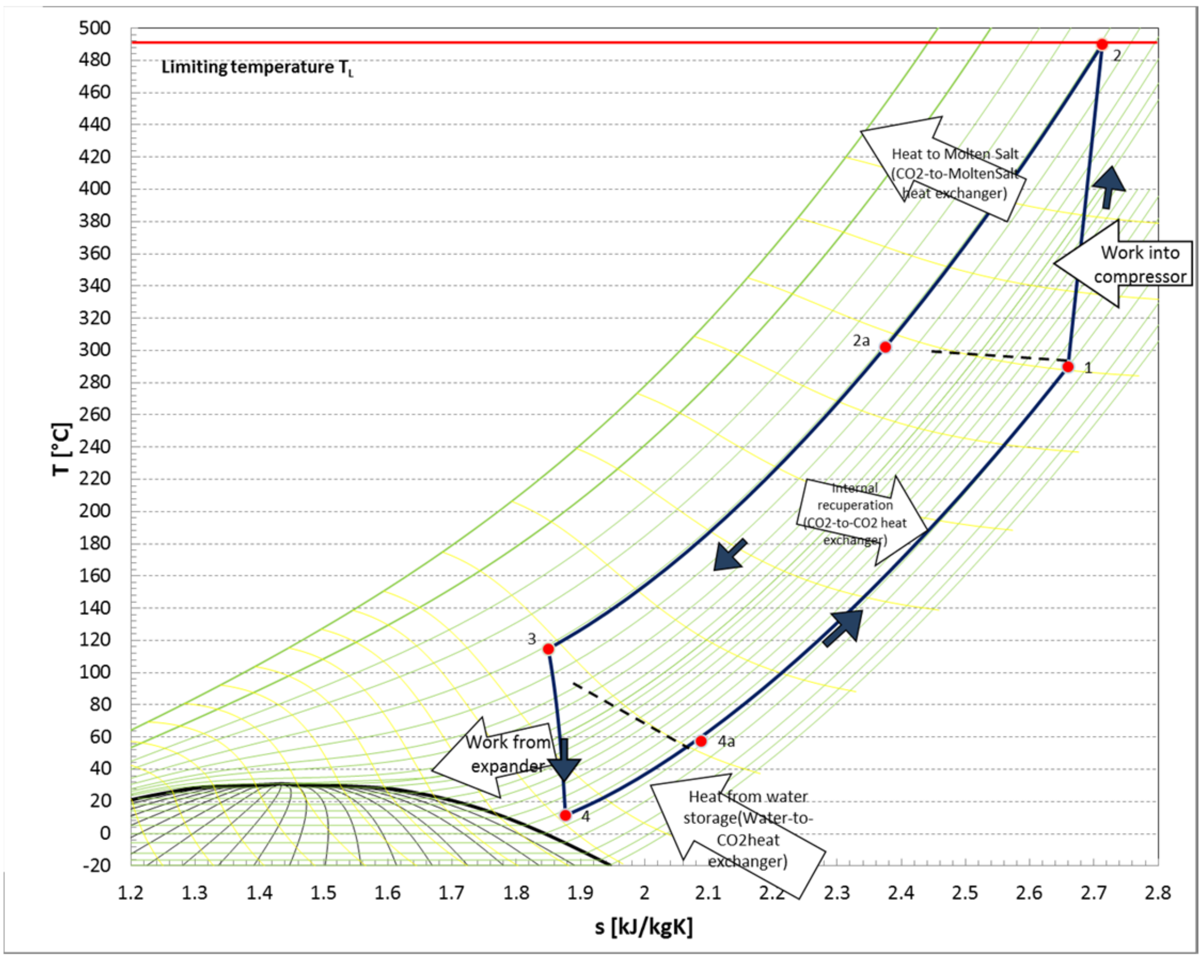


FIGURE 5: Representative T-s diagram of the heat pump cycle using supercritical CO_2 for charging. During discharge a standard Rankine steam cycle is used.

The T-s diagram is constrained by the following constraints from the state-of the art technology, supply chain, cost optimization and availability of components 'off-the-shelf'.

1. CO2 compressors from the oil and gas and process industry do not typically achieve high temperatures >400°C and high pressure >140 bar simultaneously due to lack of applications.
2. Low temperature source (point 4a in Figure 5) should be as high as possible to boost COP of the heat pump

3. Low temperature source should not rely on an 'external heat source' but be stored and refreshed from the steam turbine cycle – reduction in Water-steam cycle efficiency (defined as Net electrical output/Total heat input at steam generator) could be tolerated as long as overall round trip efficiency is optimized.
4. Low temperature heat storage should use the cheapest fluid possible, i.e. water. This necessitates water temperature from being below 100°C in order not to use pressurized tanks which can have very significant costs.
5. As molten salt freezes at 240°C, the cold side of the molten salt in the heat exchanger should always be above 270°C in order to prevent this freezing.
6. The use of standard shell and tube exchangers is foreseen. Typical pinch points of about 5°C-10°C are allowed at the various heat exchangers.

PRODUCT DESCRIPTION

OVERALL LAYOUT

The specific application of the AMSeS system as a large scale storage system for very large scale photovoltaic plants is hereby presented. A typical schematic of its colocation with a photovoltaic plant is shown in Figure 6. It must be noted that the actual footprint (for a 100 MWe x 8hrs = 800 MWhe) occupies one third the amount of a land for a containerized Li-ion battery stack with power converters (i.e. AC-to-AC scope). Unlike a battery assembly however, such a system relies on traditional installation, erection and construction constraints.

FIGURE 6: SCHEMATIC SHOWING LAYOUT OF A 100 MW, 8 HOUR FULL LOAD EQUIVALENT HOURS OF STORAGE WITH A SUITABLY LARGE PV PLANT

The arrangement and sizes of the various heat pump components are shown in a close up view in Figure 7. As the largest size of the compressors available off-the-shelf is limited to close to 40 MWe, a large power rating can only be realized by parallelizing units. Multiple units are shown coupled to their own motor and arrangement. In spite of the modular arrangement of the heat pump turbo-units due to size restrictions, some specific cost reductions can be achieved when multiple units are installed. On the other hand, the cost advantage in a larger steam turbine and water steam cycle are very large compared to a small scale system.

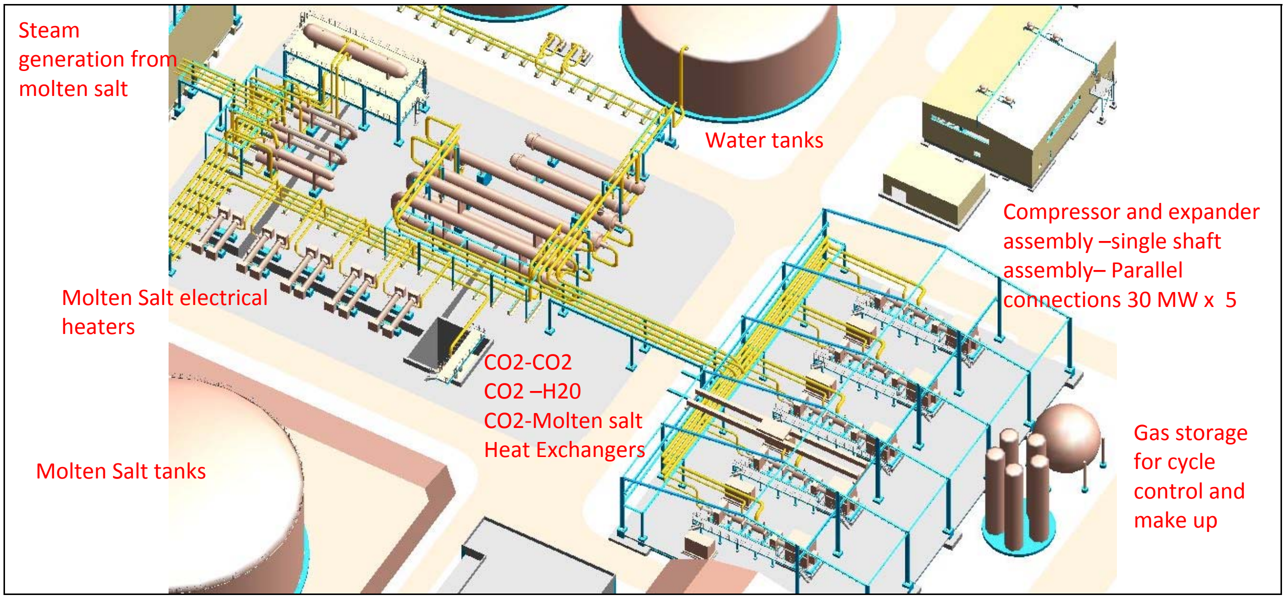


FIGURE 7: Schematic of a 100MW discharge AMSES plant with molten salt interfaces. Steam turbine generator is not shown

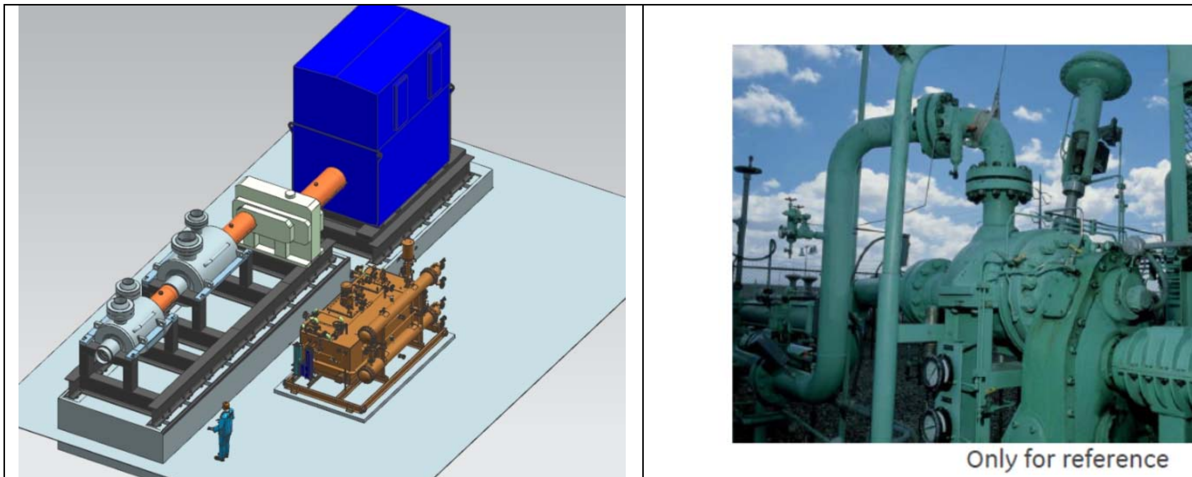
AUXILIARY EQUIPMENT

Important auxiliary equipment is also shown in Figure 7. CO_2 gas storage tanks for managing the load control are needed. During startup, shutdowns and ramp changes the gas storage helps to buffer the overall CO_2 mass inventory. A special control system and operating strategy have been designed to perfectly time daily startup and shutdown of the charging cycle coinciding with the sunrise and sunset, and to match its load to the variable power supplied by the PV field, thereby perfectly shaving its output and minimizing losses. Overnight holding and maintenance of close to cycle conditions in critical points in the loop are important considerations in the control and evacuation strategy. Additionally cryogenic storage tanks to make up CO_2 inventory for any losses, like that from sealing systems are also foreseen.

Molten salt tanks and steam generator systems are exactly the same as that required in concentrated solar power plants, while the use of shell-and-tube heat exchanger technology allows the use of standard, well-known and robust technology without incurring prohibitive equipment costs associated with niche CO_2 specific heat exchanger technology. Thus, the CO_2 recuperator, molten salt-CO_2 heat exchangers and CO_2-H20 heat exchangers are sized for the large scale and designed for 25 years lifetime at a techno-economic optimum.

COMPRESSOR AND EXPANDER

As mentioned the use of compressor technology, based on existing CO2 compressors used in the process and oil and gas industry is required. An arrangement diagram of the double casing double staged CO_2 compressor is shown in Figure 8(a) available from Howden CKD [9]. The CO_2 compressor is based on the same design family used extensively in the ammonia manufacture and process industry. The use of special high performance alloys helps to push the outlet temperature for this application. The expander which is connected to the same shaft via a gearbox operates in very standard operating regime and hence does not require special adaptation. A reference expander used extensively in the oil and gas industry manufactured by GE is shown in Figure 8(b).



(a) (b)

FIGURE 8: (A) Schematic of double staged barrel centrifugal compressor from Howden CKD connected to a large scale variable speed motor (in blue).(b) A reference picture of an existing expander meeting the requirements of the heat pump and direct single shaft integration with the compressor

PERFORMANCE

Ultimately there is a cost optimization required to select the best techno-economic tradeoffs between using a low temperature steam cycle dictated by the upper temperature of the CO2 compressor or an electric heater for topping off till the maximum high temperature. A nameplate RTE (Round trip efficiency) is defined as the product of COP (coefficient of performance) and the discharge water steam cycle efficiency. Based on gross numbers (i.e. without accounting for parasitic losses) the performance is given in Figure 9. The advantage of using the cycle till 465°C (i.e. HP only) and therefore not having a topping electric heater to boost the temperature of the molten salt till 565°C, is that the overall COP of the charging cycle is higher, as the entire duty is realized by an efficient heat pump. The higher COP more than compensates the lower efficiency of the discharging water/steam cycle, thereby resulting in an overall higher RTE. The downside, is that more salt mass is needed to store the same amount of enthalpy and more number of expensive heat pump components (compressor-expander) compared to a less efficient but cheaper electric heater as denoted by (HP+EH) in Figure 9.

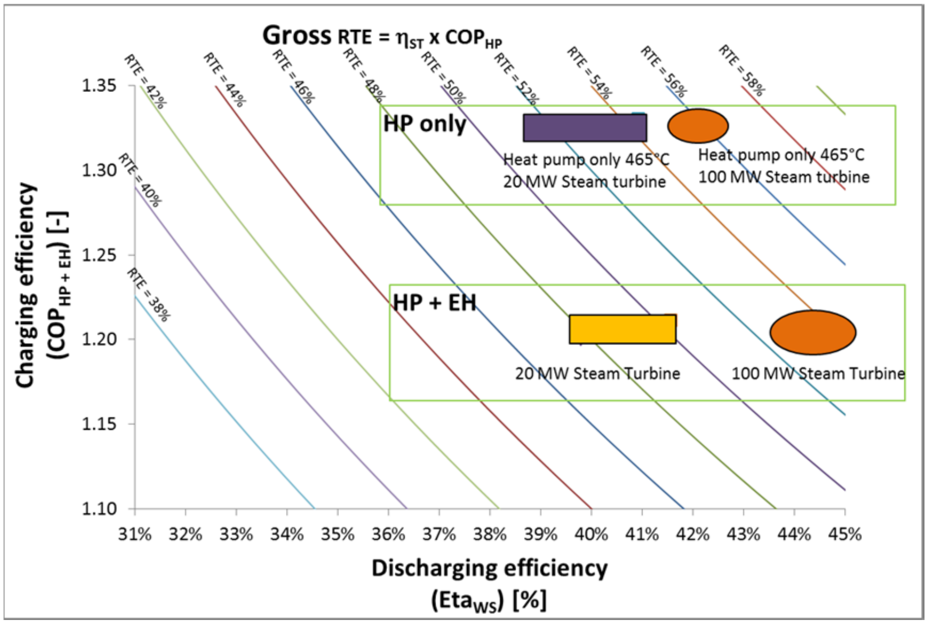


FIGURE 9: Gross round trip efficiencies for different configurations, both in terms of overall plant discharge capacity and upper temperature limit of heat pump. Typical gross round trip efficiencies of 50%-55% are possible: Legend HP = Heat Pump; HP+EH = Heat Pump + Electric Heater in series

The efficiencies shown in Figure 9 are shown as a range, since there could significant differences depending on the management of parasitic loads, the efficiencies of the steam turbines used or the water steam condensing technology selected. An important difference is that a large discharging cycle (at 100 MW) would have markedly higher efficiency compared to a smaller (20 MW) steam turbine, but no such advantage is visible for the heat pump since the 30-40 MWe limit is the largest for an industrial CO2 compressor available on the market.

COMPETITIVENESS

Considering the many, different types of energy storage applications, it is clear that any thermal cycle based solution would have lot of difficulty competing with electro-chemical batteries for sub-second fluctuations, UPS applications or short period grid support applications. The primary advantage for the present systems therefore, is specifically to support large scale renewable integration, by being co-located and thereby providing a duty profile from a PV or a wind plant, independent of the weather at a given time. This in fact meets a complementary need of the grid operators, customers and end users.

An ideal duty profile that is only possible with large scale storage is shown in Figure 10. In this, the storage system, charges the excess photovoltaic energy produced during the day time. If the nameplate output of the combined plant is set at 100 MW as shown in Figure 10, only when PV power is higher than the 100 MWe range, is the charging cycle switched on. After the sun sets and no more PV power is available, the charging cycle is switched off and the steam cycle is started drawing power from the hot molten salt which is heated and stored during the day. Until all the hot molten salt is used up, the cycle is discharged. In case of low sunshine days, the amount of discharge hours are reduced due to lesser energy collected; however, the presence of a large scale storage system allows meeting a given power in a predictable manner

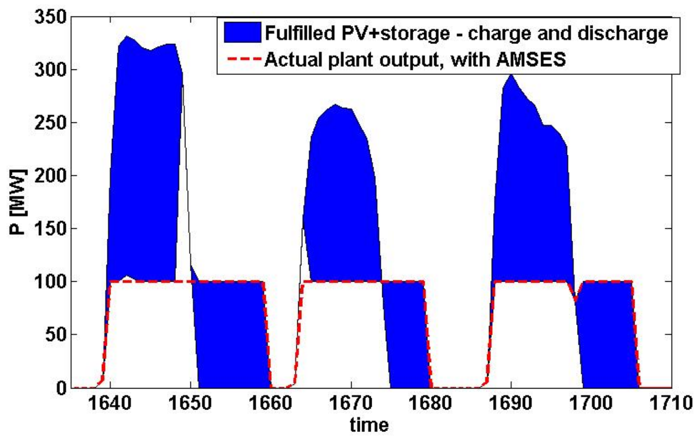


FIGURE 10: Duty profile for a flat output PV+storage plant. Oversizing of PV plant is needed to store enough energy to last for 8 hours after sunset

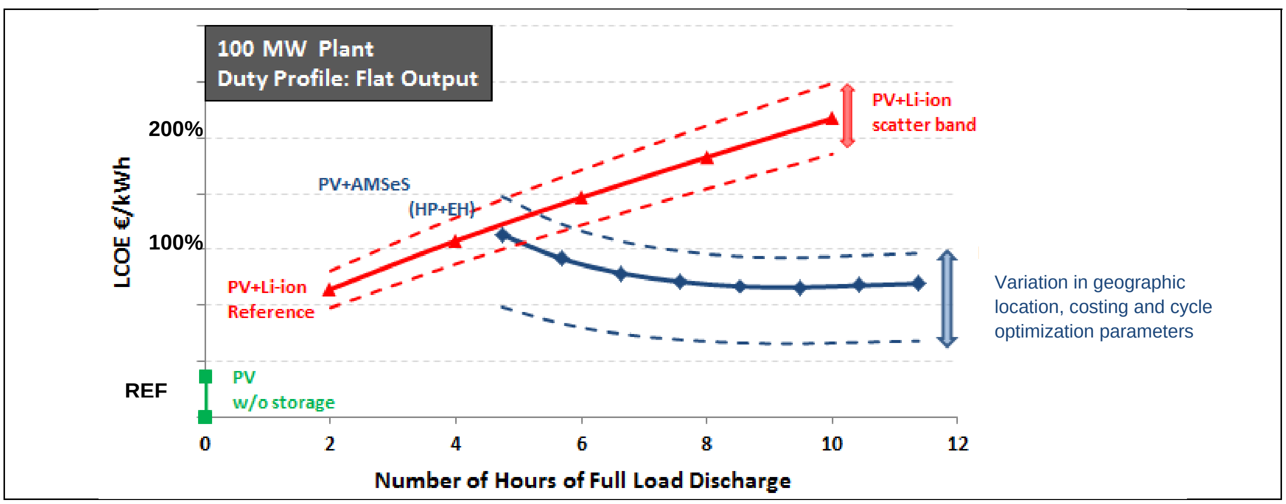


FIGURE 11: Increase in levelised cost of Electricity for a PV+storage plant compared to a PV plant with no storage at a reference 'sunny' location is shown, 25 years, 8% interest rate. Li-ion technology is based on $LiCoO_2$ industrialized large scale storage at 2016-2017 prices, with full power conversion and system cost included. Replacements to account for lifetime and aging are also considered according to industry standard guarantees.

The levelised cost of electricity is calculated for a PV plant suitably sized to produce enough energy to charge the system as well as dispatch power to the grid. The AMSES system consists of around 200 MW charging power and 100 MW discharging power with 8 hours of storage (i.e. around 40 ktons of molten salt). The number of hours of the storage is varied to check its influence on the levelised cost of electricity. The same exercise and energy calculations are performed with a similarly sized Li-ion large scale battery system with representative replacement rates and operating costs. The cost of additional photovoltaic modules to compensate for different round trip efficiencies is also taken into consideration. The results are shown in Figure 11.

It is seen that the levelised cost of electricity by adding storage increases the overall cost of the combined PV+storage plant as the CAPEX increases while overall energy produced reduced due to the electrical losses due to subsequent charge and discharge cycles (round trip efficiency). However, due to the economies of scale in lower specific cost at large scale, it is seen that the levelised cost of electricity by using the AMSES solution is significantly lower than that of a Li-ion solution for more than 5-6 hours of storage. Even though both of these are higher than that of a PV plant without any storage, it is a matter of scale, learning effects and increased cost reduction from scale that the costs in the future could drop enough to be competitive against PV without any storage. The reference solar resource shown in this figure is at a sunny place with about 1900 kWh/m2 in terms of annualized Global Horizontal Irradiance (GHI). The scatter bands shown in the graphs reflect the fact that as the location changes (i.e more solar resource) the cost of generation from PV would also change. The second important effect is the variation in cost of construction, installation etc depending on country of constructions as well as cycle optimization parameters. High labour cost countries or those with supply chain and accessibility issues would understandably have a higher cost for constructing the same plant. As Li-ion battery construction costs are not that significant as most of the technology is pre-packaged in China/South Korea and only assembled on site, local factors play a less important role thereby reducing the scatter band. In many developing countries viz. South Africa, India, Morocco etc., where renewable energy policies are incentivized directly by governments, having high local content is often valued much more by stakeholders than having technology and equipment imports from outside the country. In this way the construction and localization potential in the value chain of AMSES may even be an advantage in some countries.

OUTLOOK FOR IMPROVEMENTS

The current solution described in this paper is based on commercially available equipment, control systems, technologies and availability. The goal was to use primarily 'off-the-shelf' components. While the cost of electricity is already competitive against battery systems in large scale storage, a large potential for cost reduction and performance improvement exists. Many further performance improvements are possible through dedicated component improvements and better coordination with equipment suppliers. Furthermore, turbo-machinery improvement projects in the supercritical CO2 community could strongly benefit this current concept as well. Some specific areas for ongoing development are discussed below.

1. Daily start-up and shutdown of existing CO_2 compressors increase the operational and maintenance costs. Better understanding of material limitations and estimation of aging factors will push the envelope of current industrial CO_2 compressors.
2. Parasitic loads to keep the various cooling and lubrication systems running would be reduced.

3. Minimum load requirements of the compressor operation would be improved to ensure efficient operation for.
4. Compressors are normally designed to produce high pressure ratios, with the least amount of temperature rise for typical compression and Brayton cycle applications. Compressor designs that allow high temperature rise for a given pressure rise are ideal for heat pump applications thus hinting at new design paradigms.
5. Control systems to run the various operational modes can be improved for example, by testing with demonstrator units as industrial equipment is now being used in a different way.
6. Scale up of CO_2 compressors to 100 MW class would lead to very significant reductions in cost similar to other large scale turbomachinery.
7. Engineering feasibility studies for integrating CO_2 heat pump with a supercritical CO_2 turbine cycle for discharging, operating at inlet temperatures of >560°C should be investigated as a promising application for sCO_2 cycles application. This is a good application for some other sCO2 turbine development programs ([10; 11])
8. Integration with heating and cooling circuits and thermal hybridization are very attractive add-on applications that further differentiate the concept from electro-chemical storage technologies.

CONCLUSION

A large scale storage solution leveraging low cost and established molten salt thermal storage is presented. The goal of this paper is to present the feasibility of constructing such a large scale storage system with only commercially available components without requiring development of new technology. The use of CO_2 cycle heat pump is selected for converting electrical energy to heat due to the industrial experience and availability of suitable high temperature compressors, expanders and heat exchangers. CO2 is the preferred fluid as it keeps health & safety hazards to a minimum while allowing sufficiently high specific power or conversely reduced size of the turbomachinery. The discharging cycle is maintained as a water steam cycle. For the best possible discharging efficiency, the highest temperature of 565°C of the molten salt should be achieved. However, due to compressor limitations the last part of heating of the salt from 480°C to 565°C is performed with an electrical heater. This reduces the net COP, but enables optimum use of molten salt, reduced number of parallel heat pump systems and allows high water–steam cycle efficiency. Typical performances well above 50% of gross round trip efficiencies are obtained. From a cost point of view, large sizes of the storage solution benefit from large economies of scale; primarily on engineering, construction and large equipment for water steam cycle components and heat exchangers. For large scale solution above 6 hours of storage, the AMSES solution presented in this study can obtain significantly lower cost of electricity than the reference electro-chemical battery based on Lithium ion technology, if co-located and coupled with a large scale photovoltaic power plant. Additionally, a large potential for further cost reduction and performance improvement is identified, which will bring storage enabled PV plants to have comparable levelised cost of electricity to that from a PV plant with no storage.

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Dr. Vipluv Aga works as lead engineer for solar and storage systems at GE Renewable Energy, Baden, Switzerland dealing with new products in concentrated solar power, thermal storage and renewable integration. He received his PhD from ETH Zurich. He is currently project leader for new developments in electrical storage based on supercritical CO2 cycles and works with optimization techniques, business development for novel products and industrial and academic collaboration in the fields of solar energy and energy storage. He is a certified Project Management Professional.

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Dr. Richard Carroni is a lead engineer in the Customer Applications team of the Renewable Steam Plants unit of GE Renewable Energy. His current expertise lies in tendering various types of renewable steam plants, including CSP, geothermal and biomass units. Previous experience includes the development (for market introduction) of combined-cycle plants with carbon capture systems as well as ISCC plants, the development of lean-premix burners for hydrogen-rich combustion in gas turbines and R&D in the fields of lean-premix hydrogen combustion and also catalytic combustion. He is a certified Project Management Professional.

Bertrand Burcker is a performance calculation engineer for renewable steam plant in GE Renewable Energy. He has been involved in geothermal, biomass and concentrated solar power plant performance calculation and the plant performance tests. He is also responsible for system modeling for all novel innovative cycles.

Mathieu Ramond, Lead Process Engineer in the R&D organization of the Renewable Steam Plants business unit, joined Alstom in 2008. His expertise lies in know-how on process engineering for various power plant type as combined cycle, supercritical coal power plants, CFB power plants and CSP power plants.
In his role in the R&D unit of GE Renewable Energy in Belfort, France, he is responsible of the technical process development of molten salt storage technology. Since he joined Alstom (now GE) as process Engineer, he collaborated on various steam power plants for gas turbine combined cycle, coal fired power plants and circulating fluidized bed power plant and gained experience in process engineering and process lead.

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