Thermal energy storage evaluation in direct steam generation solar plants

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Abstract

Existing commercial parabolic trough power plants use thermal oil as a heat transfer fluid, with working temperatures in the region of 400 °C. In order to achieve more efficient generating systems, a second generation of parabolic troughs that operate at temperatures higher than 400 °C is being developed. One possibility Abengoa Solar is assessing is the use of direct steam generation (DSG) inside parabolic troughs in order to achieve higher temperatures; in a first stage heating up to 450 °C and in a second stage heating up to 550 °C. For the future market potential of parabolic trough power plants with DSG, it is beneficial to integrate thermal energy storage (TES) systems. Different TES options based on the most known technologies, steam accumulators, molten salts (MS), and phase change materials (PCM), are presented and compared in this paper. This comparison shows as main conclusion of the study that a combined system based on PCM-MS has a clear advantage in the ratio with 6 or more equivalent hours of storage, while with lower than 6 hours, steam accumulators are considered the best option.

Key-words: *Direct steam generation (DSG); concentrated solar power (CSP); thermal energy storage (TES); phase change material (PCM); accumulator; steam; molten salt*

1. Introduction

Direct Steam Generation (DSG) is a commercial technological option in solar power plants.

DSG eliminates the need for intermediate heat transfer liquids while increasing overall plant efficiency as well as reducing cost, increasing performance, and becoming a more environmentally friendly technology. This is due, in part, to the fact that the water inside the receiver tubes absorbs the concentrated solar energy, and changes from liquid state into saturated steam and, subsequently, into superheated steam. The steam produced in the solar field is fed directly to the turbine without the need of any heat exchanger. Compared to the other commercial technologies available in the market, it eliminates the oil/water heat exchanger or the molten salt/steam generator, incorporating water/steam separators. In addition, the limitations on the maximum trough solar field temperature imposed by the degradation of the thermal oil (up to 400 ºC) or the limitation of the working temperature of nitrate molten salts in solar tower power plants (up to 565ºC) disappear and, therefore, the technology allows access to more efficient high temperature power cycles. Furthermore, investment costs are reduced due to the elimination of intermediate equipment [1].

Currently there are four plants in the world operating with this technology in central receiver plants. PS10 [2] and PS20, both located in Spain, started commercial operation in 2007 and 2009, respectively, and they became not only the first two commercial solar towers in the world but also the starting point for the operation of the direct steam technology in saturated steam conditions. Second generation of DSG towers uses superheated steam technology. Superheated steam technology uses a second receiver, whose main function is to re-heat the steam produced by the first receiver (evaporator), thus allowing reaching higher temperatures. Khi Solar One [3] , a 50MWe superheated steam tower with 2 hours of storage in South Africa, and Ivanpah Solar Project [4], a 377MWe without storage in United States are in operation with superheated DSG technology.

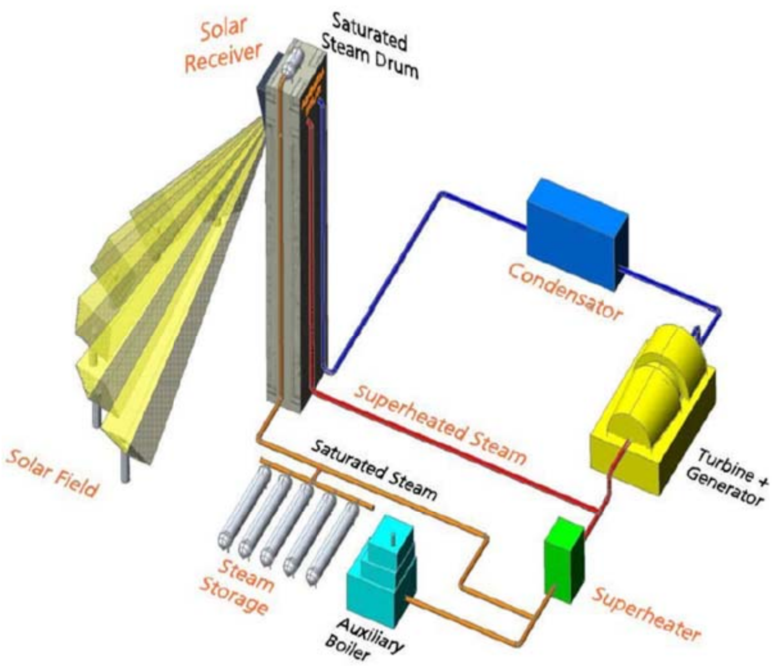

Figure 1 Schematic flow diagram of a direct steam generation tower plant (PS10 and PS20) with steam accumulator thermal energy storage system (source: Abengoa)

The main disadvantage of the direct steam generation is that there is no thermal energy storage (TES) systems for long storage time associated to this technology that are economically competitive with other types of systems like molten salts [1]. The DSG commercial plant uses steam accumulator, based on the Ruth accumulator system [5], for 1 or 2 hour of storage. Additionally important efforts have been done trying to integrate the TES technology within the DSG solar power generation at large scale.

One of the most studied solutions has been to split the TES system in three different units depending on the water/steam conditions: pre-heater, evaporator, and superheater [6]. Feldhoff et al. [7] studied different alternatives to solve the TES system combining sensible and PCM subsystems. While latent heat related to the steam evaporation is always given by a phase change material (PCM) system, the sensible heat associated to water preheating and steam superheating could be solved with different solutions: (a) concrete blocks, (b) PCM, and (c) molten salts storage tanks (Figure 1-right side). Therefore, an interesting DSG plant storage system would integrate a PCM system for preheating and evaporating and a configuration of two molten salt tanks for superheating the steam (Figure 1).

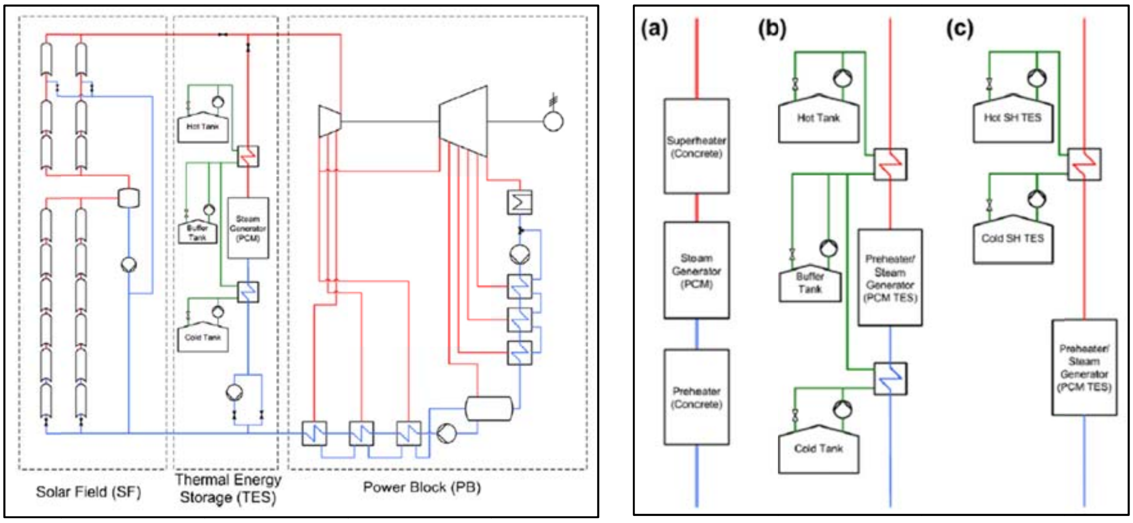

Figure 2. DSG plant configuration. Left: Overall layout of DSG plant with TES system integrated; Right: TES configurations alternatives for DSG technology

The aim of this study is to perform a cost comparison between new different energy storage configurations in DSG plants. Detailed performance and cost analyses were conducted to evaluate the economic comparison of the concepts described in this paper.

2. Thermal Energy System configurations

Three TES technologies (steam accumulator, molten salts and PCM) have been combined to optimize the DSG storage system. A more detailed description of the different considered TES options have been included in this section, explaining some of the main assumptions considered for each system during the evaluation.

2.1. TES technologies

2.1.1. Steam accumulators

State-of-the-art of thermal energy storage used for steam applications is the steam accumulator technology. Steam accumulators (also called Ruths storage systems) use sensible heat storage in pressurized saturated liquid water[5]. Steam is produced by lowering the pressure of the saturated liquid during discharge. For Rankine power cycles with high pressure water/steam, the direct storage of saturated or superheated steam in pressure vessels is not economic due to the high investment cost of the pressure vessels and the low volumetric energy density. Therefore, indirect storage system materials have been used in order to transfer the energy from the primary heat transfer fluid to a separate storage.

A steam accumulator consists of a steel pressure tank designed to resist high pressure and high temperature water/steam [8] [9]. For the design of such equipment it is important to consider thermal cycling during charge and discharge due to the change of the saturated conditions, so the material is able to withstand without any failure during the whole life of the plant. Limiting temperature gradients in the vessel walls is a key parameter to avoid thermomechanical stress on steam accumulators. Even if the materials commonly used for this kind of equipment is very well-known (e.g. boilers), corrosion phenomena should be taken into account regarding water content impurities.

Steam accumulators may be of horizontal or vertical (standing) design but the main operational differences are characterised by their physical orientation. Horizontal accumulators have relatively shallow water level and large water surface area which are properties in direct contrast with those of vertical accumulators.

Regarding the sizing, it will depend on the needs of storage capacity. There are limitations regarding the maximum size of the each steam accumulator, basically depending on the maximum operating pressure as well as transportation concerns to sites where solar plants are located. However, several units can be able to meet the total thermal energy storage capacity of the plant.

For power cycles with high pressure water/steam, the direct storage of saturated or superheated steam in pressure vessels is not usually economic due to high investment cost of the pressure vessels and the low volumetric energy density.

2.1.2. Molten salts

Molten salts are the most widespread indirect storage system in commercial solar plants due to its good thermal properties and reasonable cost [10], [11], [12]. Nowadays, molten salts provide a thermal storage solution for the two most mature CSP technologies available on the market (e.g. parabolic trough and tower) and could be used as direct and indirect storage depending of the selected plant philosophy. Both, trough and tower technologies, use the double tank system as thermal storage configurations. This concept was successfully demonstrated in solar thermal demo plants [13]: CESA-1 (Spain), Themis (France), Central Receiver Test Facility (USA), and Abengoa 8.1 MWhth storage capacity TES-MS (Spain) [14] and are now in commercial operation.

The molten salt fluids commonly used are nitrate mixtures with a weight composition of 60wt.% $NaNO_3$ and 40wt.% KNO_3, also called *solar salt*, which optimizes cost and thermal properties. These mixtures have been well known in the solar industry for decades with wide bibliographic information and proven feasibility at both pilot and commercial scale [15], [16], [17], [18]. Their prices are significantly stable in the market. However, corrosion phenomena should be taken into account regarding material compatibility due to impurity contents of these mixtures [19], [20]. Nevertheless, good performance with the most common materials used in the industry can be assured.

2.1.3. Phase change material (PCM)

PCM solutions have been usually related with direct steam generation (DSG) technology because their property of storing and delivering energy for a given temperature. Since steam exchanges heat at constant temperature when evaporates and condensates, the heat exchanged between a PCM and the steam requires less temperature differences between the storage media and the steam minimizing the exergy destruction [21] [22] and [23]. Another important parameter of PCM systems is the melting point of the material which is directly related with the steam discharge pressure in the DSG system. For a given melting point and temperature difference between the PCM and the steam, the evaporation pressure would also be fixed. Accordingly, maximum commercial Rankine power cycle efficiencies have been reported to be around 120 bar, being the associated discharge temperature close to 324 ºC and the maximum temperature of superheated steam around 550 ºC [24].

2.2. TES configurations for DSG systems

Different TES configurations have been evaluated to be applied in DSG system at different capacities.

2.2.1. Option 1: Accumulators with superheating (**AccumSH**)

The first TES option considered is a steam accumulator system with superheating capabilities. In this option, used in the Khi Solar One [1]; the accumulator system is charged using saturated steam from the main separator tank at the return point from the evaporator solar field. The maximum allowable pressure in the accumulator tanks is limited to 110 bars as a result of the limitations for the receiver tubes in the field. When the system is charging the additional water required for the accumulators is feed to the deaerator and reduces the power block efficiency while charging. The layout of the plant with the incorporation of this system is shown in Figure 3.

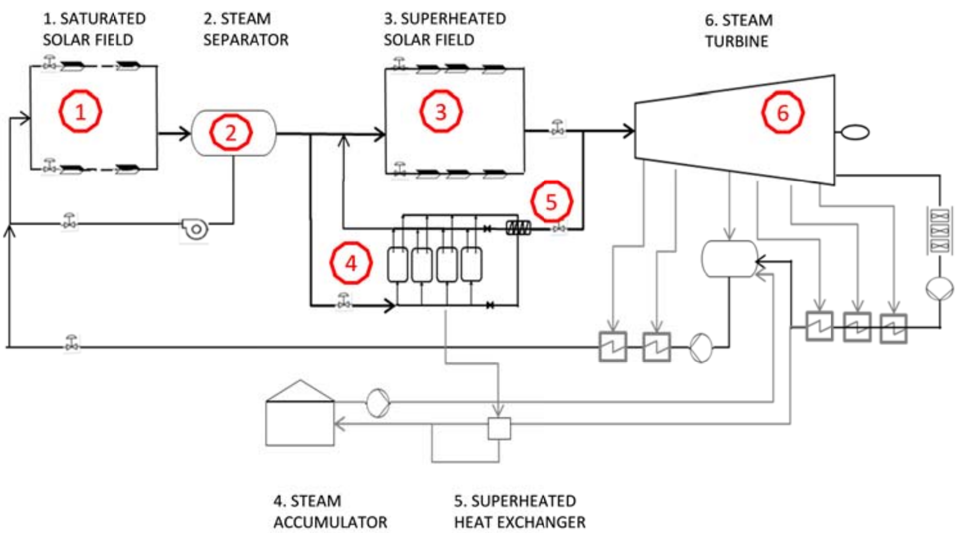

Figure 3. Layout of plant with AccumSH

To be able to produce superheated steam, this system has pairs of accumulators with the larger volume accumulator for generating saturated steam and a smaller volume accumulator for superheating that saturated steam through the use of a steam to steam heat exchanger. The optimized design, based on optimizing the discharge process, has for each pair a larger tank volume (base accumulator) of 4,500 m^3 and a smaller tank volume (superheating tank) of 1,500 m^3.

All accumulators are charged from saturated solar field and during the discharge process the system is able to discharge at two different pressure levels (35 bar and 22 bar) to produce superheated steam with 50°C of superheat. At the end of the discharge cycle there will still be some steam in both tanks at pressures that are too low to maintain an output stream at 50°C of superheat.

At this point the performance estimates have not taken into account the possibility of using the energy left in the system after discharging either in the turbine or in other parts of the plant. It is important to note that when operating from storage the turbine is operating at conditions lower than the nominal ones and the discharge time is significantly longer than equivalent full load hours of storage. For example three hours of energy or enough energy to produce the design gross power for three hours takes 10.5 hours of discharging time.

2.2.2. Option 2: Accumulators and two-tank molten salt (**AccumMS**)

The second considered TES option uses steam accumulators for storing and producing saturated steam and a two-tank molten salt system for storing energy to superheat the saturated steam produced by the accumulators up to 415°C. This system is charged with superheated steam from the outlet of the superheating field when more steam is being produced than the turbine can handle. First heat is extracted from this steam using a heat exchanger with the two-tank molten salt system so that the steam exiting the heat exchanger is at its saturation point. This saturated steam is fed directly to an accumulator tank. Similarly to the AccumSH option, during charging the extra water that will be stored in the accumulator is injected to the deaerator. The layout for the incorporation of this TES option is shown in Figure 4.

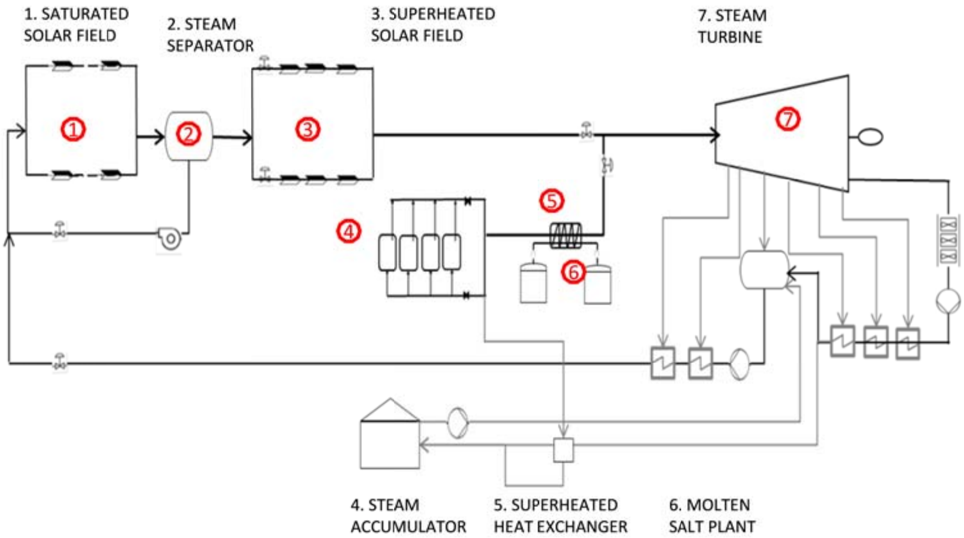

Figure 4. Layout of plant with AccumMS

During the discharging process the system will operate at two different levels producing steam at 82 bars up to 415°C and at 67 bars up to 415°C. At the end of the discharging cycle the accumulator tanks will have a pressure of 69 bars. Similarly to the other accumulator considered options there will be unusable energy remaining in the accumulators at the end of the discharge cycle.

This option shows a deviation between the thermal energy required during the charging process and the thermal energy required from cycle during the discharging process. With the goal to take maximum advantage of the storage system, it has considered an alternative based on charging the MS system using only the mass flow necessary so that the total mass of MS requested during discharging process is the same quantity as the total mass requested during charging process, the rest of the superheated steam is injected directly at steam accumulator as superheated steam.

The main advantage of this strategy of charge is that a balance of the thermal energy during charging/discharging process is achieved. Since the steam at the inlet of the steam accumulator is superheated, the charging time is lower but on the other hand during discharging the steam is saturated and not superheated, thus the exergy is lower.

2.2.3. Option 3: Phase Change Material (PCM) and two-tank Molten salt (PCM-MS)

The third TES option considered at this point uses a phase change material to produce saturated steam and a two-tank molten salt system for storing energy to superheat the saturated steam from the PCM system up to 521°C. Like the AccumMS option, this option will be charged using the excess superheated steam produced in the superheating field, and heat is extracted from this steam using a heat exchanger with the two-tank molten salt system so that the steam exiting the heat exchanger is at its saturation point. The resulting saturated steam is fed directly into the PCM system, which extracts the energy so that saturated water exits the system. This water is combined with water from the power block to return to the solar field inlet. Since the water is returned to the solar field, the requirement of adding water to the deaerator, as in the accumulator options, is removed. During discharging the system is designed to produce steam at 95 bar and 521°C. The layout of the plant with this option is shown in Figure 5.

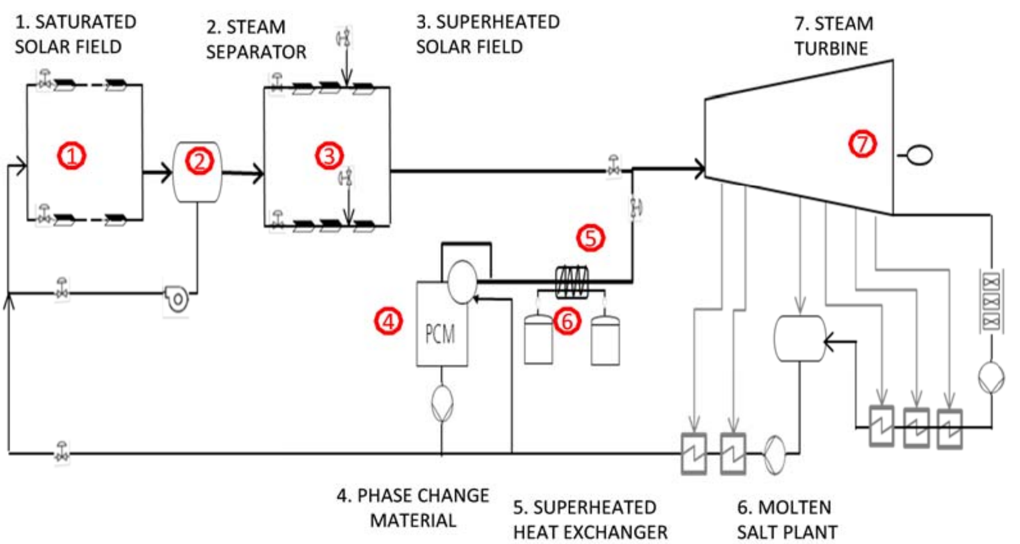

Figure 5. Layout of plant with PCM-MS option

3. Performance evaluation methodology

This section discusses the methods and the base assumptions used to evaluate the impact of each considered TES option on the annual plant performance. For each TES technology the annual plant performance was calculated for an optimized plant layout while minimizing the differences between the plants. For each TES option the plant parameters listed in Table 1 were kept constant.

Table 1. Constant Plant Parameters

Parameter	Unit	Value
Design Gross Power	MWe	147
Collector Type	-	E2
Plant Location	-	Mojave Site
Turbine Inlet Conditions	bar/°C	100 / 550
Power Cycle Type	-	Dry cooling, no turbine pump, deaerator preheating

The storage systems were modelled using matrices based on the available energy and the energy required to run the power block. This means that the hourly or sub-hourly behaviour of the storage system was not captured in full detail in the model. We assume that all the TES have 5% of heat loss from the system overnight to try to capture some of the efficiency losses of the system. For the PCM-MS option the annual predictions were also obtained from a model.

For each option a range of solar field sizes where examined for different design hours of storage. For AccumSH 1, 2, and 3 hours of storage were examined. For the two options with molten salt 3, 6, and 10 hours of storage were evaluated. The longer hours of storage for the AccumSH option were not considered because the actual discharge time would be longer than 12 hours. In order to make performance and cost estimates for each considered TES design different assumptions and limitations were applied based on the design requirements. Where possible, these assumptions were kept constant to reduce differences in the results due to varying assumptions.

3.1. Assumptions for AccumSH

For the AccumSH design a detailed analysis was performed to optimize the size and operating conditions of the accumulator tanks. The following assumptions were used in this analysis and in the annual performance estimate:

- Tanks designed with sufficient insulation to limit heat loss to 5^{o}C in a 24 hour period at maximum tank level, minimum external temperature, and maximum wind speed.
- Minimum water level will cover the tank ejectors to ensure proper function of the tank.
- During discharging, flow originates from one base tank and superheating of this flow occurs from one superheating tank at a time.
- Maximum tank pressure limited to 110 bar.

One of the main sources of assumptions for the performance of this TES system is the design pressure levels during the discharging of the system. The restrictions and assumptions used to optimize the pressure levels are as follows:

- Actual discharge time cannot exceed 12 hours.
- Superheating accumulators are designed to have minimal oversizing and maximum utilization.
- Pressure losses from the control value on the tank outlets will be around 2 bar.
- Production of superheated steam at 50^{o}C of superheat requiring the superheater accumulators to have temperature 57^{o}C higher than the base accumulators.
- Balance of increasing the superheater tank volume for higher pressure capacity (better cycle performance) and the increased cost for larger volume tanks.

The performance estimates for the system were made based on the material and energy balances on each part of the system and on the system as a whole unit. The result of the assumptions was two levels of pressure discharge (one at a high and the other at a low pressure) and a superheating accumulator volume smaller than the base accumulator volume for reduced costs. Based on the optimum tank designs, performance during charging and discharging was estimated for a range of desired hours of storage and matrices were compiled relating the energy in the system to the electrical power produced and the actual discharge times for the two different operational levels.

3.2. Assumptions for AccumMS

For the AccumMS design a detailed analysis was performed to optimize the size and operating conditions of the system. The following assumptions were used in this analysis and in the annual performance estimate:

- Accumulator tanks designed with sufficient insulation to limit heat loss to 5°C in a 24 hour period at maximum tank level, minimum external temperature, and maximum wind speed.
- Minimum accumulator water level will cover the tank ejectors to ensure proper function of the tank.
- During discharging, flow originates from one accumulator tank at a time.
- Maximum accumulator tank pressure limited to 110 bar.
- Need to balance the benefits of the discharge pressure and the actual time for discharging.
- Designed with minimal oversizing and maximizing utilization.
- Charging and discharging strategy for molten salt will compensate for pinch point differences and useful energy gain.

. The result of the assumptions was two levels of pressure discharge at a high and low pressure from the accumulator tanks with sufficient superheating occurring from heat exchange with the two tank molten salt system. Based on the optimum tank designs, performance during charging and discharging was estimated for a range of desired hours of storage and matrices were compiled relating the energy in the system to the electrical power produced and the actual discharge times for the two different pressure levels.

3.3. Assumptions for PCM-MS

For the PCM MS design a detailed analysis was performed to optimize the size and operating conditions of the system. The following assumptions were used in this analysis and in the annual performance estimate:

- Desired PCM discharge pressure of 97 bar with a 2 bar pressure drop in the heat exchanger resulting in discharging outlet pressure of 95 bar.
- Design system to produce maximum temperature of superheated steam possible.
- Pinch point in heat exchanger of 5°C.

In order to maximum the outlet steam temperature from the heat exchanger the cold salt temperature should be as close to 265°C as possible. With this cold temperature and the restriction of a pinch point of 2°C, the system can produce steam at around 521°C during the discharge cycles. At higher cold salt temperatures it is impossible to produce steam near even 500°C. Under the desired cold salt temperature assumptions the following operational conditions are assumed:

- Charging
  - Charging steam entering at 540°C and 106 bar.
  - Cooling of the superheated steam to saturated steam results in steam at 314°C and 104 bar.
  - Salt temperatures increases from 265°C to 525.7°C.
  - Steam exits the PCM system as saturated water at 314°C and 104 bar.

- Discharging
  - Cold salt used in preheating starts at 312°C and returns to the cold tank at 265°C.
  - Water from preheater enters PCM at 263.8°C and exits at 309°C and 97 bar.
  - Saturated steam from PCM enters superheater at 309°C and 97 bar and exits at 521°C and 95 bar.
  - Hot salt in used for superheating starts at 525.7°C and returns to cold tank at 312°C.

The final summary of the discharge conditions are included in Table 2. Energy balances were performed on the systems to generate estimates for the annual performance of the system for different sizes.

Table 2. Summary of discharge conditions

	AccumSH	AccumMS	PCM-MS
Storage technology	Steam accumulators	Steam accumulators for saturated phase and molten salt for superheating	PCM for saturated phase and molten salt for superheating
Charge conditions	Saturated steam temperature with 110 bar max	540ºC and 106 bar	540ºC and 106 bar
Pressure	- Sliding pressure - Max 110 bars in accumulators	- Sliding pressure - Max 110 bars in accumulators	- 95 bars
Temperature	- 50ºC superheating	- 490ºC	- 521ºC

3.4. Cost Assumptions

This section focuses on the cost assumptions used to evaluate the viability and compare the different storage options. For the field components and power block costs, the same cost assumptions were used for these studies with TES as were used previously in the studies of the plant without storage. Cost estimates were made for each of the considered TES options for each of the different design hours of storage tested. The cost assumptions used for the accumulator system with superheating are listed in Table 3.

Table 3. Cost assumptions for AccumSH

Accumulator system	Total Cost [$]	Total Cost [$/kWhe]
1 Hour System	$28,496,508.90	$193.85
2 Hours System	$56,993,017.80	$193.85
3 Hours System	$85,489,526.70	$193.85

The accumulator tank costs are dependent on the volume of the tank and the design operation pressure. Since the superheater accumulator will need to operate at a higher pressure the cost per volume is higher. For the different design hours of storage the total cost per kWhe produced is the same because the system is designed so one hour of storage is one base accumulator and one superheater accumulator.

The cost assumptions used in the accumulator and two-tank molten salt design consider the same cost for the base accumulator tank as the accumulator system with superheating. The two-tank molten salt part of the system is based on a cost per thermal energy stored with the assumption that for each accumulator in the system there is a set amount of thermal energy required in the two-tank molten salt system. The cost assumptions for the two-tank molten salt and the full AccumMS systems are listed in Table 4, which shows that the cost of the two-tank molten salt system in terms of cost per installed thermal capacity decreases with increasing size due to economies of scale.

Table 4. Cost assumptions

Hours of storage [hr]	MS system [$/kWh$_{th}$]	AccumMS system [$/kWh$_e$]	PCM-MS system [$/kWh$_e$]
3	102.58	336.14	216.46
6	95.37	358.45	218.48
10	59.99	320.28	180.3

For the TES option PCM-MS, the costs assumptions for the two-tank molten salt system are the same as the cost assumptions used for AccumMS. The cost assumptions used for PCM-MS in terms of cost per installed thermal capacity are listed in Table 4 and the total costs for the two parts of the PCM-MS system are listed in Table 5.

Table 5. Cost assumptions for PCM-MS

Item	Cost [$/kW$_{th}$]
PCM	65.65
MS system for 3 hour	102.58
MS system for 6 hours	95.37
MS system for 8 hours	62.31
MS system for 10 hours	59.99

4. Economic Analysis

This section discusses the results for the optimum plant layouts for the considered TES systems. The main result values for the optimum plants for the three different design hours of storage are listed in Table 6. In this table the power and cost values have been adjusted with the following considerations for fairer comparison with other projects:

- Power
    - Corrected with degradation factor of 0.97
    - Modified with Monte Carlo factor of 0.99. Monte Carlo simulations are used to model the probability of different outcomes in a process that cannot easily be predicted due to the intervention of random variables [28]
    - Modified availability of the solar field at 0.97
    - Adjusted irradiation for Lathrop Wells Site (2760 kWh/m^2·year)

- Cost
    - Includes all of the direct capital costs for the field, power block, and TES system
    - Adjusted by 10% to account for indirect costs like engineering, guarantees, and insurance
    - Operational cost are not included

Table 6. Optimum plant layouts for the considered TES systems

Design		Adjusted Annual Gross Capacity [MWh_e]	Adjusted Annual Net Capacity [MWh_e]	Adjusted Total Plant Cost [M$]
AccumSH	1 hour	388,117	355,420	508.45
	2 hours	429,031	392,988	573.25
	3 hours	459,578	420,846	632.19
AccumMS	3 Hours	466,564	424,187	739.99
	6 Hours	538,206	485,323	1,015.85
	10 Hours	---	---	---
PCM-MS	3 Hours	496,718	459,475	676
	6 Hours	629,193	584,956	894
	10 Hours	784,912	731,415	1,096

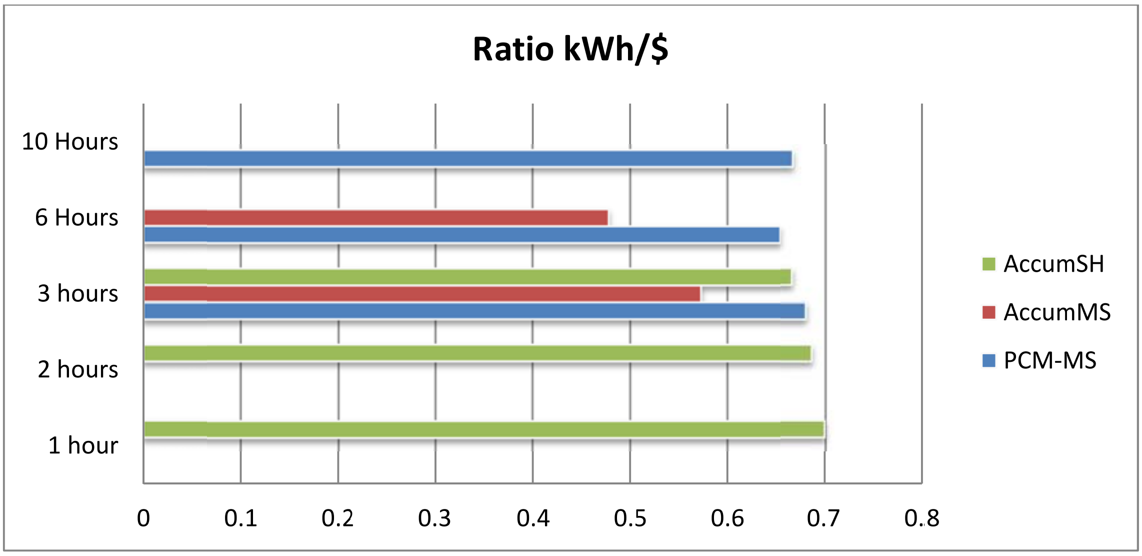

Figure 6. Ratio kWh/$ in the different TES layouts

The number of superheater loops in the configuration AccumSH is the not affected by the hours of storage. This is because the charging of the TES system is occurring using saturated steam from the separator tank and the superheater field is only used to supply superheated steam to the power block. On the other hand, the optimum number of evaporator loops increases with increasing design hours of storage. A larger evaporator field can charge the TES system more often and at a faster rate at lower irradiations. However, the usefulness of increasing the size of the evaporator is limited by the corresponding increase in costs and the fact that the charging rate is limited to 110 kg/s. It is possible to observe that adding more hours of storage increases the annual power production and the total plant cost. Since both values increase with the larger storage size the ratio of annual net power over total plant cost is useful for comparing the different designs.

Figure 6 clearly shows that for the AccumSH system, the ratio of annual power produced to total plant cost increases with fewer hours of storage. This result is a combination of the efficiency losses occurring within the storage system, the turbine operating at less than nominal efficiency while the TES system is operating, and the added cost of the TES system. It is important to note that while the design with 1 hour of storage had a higher ratio there are some disadvantages to the 1 hour design. Having only 1 hour of storage reduces the impact the TES system can have on the plant dispatchability and limits the amount of time that the plant is operating on a daily basis. Also the length of time required during the discharge phase for this design will also limit these benefits regardless of the design size.

For the AccumMS, Figure 6 demonstrates that both the optimum number of evaporator and superheater loops is changing with the desired hours of storage for this storage option. This is a result of the storage system being charged using the excess superheated steam produced in the superheater field. In order to produce more excess superheated steam the size of both the evaporator and superheater solar fields need to be increased. The usefulness of increasing the solar field size is limited by a limited charging rate of 110 kg/s and the trade-off of the added cost of the solar field for the power gained from storage. This is particularly noticeable for increasing the superheater field size since the superheater field costs more per area of solar field. Similar to the previous case, adding more hours of storage results in an optimum plant size that is more expensive but produces more energy. As a note, the 10 hours of storage case was not included in this table because during the analysis it was determine that the 110 kg/s limitation made the current power block design not optimum for the higher hours of storage case. The ratios of the annual net power over that total plant cost capture the impact of the trade-off of the increased power for the increased plant cost.

For the PCM-MS system, Figure 6 demonstrates that both the optimum number of evaporator and superheater loops is changing with the desired hours of storage for this storage option as the previous TES option assessed. Similar to the previous cases, adding more hours of storage results in an optimum plant size that is more expensive but produces more energy. The ratios of the annual net power over that total plant cost capture the impact of the trade-off of the increased power for the increased plant cost. As with the other two designs increasing the design hours of storage resulted in a decreased ratio for the optimum plant layout.

The effect of the cost of the AccumSH TES system is examined in more detail in Table 7. For the 1 hour storage design, a 10% shift in TES cost results in around a 0.5% shift in the ratio, with a lower cost leading to a higher ratio and a higher cost leading to a lower ratio. For the 3 hours storage design a 10% shift in TES cost is approximately a 1.3% shift in the ratio. This suggests that the TES cost becomes more important for the calculated ratio value the larger the TES is, which corresponds to the fact that the higher cost of larger storage systems represents a larger percentage of the total plant cost.

Table 7. Cost Sensitivity Analysis on TES Costs for AccumSH

Cost Sensitivity On Total TES Cost [kWhe/$]	Variation in TES Cost					
	-10%	0%	10%	20%	30%	40%
1 hours	0.7030	0.6990	0.6951	0.6912	0.6873	0.6835
2 hours	0.6925	0.6855	0.6787	0.6720	0.6654	0.6590
3 hours	0.6749	0.6657	0.6567	0.6479	0.6394	0.6311

Table 7 clearly shows that the ratio of annual power produced to total plant cost increases with fewer hours of storage, which is the same trend seen with the AccumSH option. The effect of the cost of the TES system on these ratios is examined in more detail in
Table 8, Table 9, and Table 10.

The cost sensitivity analysis in

Table 8 shows the effect on the ratio of annual net power over the total plant cost for variations in the entire TES system cost. For this TES option, a 10% variation in the total cost is a 2% variation in ratio for the 3 hour design and 3.2% variation for the 6 hour design. There is a larger change for this option, in comparison with the AccumSH design, because the TES cost for this option are a larger percentage of the total plant cost. Since this TES option has two separate components the cost sensitivity analysis was expanded to examine the effect of variations in the cost of the accumulator tanks and the cost of the two-tank salt system.

The comparison of the results shown in Table 9 and Table 10 clearly demonstrates that a change in the accumulator cost will have a larger impact on the ratio than a corresponding percent change in the molten salt system cost. This is the expected result since for the different design hours of storage the salt system is around 20% of the total TES system cost and suggests that reducing the accumulator system cost should take priority over reducing the molten salt system cost.

The effect of the cost of the TES system on these ratios is examined in more detail in Table 11, Table 12, and Table 13

Table 8. Cost Sensitivity Analysis on TES Costs for AccumMS

Cost Sensitivity On Total TES Cost [kWh_e/$]	Variation in TES Cost					
	-50%	-25%	-10%	0%	10%	25%
3 hours	0.6411	0.6053	0.5856	0.5732	0.5613	0.5444
6 hours	0.5718	0.5206	0.4940	0.4778	0.4625	0.4414

Table 9 Cost Sensitivity Analysis on Accumulator Tank Costs for AccumMS

Cost Sensitivity On Accumulator Tank Cost [kWh_e/$]	Variation in TES Cost					
	-50%	-25%	-10%	0%	10%	25%
3 hours	0.6248	0.5979	0.5828	0.5732	0.5639	0.5505
6 hours	0.5430	0.5083	0.4895	0.4778	0.4665	0.4507

Table 10. Cost Sensitivity Analysis on MS System Costs for AccumMS

Cost Sensitivity On MS System Cost [kWh_e/$]	Variation in TES Cost					
	-50%	-25%	-10%	0%	10%	25%
3 hours	0.5871	0.5801	0.5760	0.5732	0.5705	0.5665
6 hours	0.4936	0.4855	0.4808	0.4778	0.4747	0.4702

The cost sensitivity analysis in Table 11 shows the effect on the ratio of annual net power over the total plant cost for variations in the entire TES system cost. For this TES option, a 10% variation in the total cost is a 1.32% variation in ratio for the 3 hour design and 2.25% variation for the 10 hour design. The increasing variation for the larger hours of storage design is the same effect observed with the other TES options. Since this TES option has two separate components the cost sensitivity analysis was expanded to examine the effect of variations in the cost of the PCM block and the cost of the two-tank salt system, as shown in Table 12 and Table 13.

The comparison of the results shown in Table 12 and Table 13 clearly demonstrates that a change in the PCM system cost will have a larger impact on the ratio for larger capacity of TES than corresponding percent changes in the MS system cost.

Table 11. Cost Sensitivity Analysis on TES Costs for PCM-MS

Cost Sensitivity on Total TES cost [$kWh_e/\$$]	Variation in TES Cost					
	-50%	-25%	-10%	0%	10%	25%
3 hours	0.728	0.703	0.689	0.680	0.671	0.657
6 hours	0.729	0.689	0.668	0.654	0.641	0.622
10 hours	0.754	0.708	0.683	0.667	0.652	0.631

Table 12. Cost Sensitivity Analysis on PCM Costs for PCM-MS

Cost Sensitivity on PCM System Cost [$kWh_e/\$$]	Variation in PCM Cost					
	-50%	-25%	-10%	0%	10%	25%
3 hours	0.704	0.692	0.684	0.680	0.675	0.668
6 hours	0.692	0.673	0.661	0.654	0.647	0.636
10 hours	0.721	0.693	0.677	0.667	0.657	0.643

Table 13. Cost Sensitivity Analysis on MS System Costs for PCM-MS

Cost Sensitivity on MS System Cost [$kWh_e/\$$]	Variation in MS Cost					
	-50%	-25%	-10%	0%	10%	25%
3 hours	0.702	0.691	0.684	0.680	0.675	0.669
6 hours	0.686	0.670	0.660	0.654	0.648	0.639
10 hours	0.695	0.681	0.673	0.667	0.662	0.654

5. Conclusions

This paper has compared three different TES configuration in DSG plants: accumulators with superheating (AccumSH), accumulators and two-tank molten salt (AccumMS), and phase change material and two-tank molten salt (PCM MS). The conclusions in term of cost and feasibility of the systems depend on the capacity of the storage system in hours of discharge, being the best options AccumSH for storage lower than 3 h and Accum PCM for more than 6 hours of storage.

The study has shown that even though the AccumSH and PCM MS designs have similar results for 3 hours of storage, the PCM MS design has the significant advantage of having a much shorter discharging time and the discharging cycle occurs closer to nominal condition. This difference becomes important if the plant design is required to produce energy for storage in a specified amount of time or if the energy produced for storage is required to be closer to nominal conditions. Also since the resulting ratios were very similar it is important to repeat the analysis for one of the designs with the same model used for the other design. This would provide a fairer comparison and a more accurate idea of the relationship between the two options.

Comparing the 2 options for 6 h of storage; PCM-MS has 37% higher ratio than Acum-MS, and the main reason for this is the TES cost per production from TES is 55% lower in the first case. PCM MS options for more three hours of storage shows that the PCM MS option starts to produce much more power from storage than the AccumMS option which starts to level out at around 135 GW_e annually from TES. This is a consequence of the limitation to the charging mass flow rate for the AccumMS option. The mass flow rate is limited to 110 kg/s for this option because of the need to preheat water for the accumulators during charging in the deaerator. A higher mass flow rate would affect the turbine operation and would require a different design for the turbine. Since the flow rate is limited the maximum number of accumulators that can be charged in a 12 hour period is around 12 tanks, which results in the larger systems being underutilized. On the other hand, PCM MS does not require extra water preheating in the deaerator since during charging the water exits the storage system and is mixed directly with the water returning to the field.

Regarding to the AcumSH and PCM-MS systems, the main conclusion of the study is that based in the cost assumed for the two systems, the PCM-MS has a clear advantage in the ratio with 6 or more equivalent hours of storage.

Finally the study concludes that with lower than 3 hours, the Acum-SH is considered the best option because the higher technical maturity and the higher reliability in the estimated cost.

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