INDIRECT MOLTEN SALTS STORAGE MANAGEMENT AND SIZE OPTIMIZATION FOR DIFFERENT SOLAR MULTIPLE AND SITES IN A PARABOLIC TROUGH SOLAR POWER PLANT

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1. Abstract

Future challenges for solar thermodynamic technology are a significant reduction in the Levelized Cost of Electricity (LCOE), together with performance and availability improvements through design and management optimization. The application of thermal energy storage allows reducing transients due to weather variability and extending the plant operating hours from day-light to night-time with increased flexibility and economic advantages.
This work investigates the economic optimization, from LCOE point of view, of a two-tank indirect molten salts thermal storage in a solar plant based on parabolic trough technology. A 24 hours forecast thermal storage management is supposed in order to achieve the best solar energy harvesting through an optimized daily operation planning.
The optimal thermal storage size results from a trade-off between investment cost reduction and electricity production increase. A sensitivity analysis on storage size is also carried out for different solar multiples (SM) and geographical sites.

Keywords: parabolic trough, thermal storage, LCOE, storage size optimization

2. Introduction

Fossil fuels are currently satisfying most of the global energy demand but in the future they could be gradually substituted by renewable energy sources, thus limiting pollutants and greenhouse gas emissions into the atmosphere. Among the available renewable energy sources, solar energy could play a fundamental role in terms of satisfying energy demand, in particular in countries boasting high solar radiation.
Solar thermodynamic technology, as opposed to photovoltaic technology, has significant margins in electricity cost reduction, as considerable scale effects are expected in terms of the cost-performance ratio. Moreover, it allows for thermal storage, with possible decoupling of the electricity production from the energy source, that is a fundamental aspect in view of the unpredictable behaviour of sun radiation. It is worth noting that this last feature is not easily achievable with other renewable plants, and will be of upcoming importance in the next years, due to the increasing diffusion of renewables. In addition to this, a storage tank allows to increase working hours and electricity production of a plant, thus limiting part load efficiency penalization and in some cases lowering electricity costs.
This work explores the possibility of LCOE reduction for a mid-size commercial parabolic trough plant, obtained through the adoption of a heat storage system. The considered plant technology is based on synthetic oil as heat transfer fluid (HTF) in the solar field and a two-tank indirect thermal storage with molten salts. Actual investment costs are considered and the operating management of a real storage system has been optimized on the basis of a 24 hours forecast, in order to maximize the electricity production. Three geographical locations have been considered, with different latitudes and direct solar radiation. For each site the minimum value of LCOE can be found at different combinations of solar multiple and storage size.

3. Reference case and design conditions

According with the purpose of this work all the studied plants have the same power block configuration with the same design gross power output (50 MW) but different solar field and heat storage sizes.
The reference case chosen for simulations is similar to a commercial operating plant employing parabolic trough collectors, synthetic oil as HTF in the solar field and a molten salts indirect storage system. The chosen reference plant is analogous to Andasol 1 in Spain [1] [2], with about 50 MW design gross power output. For the reference plant a solar field with Solar multiple (SM) equal to 2 and a heat storage capacity of 7.7 equivalent hours are considered (DNI at design conditions of 800 W/m^2).
Reference plant is modelled with the commercial software Thermoflex 21® (TF21) [3] and plant layout is reported in Figure 1.

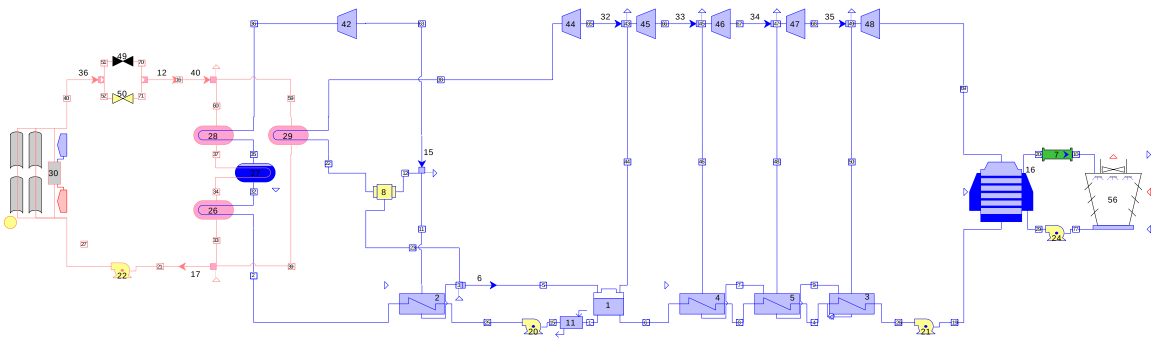

Figure 1. Reference case power plant layout (TF21 screen shot)

Power block is a common RH steam cycle with a HP turbine inlet steam temperature and pressure of 370°C and 100 bar respectively. Primary heat is provided by hot synthetic oil, cooled down in a heat exchanger section from a temperature of 393°C to 290°C. High pressure heat transfer is performed in three different heat exchangers: a shell and tube economizer, a pool boiling evaporator and a shell and tube superheater. Reheating heat exchanger has a design similar to superheater and it is placed in parallel with the whole high pressure primary heating line. High pressure steam turbine discharge pressure value is equal to 19 bar in order to preheat pressurized feed water up to 220°C in the last preheater. Feed water heating is performed in a deaerator and four preheaters (three at low pressure and one at high pressure) fed with five regenerative steam bleedings taken from HP and LP steam turbine casings (last preheater is fed by the steam taken from HP turbine outlet). Condensing pressure of 0.08 bar is chosen considering a wet cooling tower system. All power block components are modelled in TF21 choosing engineered PEACE components to obtain an exhaustive description of both thermodynamic behaviour and economic investment cost prediction.
Power production and power block consumptions, equal for all the investigated plants, are reported in Table 1.

Gross Power	50200	kW
Condenser and feedwater pumps	910	kW
Cooling water pump	540	kW
Condenser Fans	631	kW
Other auxiliaries	582	kW

Table 1. Power block design parameters.

Solar field is composed of several loops of EuroTrough solar collector assembly and Solel receiver tubes arranged in a “H” configuration. Dowtherm A [4] synthetic oil is considered as HTF in the solar field and an indirect two tanks thermal storage using a 60% $NaNO_3$- 40% KNO_3 molten salts mixture [5] is assumed.
Design DNI is the same for all the plants and its value is assumed equal to 800 W/m^2 with zero incident angle. Solar field section design is modelled adopting the component already implemented in Thermoflex and assuming component performances that represent commercial devices characteristics. Main assumptions

related to mirror reflectivity, glass transmission and coating absorbance are taken according to the data provided by manufacturers [6] [7] [8]. Reference solar field data are reported in Table 2.

Reflector aperture area	509204	m2
Number of loops	156	
Loop length	600	m
Reflector aperture width	5.77	m
Collector length	150	m
Solar field and Storage pumps consumption	2936	kW

Table 2. Solar field design data

4. Off-design operation

Yearly simulations are performed for three different sites: Sevilla (ES), Las Vegas (USA) and Darwin (AUS) that appreciably differ in annual DNI energy, site average temperature, relative humidity and geographical coordinates. Site weather data are taken from NREL TMY3 database [9] and from EPW [10] for Sevilla, with an hourly timeframe discretization.

Main data for each location are summarized in Table 3 and graphically represented in Figure 2. It is possible to notice that high annual irradiation and low average wet bulb temperature in Las Vegas make this site particularly attractive for concentrating solar power plants while less impressive results are expected for Sevilla, due both to a lower average DNI and higher temperature caused by higher relative humidity during all the year.

The almost constant monthly average DNI trend in Darwin allows operating power plant closer to the design point with advantages related to the limitation of efficiency decay caused by part-load operation.

Site		Sevilla (ES)	Las Vegas (USA)	Darwin (AUS)
Latitude	°	37.42	36.08	-12.4
Longitude	°	-5.9	-115.15	130.9
Time zone		1	-8	9.5
$T_{amb,\ dry\ (average)}$	°C	18.3	19.8	27.1
RH $_{(average)}$	%	62.6	29.6	69.7
$T_{amb,\ Wet\ Bulb\ (average)}$	°C	13.3	9.5	22.6
Hours with DNI>0	h	3893	4581	4742
DNI $_{(average\ DNI>0)}$	Wm^{-2}	536. 8	565.8	442.2
Annual DNI	GWh/m^2	2.09	2.59	2.10

Table 3. Ambient data for the three selected location sites.

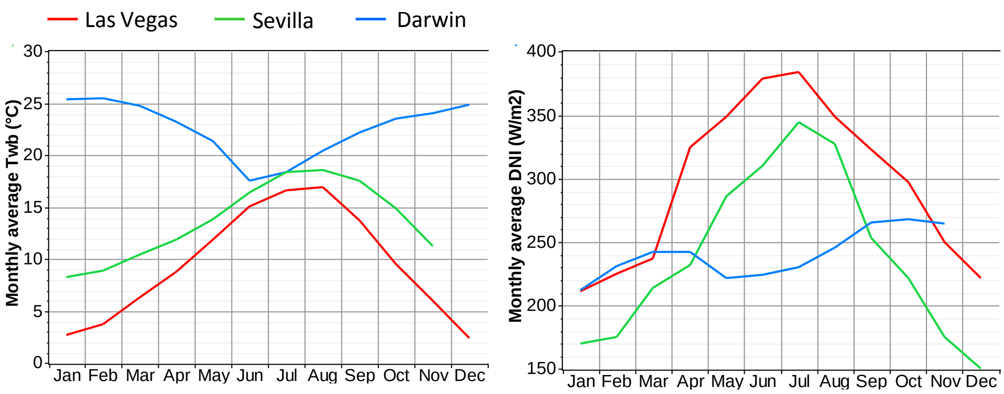

Figure 2. Monthly average wet bulb temperature and DNI for Sevilla, Las Vegas and Darwin.

However, in general solar field and power block operate in off-design conditions for a great part of the year due to the not constant daily and seasonal DNI as well as to ambient temperature trends.

All the components performances are obtained using TF 21 part load solving approach [3] that allows finding new system operating conditions with a low computational time.
Solar field TF21 off-design takes into account most of the effects that contribute to reduce solar field performance like irradiance dilution due to incident angles greater than zero, IAM (Incident Angle Modifier) effect, end losses and rows mutual shading [11].
In TF21 radiative heat losses from receiver to the ambient are computed considering a constant coating emissivity: in this way the evaluation of solar field thermal efficiency would be penalized in the first hours of the day when oil average temperature is below its nominal value. In order to improve model accuracy and correspondence with reality, in our model receiver emissivity is updated every timeframe with reference to the average temperature reached in the previous hour simulation. In addition also transients due to solar field heat capacity are taken into account to obtain a more exhaustive description of the global off-design behavior during start up and shout down. Thermal storage heat losses are computed taking into account the temperatures of solar salts and the fluid level in cold and hot tanks [2].
Power block off-design is due both to variation in steam enthalpy and mass flow and condensing pressure: the first effect is caused by variation in HTF mass flow and temperature, the latter depends on the variation of ambient temperature and humidity affecting the wet cooling tower operating conditions.
The different steam turbine sections are grouped in the Steam Turbine Assembly component available in TF21 [3] that guarantees good accuracy in exhaust losses prediction and turbine group efficiency variations at part load operation.
Transients related to start up of steam turbine are considered as a delay in power production imposing a linear load ramp with different durations for hot and cold start-up (a cold start-up occurs after a stop longer than 24 hours). A fixed power consumption due to the necessity of keeping the turbine in slow rotation and avoid shaft bowing is taken into account after the shut-down of the power block.

5. Solar field and heat storage management

Yearly hour by hour simulations are performed using E-link add-in component for Excel that allows to create a link between TF21 and Excel: a VBA code is developed to handle information exchange from one software to the other and to set down the management of solar field and thermal storage system.
In order to exploit solar energy with high efficiency it is crucial to operate the power block close to its design conditions, keeping HTF mass flow and maximum temperature almost constant. The use of a thermal storage combined with a solar multiple greater than one gives the possibility to satisfy this purpose and permits to cover the request of hot HTF during low irradiation periods. An hour by hour management of the storage system could incur in an unfeasible operation of the power block during those days with low irradiation or intermittent clouds transit. To avoid discontinuous power production and guarantee an almost constant power block load during the day a minimum number of non-stop production hours is considered as power block constraint. On the other hand during high irradiation days defocusing of solar field could be limited increasing HTF mass flow sent to the power block, thus considering a certain level of overload of the steam turbine (12% in our hypothesis). Following these guidelines a VBA code is implemented assuming a daily weather forecast capability, instead of an hour by hour far-sightedness. Heat storage management is optimized as a function of the available daily direct normal radiation to avoid concentrator defocusing if possible, and to limit part load operation, start-up and shut down during a day.
A graphical view of the previously described control strategy applied to a winter and summer day is reported in Figure 3.

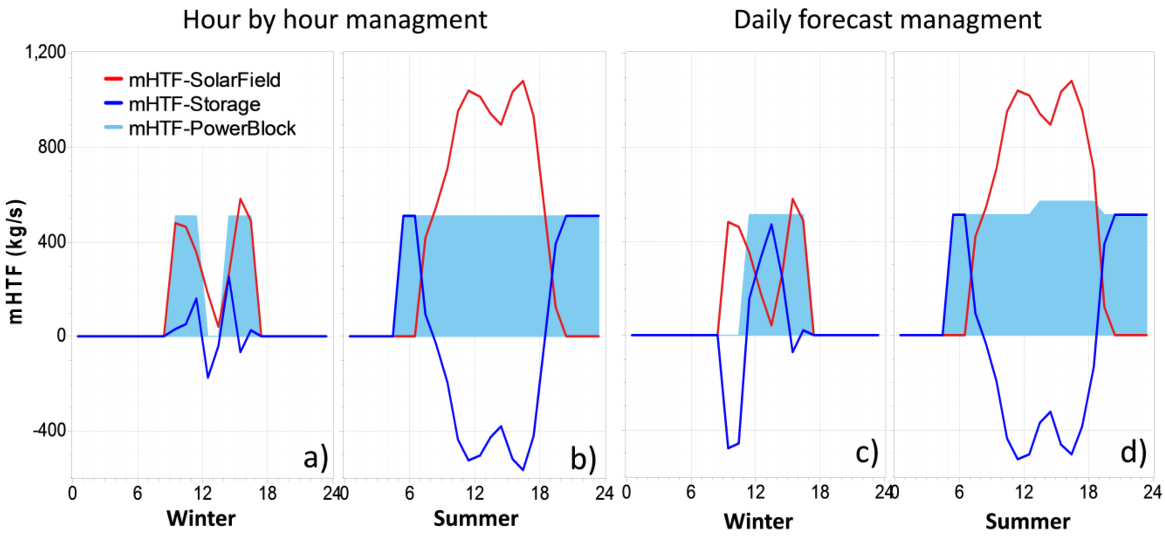

Figure 3. Hour by hour and Daily forecast management code applied to a winter (a, c) and a summer day (b, d).

Red line represents HTF mass flow circulating in the solar field, whereas the blue one corresponds to the synthetic oil mass flow in the heat exchangers of the storage section. Negative values mean HTF flows sent to the thermal storage system while positive ones represent flows sent to the power block during the discharge operation of the heat storage. Light blue filled area corresponds to the net HTF mass flow sent to the power block, whose nominal value is equal to 510 kg/s. It is worth to note that during the winter day with a daily forecast management (c) power block start up is delayed with respect to the solar field and, in the first hours, heat is stored to be available during the day. In this way a continuous operation of the power block is made possible in contrast to an hour by hour management (a) that can bring to a discontinuous or even non feasible operation of the power block. During summer days defocusing of the solar field is delayed (d) as a results of a 12% power block overload respect to the basic management (b) with advantages in terms of collected heat in the solar field and electricity production.

6. Economic analysis

The comparison of solar plants for different location and solar multiple was performed adopting the levelized cost of electricity (LCOE) as term of comparison. The LCOE takes into account total capital cost of the plant and operating costs, and it is calculated by varying the kWh sell price to exactly balance the costs of the power plant over the whole life time. Plant lifetime is assumed to be 30 years with a discount rate of 8%. Total capital costs are calculated as total direct plant costs (which include equipment and installation costs), indirect costs, contingencies and owner's cost [12]. Operating costs, labour, maintenance and insurance were considered as a percentage of the total capital cost. Finally, water make-up costs for steam cycle blow-down as well as evaporative tower were taken into account. Some assumptions for the economic assessment are summarized in Table 4 while the share-out of total plant costs for the reference plant is represented in Figure 4.

Balance of plant	40	%
Indirect costs	14	%
Contingencies and owner's costs	15	%
Labour and maintenance costs	1.5	%
Insurance	0.5	%
Process water make-up	2	€ m^{-3}
Evaporative tower make-up	0.65	€ m^{-3}

Table 4. Economic assumptions.

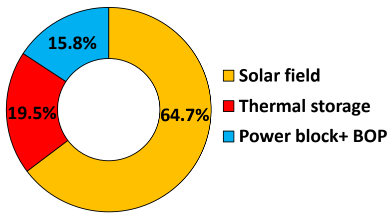

Figure 4. Reference case total plant cost share-out.

7. Yearly results

A parametric study on both SM and storage size is set up with the purpose of finding the best economic solution characterized by the lowest LCOE, obtained from the calculated yearly net electricity produced [GWh] and the total plant investment costs.

A first analysis is carried out for the three different sites adopting different thermal storage sizes and a fixed value for the solar multiple (SM=2). Results are reported in Table 5 and LCOE final results are displayed in Figure 5.

	SEVILLA (Spain)			LAS VEGAS (USA)			DARWIN (Australia)		
EDNI [kWh m^{-2}]	1677.7			2076.7			1719.6		
$EDNI_{max}$ [W m^{-2}]	887.3			1006.2			967.9		
Storage size [h_{eq}]	6	7	8	6	7	8	4	5	6
Effective Sol. En. [GWh]	854.3	854.3	854.3	1057.5	1057.5	1057.5	875.6	875.6	875.6
HTF thermal En. [GWh]	461.8	474.8	484.6	556.2	571.2	585.4	483.22	501.6	510.9
Net electric En. [GWh]	**161.6**	**166.2**	**169.6**	**196.2**	**201.9**	**206.5**	**165.6**	**172.6**	**175.8**
El. Efficiency[(1)] [%]	18.92	19.45	19.85	18.55	19.09	19.53	18.91	19.71	20.08
Defocusing [GWh]	**27.0**	**16.8**	**8.9**	**54.9**	**42.7**	**31.9**	**28.6**	**13.7**	**6.5**
Total plant cost variation [%]	**96.8**	**98.7**	**100.6**	**96.8**	**98.7**	**100.6**	**92.9**	**94.9**	**96.8**

(1) Calculated with respect to effective solar energy (EDNI)

Table 5. Heat storage size sensitivity analysis results for Sevilla, Las Vegas and Darwin.

Comparing efficiency results of the investigated technologies we can observe that Las Vegas, even though it has the highest electricity production, shows the lowest global efficiency because of the huge effective available solar energy during summer, that yields a performance reduction. In addition, it is important to note that in Las Vegas for all the selected heat storage sizes a high amount of defocused energy is obtained as a result of an under-design of the storage system capacity. LCOE curve for this location site (Figure 5) doesn't show a minimum that probably could be reached for highest equivalent hours (h_{eq}). Flat trend of Las Vegas LCOE curve let suppose that the optimum LCOE value is close to the value obtained for a 8 h_{eq} heat storage capacity. On the contrary Darwin shows the highest global efficiency, although its annual solar energy has a value comparable to Sevilla. The reasons of this result can be partly justified with the more favourable geographical location (little effects of IAM correction due to lower average incident angles during the year) and partly considering the almost flat monthly average DNI trend that allows a more homogeneous use of heat storage both in winter and summer days. As a result Darwin shows a greater electricity production and a higher total efficiency with respect to Sevilla and a little percentage of annual defocusing energy. Darwin highest average wet bulb temperature comports a reduction of power block efficiency compared to the other sites but this effect doesn't seem to compromise the total power plant performance.

Total costs are quite similar for all the considered plants with values in a range between 92.9% and 100.6% with respect to the reference plant (Sevilla 7.7 h_{eq}). This little variability is explained observing the share-out of total costs between the three main components: solar field contributes to around an half of the total cost and it is the same absolute value for all the studied solutions, power block cost is almost constant and so total plant cost differences are ascribable only to heat storage component with a relatively low impact on whole plant cost.

Observing LCOE curves displayed in Figure 5 best results are reached for Las Vegas location site with high storage capacity due to the necessity to limit defocusing during summer days as abovementioned. Sevilla is the less attractive site because of the lowest annual solar energy and the necessity to adopt a big thermal storage system. Finally Darwin presents an intermediate trend with the peculiarity of the smallest optimum heat storage size (5 h_{eq} compared to 7.7 h_{eq} for Sevilla and 8 h_{eq} for Las Vegas), due to the almost homogeneous behaviour of effective solar energy during the year that allows to avoid overdesign of the thermal storage.

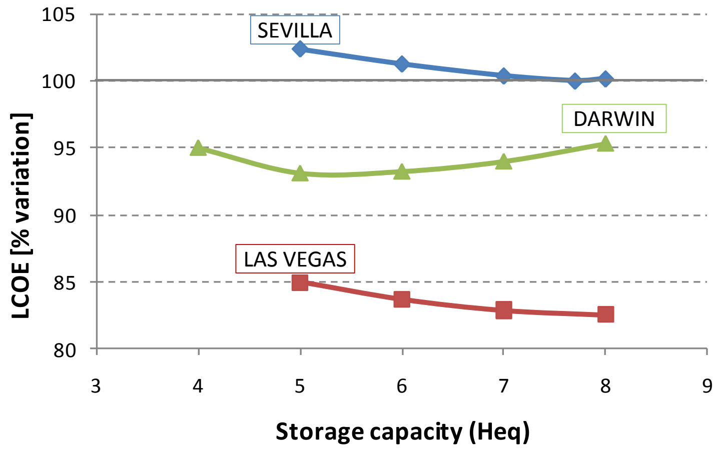

Figure 5. LCOE relative variation with respect to the reference plant for three different solar plant location designed for SM=2.

A second study is carried out for three different SM (1.5, 2, 2.5) and different thermal storage size in Sevilla. Results are reported in Figure 6.

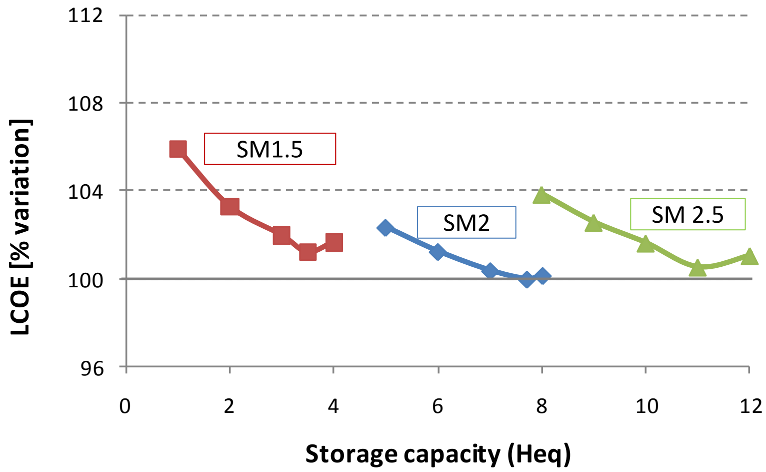

Figure 6. LCOE relative variation with respect to the reference plant for different SM and storage size in Seville site.

LCOE curves show a minimum for all the considered SM and optimal heat storage capacity is found as a result of a trade-off between plant cost increasing and advantages related to defocusing limitation. It is possible to notice how the three optimal LCOE values are similar but the quite sharp trends suggest that for a fixed SM the heat storage size has to be carefully designed. As expected, the reference plant storage size (7.7 equivalent hours) results to be the best solution for this location.

8. Conclusions

This paper discusses the LCOE optimization for a mid-size parabolic trough plant, obtained through the adoption of a proper sizing of the heat storage system. The considered plant technology is based on synthetic oil as HTF in the solar field and a two-tank indirect molten salts thermal storage system. Three geographical locations have been considered, with different latitudes and direct solar radiation. The operating management of the storage system during each hour has been optimized on the basis of a daily forecast, in order to maximize the electricity production. Analyses conducted at a fixed value of SM show that locations at higher latitudes in general results in a greater sizing of the storage tanks, independently of the value of annual solar radiation, because of seasonal effects. Among the considered sites, the optimum heat storage capacity variation is in the range of 3 equivalent hours, while LCOE differences with respect to the reference plant are in the range of 20%. Finally for a chosen location, both SM and storage size have been varied, showing that for each site the minimum value of LCOE is found at a specific combination of them.

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