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Comparison of Parabolic Troughs and Solar Photovoltaic as Solar Field Technology in Dispatchable Solar Power Plants

A Competitiveness Assessment

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Abstract. The use of thermal energy storage (TES) technologies, as means to provide dispatchability to thermally driven solar power production, has long stood as the main argument for the interest and potential competitiveness of Concentrated Solar Power (CSP) when compared to other non-dispatchable alternatives. Whereas reductions of the Levelized Cost of Electricity (LCOE) are observed for CSP in recent years, the notable LCOE reduction observed along this decade in large-scale solar photovoltaics (PV) plants is set to break the taboo of "power-to-heat-to-power" approaches, as its potential economic performance outcasts the associated thermodynamic inefficiency. The possibility of using available resistive heating technologies and components in PV-TES combinations, renders the configuration of a conventional CSP plant suitable for the replacement of a thermal conversion solar field by a photovoltaic field presenting further the possibility of delocalization and/or spatial distribution of the solar field (e.g. on a Carnot Battery configuration). As dispatchability no longer stands as an exclusive argument in favor of CSP over PV, the present article addresses the boundary conditions for the competitiveness of each technology as the champion of dispatchable solar power fields. The impact of both land and electrical heater costs variation in the variation of LCOE for PV-TES plants is much more modest than that observed for the impact of CSP solar field cost variations in the variation of LCOE for CSP plants, which leans for the latter and at present costs, towards better competitiveness for plant designs with a storage capacity in excess of 10.0 FLH (for GHI values in excess of 2100-2200 $kWh \cdot m^{-2} \cdot year^{-1}$).

Keywords: CSP Competitiveness, Carnot Battery, Cost Reduction

1 Introduction

The notable cost reduction observed along this decade in solar photovoltaic (PV) is set to break the taboo of "power-to-heat-to-power" approaches as its potential economic performance compensates the associated thermodynamic inefficiency when compared to the common solar thermal conversion driven by the Concentrated Solar Power (CSP) approach. The possibility of using available "off the shelf" resistive heating components in conventional thermal storage systems, alongside with the increasing interest in the development of other electrical heating solutions for Molten Salts - inductive heating, microwaves - enables the substitution of the solar thermal concentrators field of a conventional CSP plant by a PV field, presenting further the possibility of delocalization and/or spatial distribution of the solar field [1].

Though CSP/PV hybridizations are already in place in commercial plants (operating or under construction), with ratios of PV/CSP installed power ranging from 0.36 (Noor Energy 1 - UAE) up to 9 (in China) [2]), the present article addresses the boundary conditions for the competitiveness of each technology as the champion of dispatchable solar power fields when different aspects of their use are considered: land occupation requirements, technology cost potentials, use of the available solar resource.

Based on a conventional MS-TES/ Rankine Power Block tandem, two different solar field approaches have been compared (by contrast with other publications [2,3]): Parabolic Trough using molten salts as Heat Transfer Fluid (HTF) and PV solar field with resistive heating as the "power-to-heat" conversion unit. Utility-scale power plants with a 100 MW_e grid connection point have been used as the reference for plant dimensioning.

2 Technical assessment

The technical assessment is based on the annual performance of both plant configurations simulated under different sizing parameters (solar multiple – SM, and equivalent full load hours of thermal energy storage – FLH) and locations. Simulations were performed in TRNSYS 17 (see Underlying and related material section) with hourly resolution, backed by Python routines for parametric evaluation. Meteorological data was taken from the TRNSYS weather database of Meteonorm files [4]. The simulations consider two basic models: a system with a Molten Salts Parabolic Trough Power Plant (PTPP) and a Photovoltaic Thermal Storage Power Plant (PVTS), as illustrated in Figure 1.

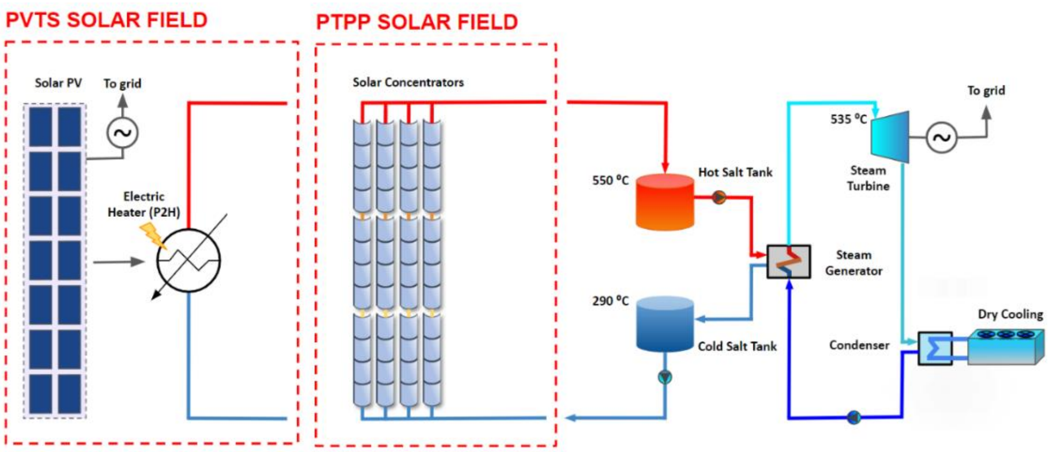


Figure 1. *Schematic configuration of a Parabolic Trough Power Plant (PTPP) and a Photovoltaic Thermal Storage Power Plant (PVTS).*

For the economic assessment, updated Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) costs breakdown have been used for each system configuration.

2.1 System modeling approach

The PTPP simulation is based on a parabolic trough solar field using molten salts as HTF and withstanding a maximum operating temperature of 550 ºC. The thermal storage system is based on a two-tank concept. The plant comprises a power cycle (0.428 efficiency and 10% parasitic losses [5]) with a dry cooling system.

The PVTS simulation is based on a PV field with a single-axis tracking system, chosen in view of its competitiveness and share of newly installed capacity [6], whose production can be directed to the electricity grid and/or used to drive an electrical heater charging the TES system. A similar two-tank TES concept, power cycle, and cooling system are used in both models, as illustrated in Figure 1.

For both cases, the electric output (net) of the power plant is restricted to 100 MW_e. The plant dispatch control provides a steady output (as long as enough energy is available), that is either originated from the solar field (using the remaining energy to charge the TES system) or from the previously stored energy in the 2-tank system. Any excess power generated from the solar field that cannot be delivered to the power block (PTPP solar field), to the grid (PVTS Solar Field) or to the storage system is wasted (e.g., defocusing the solar field).

Aiming at the identification of the impact of solar field and thermal storage dimensioning over the technical (yield) and economic (LCOE) performance of each plant on different locations, simulations have been performed, for both plants, under the following parametric variations:

- solar field dimensioned for SM in the range of 1 to 7, with steps of 0.5,
- thermal storage dimensioned for FLH in the range of 3 to 17, with steps of 1,

thus, standing for 13 x 15 (195) annual simulations per plant and location.

2.2 Cost model

Aiming at an optimal dimensioning assessment for both systems in different locations, the cost model adopted in this work follows the structure proposed by Hirsch et al. [7] for utility-scale solar thermal power plants:

- CAPEX and OPEX are separated into Engineering, Procurement, and Construction (EPC) direct and indirect costs;
- CAPEX stands for the sum of EPC direct and indirect costs and Owner's cost [7];
- EPC direct and indirect costs are gathered from the literature [5–13], and the accumulated inflation corrected the monetary values up to 2021.

The component breakdown of EPC direct costs used for the different subsystems of both plant configurations is presented in Table 1 in terms of specific cost.

Table 1. *Component breakdown of EPC direct costs of PTPP and PVTS systems.*

PTPP	PVTS	Component	Value	Unit*	Ref.
x	x	Site Improvements	26.96**	USD/m^2_{mirror}	[5,7–11]
x		Solar Field	161.79	USD/m^2_{mirror}	[5,7–11]
	x	1-axis PV solar field	1000.0	USD/kW_e	[6,13]
	x	Electrical heating	104.7	USD/kW_e	[12]
x	x	TES	28.16	USD/kWh_{th}	[5,7–11]
x	x	BOP***	288.75	USD/kW_e	[5,7–11]
x	x	Power Block***	1121.72	USD/kW_e	[5,7–11]

*USD means United States Dollars – values consider the accumulated inflation up to 2021 (USD = USD^{2021}). **Such a value already accounts for the land factor, i.e., the relation between the solar field aperture area and the correspondent land area needed for the power plant. As an example, Hirsch et al. [7, pp. 9] have considered a land factor of 4 and a Site Improvements cost of USD ^{2017} 4/m^2_{land} – which corresponds to a compound cost of USD 16.89/m^2. ***Based on steam turbine gross power.

The EPC indirect costs of both power plant cases are shown in Table 2. It comprises EPC services, Profit margin and Contingencies, Owner's costs, and the Operation and

Maintenance (O&M) costs that constitute the OPEX. CAPEX and OPEX results for different SM (Solar Multiple) and FLH (Full Load Hours), based on this cost model, are presented in Figure 2a. As for macroeconomic assumptions, a 25 year lifetime was considered, with a discount rate of 7.0% and an inflation rate of 4.0% (over OPEX costs and revenue), as well as a degradation rate of 0.4%/year [14,15].

***Table 2**. EPC Indirect costs, Owner's costs, and O&M costs.*

EPC Indirect costs	**Value**	**Unit**	**Ref.**
EPC services	5.0	% of EPC direct costs	[7,11]
Profit Margin and Contingencies	10.0	% of EPC direct costs	[11]
Owner's costs	**Value**	**Unit**	**Ref.**
Project development	10.0	% of EPC (direct and indirect) costs	[11]
Additional Owner's cost	3.0	% of EPC (direct and indirect) costs	[7,11]
Land cost	1.14	USD/m^2 of land area	[11]
Infrastructure*	6.86×10^6	USD (fixed cost)	[7,11]
O&M costs	**Value**	**Unit**	**Ref.**
PTPP	2.2	% of CAPEX	[11]
PVTS	13.0	USD/kW$_e$	[6]

*High voltage grid connection, backup power supply grid connection, water connection, fuel connection, access road – project-specific cost, depending on constraints.

2.3 Selected locations

Since concentrating thermal collectors use only Direct Normal Irradiation (DNI), in contrast with non-concentrated photovoltaics that use Global Direct Irradiation (GHI), the selection of locations for this study followed different irradiation levels and ratios of annual GHI and DNI. This approach enables the evaluation of the impact of DNI/GHI ratios on the competitiveness of both PTPP and PVTS systems.

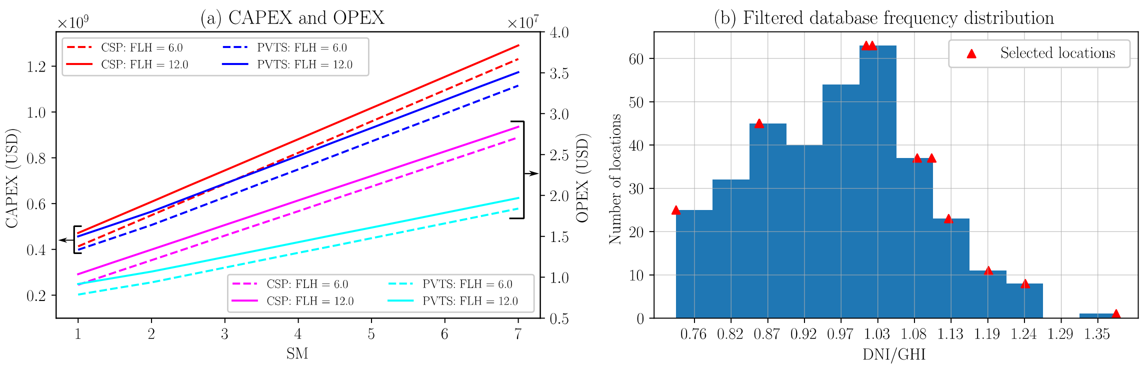
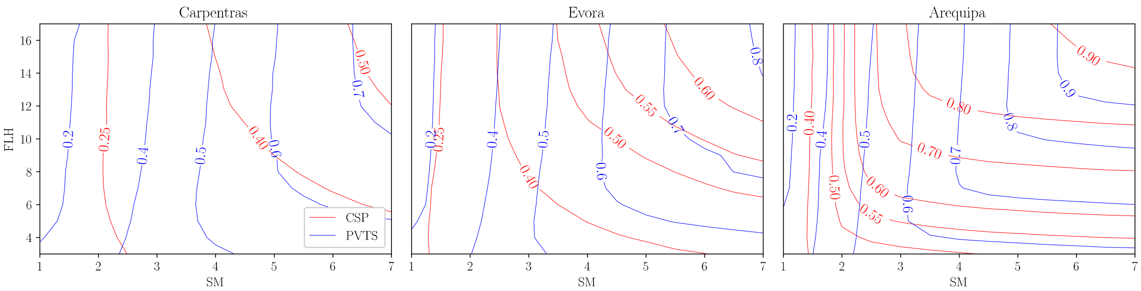


***Figure 2**. PTPP and PVTS plant simulations: (a) CAPEX and OPEX costs, (b) TRNSYS weather filtered database frequency distribution of the DNI/GHI ratio and indication of selected locations.*

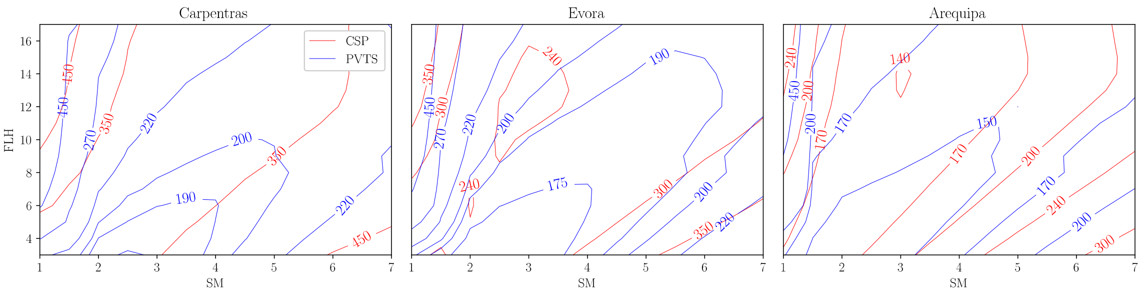
Whereas TRNSYS database comprises roughly 1000 locations, a constraint regarding levels of irradiation – 1500 kWh·m^{-2}·year^{-1} ≤ DNI and GHI ≤ 3700 kWh·m^{-2}·year^{-1} – reduces the database to 339 possible locations, so that the frequency distribution of ratio of annual GNI and DNI is shown in Figure 2b. Within this filtered database, 11 locations have been selected for this assessment, upon their ratio of annual GNI and DNI, as presented in Figure 2b: Andir (China, GHI: 1904.7, DNI: 2062.7), Arequipa (Peru, 2474.5, 2796.8), Carnarvon (Australia, 2268.2, 2508.3), Carpentras (France, 1500.1, 1516.7), Djibouti (Djibouti, 2191.7, 1877.4), Evora (Portugal, 1758.5, 1907.5), Hailar (China, 1610.1, 2209.1), Kathmandu (Nepal, 1846.7, 1883.5), Korhogo (Ivory Coast, 2068.4, 1522.6), Lethbridge (Canada, 1509.0, 1872.8), Maputo (Mozambique, 1783.8, 1527.3) – where GHI and DNI are given in units of kWh·m^{-2}·year^{-1}.

3 LCOE and Capacity factor results

Technical and economic assessment results, expressed in terms of Capacity Factor (CF) and Levelized Cost of Electricity (LCOE), have been obtained for each of the technological, dimensioning and location options presented in Section 2. To exemplify results for both CF and LCOE for different dimensioning criteria, Figure 3 shows data for three (out of eleven) different locations: Carpentras, Évora, and Arequipa.



(a)



(b)

Figure 3. *Technical economic assessment results for different plant dimensioning parameters in Carpentras (France), Evora (Portugal) and Arequipa (Peru): (a) CF and (b) LCOE (USD/MWh).*

The LCOE results herein presented stand for the critical electricity selling price assuring the viability of the investment under the cost and macroeconomic assumptions presented in Section 2. Optimal dimensioning of each plant, for a given location, stands thus for the SM/FLH combination assuring the lowest LCOE result.

As for CF results, it is important to refer that, in view of the similarity of both technological options – PTPP and PVTS – in terms of their dispatchability features:

- the differentiation of electricity selling values in different time periods would likely affect both technological options in a similar way;
- the cost of the interconnection point is included likewise in both models, so that in both cases higher CF results stand for a lower impact of the interconnection and power block costs in CAPEX and LCOE.

4 Competitiveness assessment

Taking into consideration the impact of both solar resource and storage capacity, expressed for both technological options in terms of GHI and FLH in the competitiveness of each plant in different locations, expressed in terms of the lowest LCOE achieved for different values of SM (optimal plant dimensioning), results of LCOE for different GHI levels are presented, for different storage capacities, in Figure 3.

With focus on the solar field related competitiveness aspects pertaining each technological option (PTPP and PVTS), each LCOE result obtained for the selected locations is complemented with a LCOE variation bar standing for the variation of land (-100% to +100%), PTPP solar field (-30% to +0%) and PVTS electrical heater costs (-50% to +50%). Whereas higher DNI/GHI ratios tend to improve the LCOE results, more notably in the case of the PTPP plant in view of its DNI performance dependence, a LCOE(GHI) function is achieved, for each FLH, after a second-degree polynomial regression to the LCOE results obtained for different GHI levels. Applying the same approach to the maximum (LCOE+) and minimum (LCOE-) values obtained upon the parametric variations of land, solar concentrator field and electrical heater costs, a LCOE±(GHI) band is obtained.

The graphics presented in Figure 4 illustrate the application of this approach to the optimal plant dimensioning results obtained for 10.0 FLH, where the impact of cost variations and DNI/GHI ratios can be observed, as well as the LCOE(GHI) curves and LCOE±(GHI) bands for three different FLH.

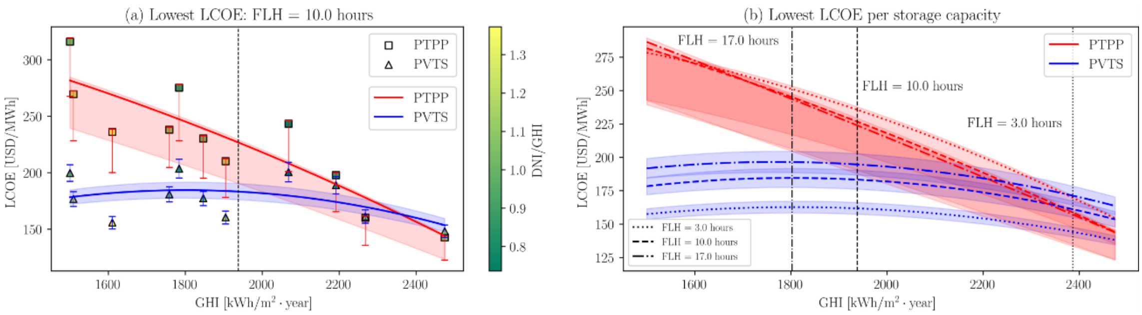


***Figure 4**. PTPP x PVTS competitiveness assessment: (a) variation of LCOE as a function of the base value cost variations for land (-100% to +100%), PTPP solar field (-30% to +0%) and PVTS heater (-50% to +50%), LCOE(GHI) curve and LCOE(GHI) band for FLH=10.0 and (b) LCOE(GHI) curve and LCOE(GHI) band for FLH=[3.0, 10.0, 17.0]. The vertical line in figures (a) and (b) refers to the GHI value at which the upper boundary of PVTS cost assumptions yields the same LCOE as the lower boundary of PTPP cost assumptions.*

An assessment of competitiveness in terms of PTPP solar field costs alone (i.e., keeping land and electric heater costs in their base values) is presented in Figure 5 in terms of a PTPP solar field CAPEX factor: a multiplying factor over solar field CAPEX rendering similar LCOE results for both PTPP and PVTS plants (e.g. a factor of 0.7 stands for the need of a 30% PTPP solar field cost reduction; a factor of 1.0 stands for similar competitiveness).

5 Conclusions

The work herein aims to assess the competitiveness of conventional CSP plants (PTPP) with an optional PV-based solar field configuration (PVTS). The results obtained for both CF and LCOE under various plant dimensioning and solar resource conditions show that, despite the significant cost reductions attained by PV technologies, conventional CSP plants are still competitive given adequate solar resource and storage capacity conditions.

Notwithstanding the need for a specific location based assessment - as the DNI/GHI ratio impact over LCOE results shows - it is possible to observe in both the LCOE(GHI) and LCOE±(GHI) results presented in Figure 4 that:

- the impact of both land (-100% to +100%) and electrical heater (-50% to +50%) costs variation in the variation of LCOE for PVTS plants is much more modest than that observed for the impact of PTPP solar field cost variations (-30% to +0%) in the variation of LCOE for PTPP plants (thus the PTPP advantage on land use - minus 30% land area than PVTS, namely 1.62 vs 2.3 ha/MW_e per SM, respectively - does not show to be critical in terms of LCOE);

- as expected, the impact of DNI/GHI ratio on LCOE is higher in PTPP plants than in PVTS plants, in view of the DNI dependence of solar concentrators performance, where PTPP plants tends to be more competitive than PVTS plants for DNI/GHI ratios higher than 1.1 (for GHI levels above 2100-2200 kWh·m^{-2}·$year^{-1}$);
- the thermodynamic inefficiency of the PVTS technological approach, derived from the lower solar-to-heat conversion efficiency in the solar field, is apparent in the competitiveness threshold of PTPP plants, achieved for lower GHI values upon increased FLH designs, where a larger proportion of the energy produced in the solar field is delivered to the TES / power block subsystem;
- unless solar field cost reductions are achieved, the PTPP competitiveness threshold leans, at present costs, towards plant designs with a storage capacity in excess of 10.0 FLH (for GHI values in excess of 2100-2200 kWh·m^{-2}·$year^{-1}$).

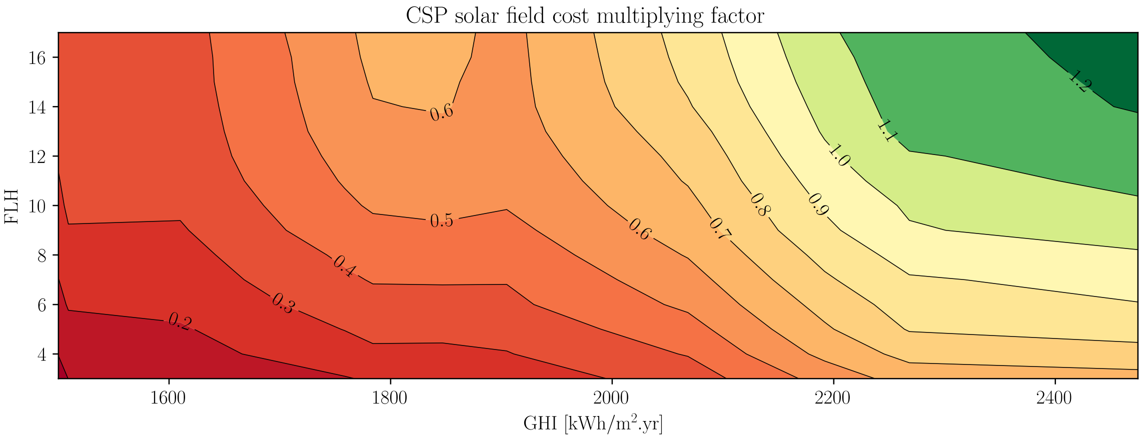


***Figure 5**. PTPP solar field CAPEX factor for competitiveness conditions with PVTS plants for different GHI levels and FLH.*

Data availability statement

All the data supporting the results of this article is available in the indicated references.

Underlying and related material

TRNSYS models to perform an annual simulation (with hourly timesteps) for PTPP and PVTS systems, as well as a Readme file, are in Zenodo: https://doi.org/10.5281/zenodo.8289172.

Author contributions

Conceptualization: PH, TE, AS, RC, LF. **Data curation**: TE, AS, LF. **Formal Analysis**: PH, TE, AS, RC, LF. **Funding acquisition**: PH, RC, LF. **Methodology**: PH, TE, RC. **Software**: TE, AS. **Supervision**: PH. **Visualization**: PH, TE, AS. **Writing – original draft**: PH, TE, AS. **Writing – review & editing**: PH, TE, AS, RC, LF.

Competing interests

The authors declare that they have no competing interests.

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