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Review on the economic impacts of solar thermal power plants

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ABSTRACT

A systematic literature review on the economic performance of solar thermal power plants including integrated solar combined cycle (ISCC) plants was conducted. A number of solar thermal technologies like parabolic trough (PT), solar tower (ST), linear Fresnel reflector (LFR) and solar dish (SD) were evaluated. The evaluation revealed that solar tower plants typically had the highest capital costs, followed by parabolic-trough and linear Fresnel plants. The results of the studies showed that at smaller capacities of 10–50 MW, PT plants achieved lower LCOE than ST plants, while at larger capacities of 100 MW and above, ST tend to have lower LCOE than PT. There was limited comparative studies on the economic performance of LFR and SD plants. Hence, future studies should focus on the economic impact of different solar thermal technologies including LFR and SD of various capacities using homogeneous modelling conditions. The economic performance of direct steam generation (DSG)-ISCC plants was compared to ISCC, combined cycle gas turbine (CCGT) and conventional solar thermal plants and the results showed that DSG-ISCC plants achieved the lowest LCOE values. Studies also showed that in general, hybrid plants achieved lower LCOE than standalone solar thermal plants. LCOE and capital costs were the dominant financial metrics used in the literature, with very few studies using total life cycle cost, revenues, payback time and internal rate of return. Future studies should include these metrics in order to provide a comprehensive financial assessment of solar thermal power plants, enabling their economic performance to be compared with other renewable and non-renewable energy systems.

1. Introduction

The rise in population growth, industrialisation and urbanization has increased energy demand across the world. Most of the energy used is still fossil-fuel based which releases greenhouses gases into the atmosphere, resulting in global warming and climate change. There is a need to displace fossil-fuel source of energy with renewables that are much cleaner and better for the environment. The benefits of using renewable energy includes increased energy security and reduced exposure to market volatility. a The European Union has set a target to reduce greenhouse gas (GHG) emissions by at least 55 % by 2030, compared to 1990 levels and 80 % by 2050 [1]. The industrial sector which is the third largest energy consumer in Europe must depart from fossil-fuel based energy and implement more renewable energy technologies in order to achieve the EU's GHG emissions reduction target [2]. Renewable energy technologies such as solar thermal power plants can be used to replace fossil-fuel plants, thereby significantly reducing their environmental and human health impact. The use of solar thermal technologies to generate electricity and thermal energy for process heating and cooling can contribute to the decarbonisation of the European industrial sector. The four main solar thermal power technologies are parabolic-trough, solar tower, linear Fresnel and solar dish plants. One of the main advantages of these technologies is the ability to incorporate thermal energy storage (TES) to enable dispatchable heat or electricity generation even at times of little or no solar radiation [3]. However, one of the main aspects is the assessment of the economic feasibility of solar thermal plants to enable investors, policy makers and stakeholders to compare the economic impact of different energy sources and make well-informed investment decisions. The economic assessment of a solar thermal plant covers its whole life cycle from raw materials extraction, manufacturing of components, construction of the plant, operation, maintenance and its end of life disposal costs. A wide range of indexes can be used to analysis the economic performance of a plant such as the capital costs, levelized cost of energy (LCOE), life cycle costs (LCC), net present value (NPV), benefit-cost ratio (BCR), internal rate of return (IRR), payback period and revenues. This paper will

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review and compare the economic performance of the four main types of solar thermal technologies, integrated solar combined cycle plants and hybrid solar thermal plants. It will also identify knowledge gaps and areas for further research in the economic assessment of solar thermal power plants.

1.1. Objectives

This paper reviews studies conducted on the economic assessment of different types of solar thermal power plants, including solar thermal plants hybridized with renewable energy sources as well as integrated solar combined cycle plants with capacities above 250 MW. It also identifies the gaps in the economic assessment of solar thermal power plants that future studies should focus on, in order to provide a comprehensive financial evaluation of these plants, enabling their economic performance to be compared with other renewable and non-renewable energy systems. A number of studies have reviewed solar thermal technologies including solar thermal plants hybridized with renewable energy sources but have focussed mainly on their technical performance [64,66,68,69,83]. This review paper is the first of its kind to focus on the economic performance of a wide range of solar thermal technologies including hybridized plants, integrated solar combined cycle systems and conventional solar thermal power plants. Historical and future development in solar thermal technology are also presented and discussed. Furthermore, recommendations for the research community working on the technical–economic aspects of solar thermal power plants are provided.

1.2. Historical development in solar thermal technology

The first commercial solar thermal power plants were pioneered by Luz International Limited between 1984 and 1991 in the Mojave Desert, California. These Solar Electric Generating Station (SEGS) plants consisted of nine solar thermal power plants using parabolic trough technology with a combined capacity of 354 MW [63]. However, the regulatory initiative that supported the progress of solar thermal power plants disintegrated due to the significant reduction in oil price at the time. In 2006, solar thermal power plant initiatives were established in Spain and in the USA. The solar power generation policies were amended in these countries and feed-in tariffs were introduced in Spain [64]. The California Energy Commission approved licences for five solar thermal power plants with combined installed capacity of 2284 MW in March 2014. The aggregated installed capacity of solar thermal power plants in Europe reached 5GW in 2015. Between 2016 and 2022, there were fifteen additional solar thermal power plants in operation and seven plants in construction in countries around the world [65]. According to SolarPACES, there are currently a total of 114 solar thermal power plants in operation, 12 under construction and 20 decommissioned or non-operational across the world [65]. The development of CSP plants around the world has increased with a total of 6,128 MW CSP plants in operation, 1592 MW plants in the development phase and 1547 MW plants under construction. Spain has the largest CSP capacity of 2304 MW globally, followed by the USA at 1740 MW [66]. It is estimated that 83GW could be installed through solar thermal power plants by 2030, reaching 342GW by 2050 with the highest proportion forecasted to come from the Middle East, followed by Northern Africa and then European countries [67]. In the future, electricity may be exported from solar thermal power plants generated in the desert regions of the Middle East and North Africa (MENA) to Europe. It has been found that the electricity demand of all Europe can be achieved by harvesting from only 0.4 % of the Sahara Desert, thereby using only 2 % of the earth's total land surface for global electricity demand to be met [64].

Solar thermal technologies can be integrated with combined cycle gas turbines resulting in an integrated solar combined cycle plant. The concept of integrated solar combined cycle (ISCCC) began in the 1990 s and is an effective way to utilize the efficient combined cycle technology with the benefits of renewable solar energy. The efficiency of ISCC plants is typically well over 50 % and has become a popular choice for new power plants due to its low cost, high efficiency and relatively low emissions resulting from the use of natural gas as a low carbon fuel [68]. Solar thermal power plants can also be hybridized with renewable energy sources such as PV, wind, biomass and geothermal. The first operating commercial hybrid CSP-biomass plant was the Termosolar Borges in 2012 with a capacity of 22.5 MW and located in Spain [69]. However, both lower and higher capacity hybrid CSP-biomass plants up to 50 MW are currently in operation [81,82]. The first hybrid CSP-geothermal plant was the Stillwater triple hybrid power plant in Nevada, USA with a capacity of 33.1 MW and commissioned in 2009 [69]. The Solgest-1 is the first hybrid CSP-PV plant with a capacity of 110 MW and TES of more than 6 h, while the PV section has an installed power of 40 MW. The hybrid CSP-PV plant which uses PT technology is located in Spain and is able to generate electricity 24 h a day [70]. Wind power generation technology is very different from solar thermal technology, therefore opportunities to hybridize CSP with wind are less prevalent in the literature [68]. However, there's a multi energy complex in China which combines 400 MW wind power, 200 MW PV and 50 MW ST plant to generate 160GWh of electricity per year [63]. The benefits of CSP plants hybridized with renewable energy sources include improved plant efficiency through the synergy of the different energy sources, lower costs compared to standalone solar thermal plants, dispatchability of the hybrid plant through the use of TES and the potential to achieve 100 % environmental sustainability.

1.3. Future development in solar thermal technology

One of the promising technologies is direct steam generation (DSG) that can be applied to solar thermal power plants enabling steam to be produced directly from the solar field and supplied to a power block for electricity production. The advantages of DSG includes simplification of operation, no environmental risk of fire and leakage and reduction in the cost of the solar thermal plant by increasing the temperature of the working fluid over 400 °C which is difficult to achieve with synthetic oil. In addition, operation and maintenance costs are lower for DSG than for synthetic oil systems as there will be no need for an auxiliary heating system [64]. A number of studies have assessed the performance of mainly PT plants integrated with DSG technologies [56,57,58,59], however future studies should focus on the implementation of DSG with other solar thermal technologies such as ST and LFR. Future research should also be directed on improving plant efficiency through various methods such as hybridisation of solar thermal power plants with renewable energy sources with the inclusion of DSG technology. Prospective development in solar thermal power plant includes the integration of nanoparticles in the base fluid to enhance its thermophysical properties. Commonly used base fluids like water, ethylene glycol and thermion have low thermal conductivity and lower heat transfer rates which can be increased with the inclusion of nanoparticle suspension (1–100 nm) in them [66]. In addition, future development includes research on storage of thermochemical energy in solar thermal power plants and novel ISCC systems including the direct steam generation-integrated solar combined cycle-evacuated tube (DSG-ISCC-ET) system that has demonstrated superior thermo-economic performance than combined cycle gas turbine (CCGT) and DSG-ISCC plants [66].

2. Literature review methodology

Systematic literature review using Web of Science, Science Direct, Scopus and IEEE Xplore databases was conducted to identify studies that performed economic assessments of solar thermal power plants including integrated solar combined cycle power plants and hybrid solar thermal plants. Techno-economic, economic assessment, economic performance, concentrating solar power (CSP) plants, solar thermal power plants, integrated solar combined cycle (ISCC), hybrid solar thermal plants were the six central topics used in the searches. The following terms; "techno-economic" OR "life cycle costs" OR "economic assessment" OR "economic performance" OR "economic impact" AND (CSP plants OR solar thermal power plants OR integrated solar combined cycle OR hybrid solar thermal plants OR hybrid CSP plants) were used to retrieve papers in which these terms were found in the title, abstract and/or keywords. The following inclusion criteria were defined to identify relevant papers; articles, proceeding papers, book chapters and the publication dates selected were between 2010 and 2023. The retrieved papers were then carefully reviewed on a case-by-case basis, based on the title and the abstract of each paper. Finally, the papers that were relevant and met the inclusion criteria were selected for detailed analysis.

2.1. Financial metrics for the economic assessments of solar thermal plants

Economic assessment is used to evaluate the financial performance and feasibility of power generation plants. This helps decision makers to choose the best investment plan, on the basis of the least cost of the power plant [4]. It also enables investors and decision-makers to determine the profitability and return on investment of the project. There are different types of metrics used to assess the economic performance of power generation plants. They include the levelized cost of energy (LCOE), net present value (NPV), internal rate of return (IRR), capital costs, life cycle cost, payback time, benefit-cost ratio (BCR) and revenues. The LCOE and NPV are the two metrics commonly used to evaluate the economic feasibility of solar thermal plants, with LCOE being the most popular method used [6,7].

2.1.1. Levelized cost of energy (LCOE)

The levelized cost of energy is the sum of the net present values of all expenditures over the lifetime of a solar thermal plant divided by the total energy generated and is expressed as a cost per unit of electricity generated. It considers the total life cycle cost of a project including pre-development, plant installation costs, operation and maintenance, financing and disposal costs [8]. The LCOE can change from one project to another, depending on the size of project, the location's DNI level, the solar thermal technology, capital and operating costs [3].

2.1.2. Net present value (NPV)

The NPV is used to evaluate the profitability of a project and is the difference between the discounted cash flows (inflow and outflow) of a project during its lifetime. It determines the current value of all future cash flows generated by a project, including the initial capital investment [9].

2.1.3. Capital cost

The capital cost of a solar thermal plant includes the costs of the components of the solar thermal plants, plant installation costs and land costs [10]. Sau et al. [11] reports that the investment or capital cost of a plant is calculated by considering the following elements; land requirement, solar field, heat storage, power block, integration back up heater and civil works. The capital costs of a plant are also dependent on factors such as plant capacity, type of solar thermal technology, thermal storage size and location of the plant [11].

2.1.4. Total life cycle costs (TLCC)

Total life cycle cost quantifies all the costs associated with the lifetime of a project from cradle to grave. It includes predevelopment costs, land costs, component costs, plant installation, civil works, personnel costs, operation & maintenance, plant dismantling & disposal, tax and financing costs. TLCC is a cost management tool which is used to estimate and analyse all the costs accrued throughout the lifetime of a project [13]. It enables decision-makers to evaluate the entire lifespan of a project and plan accordingly, considering the long-term costs and benefits. It also enables resources to be allocated efficiently and avoid unnecessary losses by making well-informed financial decisions [4,5].

2.1.5. Payback period

The payback period is the duration of time required to recover the investment spent on a project or to achieve a break-even point. The payback year is when a cumulative net cash flow turns from a negative to a positive value [14].

2.1.6. Benefit-Cost ratio (BCR)

Benefit-Cost Ratio is used to examine the economic feasibility of a project and to determine whether and to what extent the benefits of a project outweigh its costs. This ratio is calculated as the total present value of benefits divided by the total present value of costs [3]. The BCR has an important impact on the investment decisions of the solar thermal industry [4]. A project with a BCR greater than one is regarded as economically viable while a BCR of less than one means that the costs are greater than the benefits, and therefore the project is not economically feasible [3].

2.1.7. Internal rate of return (IRR)

Internal Rate of Return is used to assess the profitability of projects and is a rate of return for which the NPV of all cash flows from a project is equal to zero. The higher the IRR, the better the profitability of a project [4].

2.1.8. Revenues

Revenues can be obtained from electricity & heat generation incomes and government tax subsidies such as value-added tax (VAT) refunds. Revenues generated from selling heat or electricity on the market can reduce the total plant cost and increase the economic viability of the solar thermal plant [13].

3.0. Investigation on the economic assessment of solar thermal plants

This section presents the different metrics used in the economic assessment of solar thermal power plants. The summary is presented in Tables 1 to 4 of which Table 1 shows studies with economic assessment of solar thermal power plants of 10 MW-50 MW, Table 2 of 100 MW-250 MW and Table 3 of 11 MW-135 MW. Table 4 shows the studies with integrated economic and environmental assessment of the solar thermal power plants. The studies in the literature reviewed used a variety of financial metrics to assess the economic performance of the plants and the frequency of these metrics is depicted in Fig. 1. Parabolic trough (PT), solar tower (ST), linear Fresnel (LFR) and solar dish (SD) are the four solar thermal technologies used in the literature, with their frequencies displayed in Fig. 2. The proportion of software tools used in the studies are illustrated in Fig. 3. It can be seen that LCOE was the most popular financial metric used in most of the studies as displayed in Fig. 1. This could be due to it being the most preferred metric used for the economic performance of power generation technologies as it considers the costs of project installation, electricity generation, and operation and maintenance costs [46]. The capital cost was the next popular metric, followed by the NPV, payback time, IRR and revenues. The least popular metrics were total life cycle costs (TLCC) and benefit-cost ratio.

In terms of the frequency of the different types of solar thermal technologies used in the literature it was found that parabolic trough was the most popular technology used in the studies as depicted in Fig. 2. The next commonly used technology was solar tower, while linear Fresnel and solar dish were the least used technologies in the literature reviewed. This could be due to linear Fresnel being a relatively young technology compared to parabolic and solar tower while solar dish technology is still in its demonstration stage and not yet commercialised [44].

In terms of using techno-economic software for calculating financial

Table 1
Studies with solar thermal power plants of 10 MW-50 MW.

Reference	Shafiee et al. [3]	Islam et al. [14]	Trabelsi et al. [15]	Sultan et al. [6]
Type of solar thermal system	Parabolic trough	Parabolic trough, Solar Tower, Solar Dish	Parabolic Trough	Parabolic Trough
Plant Capacity (MW)	50 MW	10 MW	50 MW	50 MW
Economic Assessment Software	SAM	N/A	N/A	SAM
Economic Assessment Method	LCOE, Total Life Cycle Cost (TLCC), NPV, Benefit-Cost Ratio (BCR), IRR, Discounted payback period (DPBP)	LCOE, NPV, IRR, Discounted Payback Period (DPP), Profitability Index	Total Investment Costs, Annual Revenues, LCOE	LCOE
Economic impact (Internal)	LCOE = $0.16 per kWh TLCC = $ 773,304,457.05 NPV = $64,123,099.54 BCR = 1.15, IRR = 12 % Discounted Payback period = 17.24 years	**Unit cost of electricity/LCOE** PT = 0.77RM/kWh, SPT = 0.83 RM/kWh SPD = 1.95 RM/kWh **Total Capital Cost** PT = €36 million, SPT = €35 million, SPD = €80 million **NPV:** PT = RM 22.52 million, SPT = RM 8.15 million **Discounted Payback (Labuan):** PT = 18.84 yrs, SPT = 24.05 yrs. **IRR:** PT = 12 %, SPT = 11 % **Profitability Index:** PT = 1.13, SPT = 1.05	**Total Investment Costs** Wet-cooled plant = €241.623 million Dry-cooled plant = €251.283 million **Average Annual Revenues** Wet-cooled plant = €13.15 million Dry-cooled plant = €11.88 million **Levelised Cost of Electricity** Wet-cooled plant = 15.97 cent/kWh Dry-cooled plant = 18.28 cent/kWh	Lowest LCOE = 15.0663¢/kWh when SM is 3.3 and TES = 16hrs
Economic Impact (External)	N/A	N/A	N/A	N/A

Reference	Zhao et al. [7]	Parrado et al. [16]	González-Portillo, et al. [17]	Sau et al. [11]	El Boujdaini et al. [18]	Janjai et al. [50]
Type of solar thermal technology	Parabolic Plant	Parabolic Trough	Parabolic Plant & Linear Fresnel Plant	Parabolic Trough Plant	Parabolic Trough	Parabolic Trough, Solar Tower, Solar Dish
Plant Capacity	50 MW	50 MW	50 MW	50 MW	50 MW	10 MW
Economic Assessment Software	Mathematical model	MATLAB & SAM	SAM	N/A	MATLAB	TRNSYS
Economic Assessment method	LCOE	LCOE	LCOE	LCOE	LCOE	LCOE
Economic Impact (Internal)	LCOE = 1.441 Yuan/kWh	Lowest LCOE = $14.07 cents/kWh in 2014 and reduces to $7.35 cents/kWh in 2050.	LCOE (PT) = 0.137€/ kWh	LCOE = 22 cents/kWh for both the binary and ternary molten salt mixtures used as the heat transfer fluids	**LCOE Results** Oujda = 0.25 €/kWh Ouarzazate = 0.18 €/ kWh (Lowest LCOE)	**LCOE Values** PT = $0.30/kWh ST = $0.35/kWh SD = $0.87/kWh
Economic Impact (External)	N/A	N/A	N/A	€12 tons/CO_2 emissions €57.3k/yr when the binary mixture is used as the HTF. €37.7k/yr when the ternary mixture is used as the HTF.	N/A	N/A

Reference	Boukelia et al. [19]	Belgasim et al. [21]	Soomro et al. [22]	Krishnamurthy et al. [12]	Purohit et al. [51]
Type of solar thermal system	Solar Tower	Parabolic Trough	Solar Tower, Parabolic Trough, Linear Fresnel, Solar Dish	Parabolic Trough	Solar Tower, Parabolic Trough, Linear Fresnel, Solar Dish
Plant Capacity	19.9 MW	50 MW	50 MW for ST, PT & LFR plants, 5 MW for SD plant	50 MW	10 MW except for PT @50 MW
Economic Assessment Software	SAM	SAM	SAM	N/A	SAM
Economic Assessment Methods	Capital Cost, LCOE, NPV	LCOE, Total Plant cost	LCOE, Capital Cost	Total Capital Cost, LCOE	LCOE
Economic Impact (Internal)	**Wet Cooling** Capital Cost = $213 million LCOE = $16.87 cent/kWh	LCOE = $24/kWh Total Cost = $412 million	<u>Quetta Location</u> **Capital Costs** PT = $422,455,744, ST = $597,225,600 LFR = $314,223,840	Total Cost = $380 million LCOE = $23 cent/kWh Solar field = 62% of Total cost = 13% of Total Cost TES = 9% of Total cost, Heat	<u>Rasjamand Location</u> **LCOE Values** LFR = 6.85 Rs/kWh PT = 6.98 Rs/kWh

(continued on next page)

Table 1 (*continued*)

Reference	Boukelia et al. [19]	Belgasim et al. [21]	Soomro et al. [22]	Krishnamurthy et al. [12]	Purohit et al. [51]
	NPV = $23.49 million **Dry Cooling** Capital Cost = $209 million LCOE = $15.45 cent/kWh NPV = $22.99 million		SD = $14,620,023 **LCOE Values** PT = 3.69cents/kWh, ST = 10.9cents/kWh LFR = 11.29 cents/kWh SD = $ 3.34 cents/kWh	Exchanger = 3% of costs Civil costs = 2% of costs, Balance of plant = 5%	ST = 7.05 Rs/kWh SD = 8.27 Rs/kWh
Economic Impact (External)	N/A	N/A	N/A	N/A	

metrics such as LCOE, capital cost, NPV, IRR, payback period, revenues and total life cycle cost of renewable energy projects, it was found that SAM was the most popular software used in the studies [46]. Fig. 3 shows similar results which could be due to SAM software being the most preferred as it is a performance and financial model that estimates the cost of energy for power projects based on installation, operating costs and system design of the plant. Other software tools used in the studies were MATLAB, Gabi, TRNSYS, Engineering Equation Solver (EES), Aspen, Excel, SimaPro, Thermoflex + PEACE and numerical equations. Some of the studies did not state the software tool used in the financial assessment of the plants.

3.1. Studies with solar thermal plants of 10 MW-50 MW

This section presents the assessment of solar thermal power plants with capacities of 10 MW-50 MW as shown in Table 1. Amongst the studies in the reviewed literature assessing solar thermal power plants with capacities of 10–50 MW, parabolic trough was the most popular, followed by solar tower, then linear Fresnel technology and solar dish plants. Parabolic trough was the most dominant solar thermal technology used in the studies which can be attributed to it being the more established and widely commercialised than the other solar thermal technologies. The most common solar thermal power plant size assessed in the literature was 50 MW capacity. The studies used SAM, MATLAB, TRNSYS and a mathematical model in the economic analysis of the plants. SAM was the most popular software used in the studies. A few of the studies did not state the software used for the economic evaluation of the plants. The LCOE was the most preferred economic metric used in all the studies.

Several studies have conducted techno-economic assessment of different types of solar thermal technologies with a variety of plant capacities, with and without TES in different locations across the world. However, it can be difficult to make comparisons of the economic performance of the different solar thermal technologies due to the differences in the direct normal irradiation (DNI) values of the locations, plant capacities, TES inclusion/non-inclusion, and software tools used in the studies [43]. Most of the studies have conducted the economic assessment of a singular type of solar thermal technology, mainly parabolic trough. However, some studies have compared the economic performance of two or more types of solar thermal technologies using the same location [14,17,22,50,51]. Islam et al. [14], Gonzalez-Portillo et al. [17], Soomro et al. [22], Janjai et al. [50] and Purohit et al. [51] were the studies that conducted comparative analysis on the economic performance of different types of solar thermal power plants ranging from 10 MW − 50 MW.

Islam et al. [14], Janjai et al. [50] and Purohit et al. [51] simulated and evaluated the economic performance of different types of solar thermal power plants of 10 MW. Islam et al. [14] used RETScreen Expert Energy Management software to simulate and compare the LCOE, capital cost, NPV and payback period of the PT, ST and SD plants located in Malaysia, while Janjai et al. [50] used TRNSYS software to simulate and compare the LCOE of the PT, ST and SD plants in Thailand. Purohit et al. [51] used SAM software to simulate and compare the LCOE of the ST, LFR and SD plants of 10 MW and 50 MW PT plant in India. The result from all three studies showed that the SD plants had the highest LCOE, whilst the PT plants had a lower LCOE than the ST plants. However, Purohit et al. [51] observed that the LFR had the lowest LCOE of the four solar thermal technologies assessed in the study. Islam et al. [14] found that the SD plant had the highest capital cost at €80 million, followed by the PT plant with a capital cost of €36 million and then the ST plant with a slightly lower capital cost of €35 million. Studies have reported that SD plants have significantly higher capital costs than other solar thermal technologies which has hindered their commercialisation [22,50]. The NPV and IRR of the PT plant was also higher than the ST plant, indicating that the PT plant was more profitable, with the PT plant also having a shorter payback period than the ST plant. Janjai et al. [50] conducted sensitivity analysis of the variables that affected the economic performance of the solar thermal power plants and found that the DNI value and interest rate strongly influenced the LCOE of all three solar thermal technologies with the LCOE value decreasing with a rise in DNI and increasing with rising interest rates. This has been corroborated by other studies who found that the LCOE of solar thermal power plants is highly dependent on the DNI value as well as the interest rate [16,19,23]. Janjai et al. [50] reported that of the three solar thermal technologies, the SD was most sensitive to the interest rate due its higher investment cost and most sensitive to the DNI value due to its lack of thermal storage, therefore its performance relied mainly on the DNI. Islam et al. [14] used a variety of financial metrics to evaluate the economic performance of the solar thermal power plants whilst Janjai et al. [50] and Purohit et al. [51] only used one metric which was the LCOE to evaluate the economic impact of the plants. Islam et al. [14] and Janjai et al. [50] did not include LFR in the economic assessment of the solar thermal power plants. Among the studies reviewed in the literature, assessing of the economic performance of solar thermal power plants, LFR and SD were the least studied solar thermal technologies. SD technology is rarely commercialised due to its very high capital costs whilst LFR plants have the lowest capital costs of the solar thermal technologies and studies have found that they are a promising and cost-effective alternative to parabolic trough plants [34,44,48]. Hence more research should be directed on LFR technologies to gain more understanding of their techno-economic performance compared to PT and ST technologies at different capacities.

Soomro et al. [22] and Gonzalez-Portillo et al. [17] used SAM software to simulate and compare the economic performance of different types of solar thermal power plants of 50 MW. Soomro et al. [22] evaluated and compared the capital costs and LCOE of a PT, ST, LFR plant of 50 MW and a 5 MW SD plant, while Gonzalez-Portillo et al. [17] simulated and compared the LCOE of an LFR and a PT plant. Soomro

Table 2
Studies of solar thermal plants (100 MW-250 MW).

Reference	Agyekum & Velkin [23]	Tahir et al. [24]	Hinkley et al. [25]	Boretti & Castelletto [26]	Rahouma et al. [27]
Type of solar thermal system	Parabolic trough, Solar tower	Parabolic trough	Solar Tower	Parabolic Trough	Parabolic trough
Plant Capacity (MW)	100 MW	100 MW	100 MW	250 MW	100 MW
Economic Assessment Software	SAM	SAM	SAM	N/A	N/A
Economic Assessment Method	LCOE, Net Capital Cost, NPV, IRR	LCOE	Plant Cost, LCOE	LCOE, Capital Cost	Net Capital Cost, LCOE
Economic Impact (Internal)	**LCOE** ST@ Navrongo = ¢13.67/kWh ST @ Tamale = ¢14.73/kWh PT @ Navrongo = ¢25.83/kWh PT @ Tamale = ¢28.60/kWh **NPV** ST @ Navrongo = $3,526,383 ST @ Tamale = $3,526,973 PT @ Navrongo = $3,633,594 PT @ Tamale = $3,633,971 **Internal Rate of Return** ST @ Navrongo = 12.74 %, ST @ Tamale = 12.74 %, PT @ Navrongo = 12.77 %, PT @ Tamale = 12.77 % **Net Capital Cost** ST @ Navrongo =$787,584,256, ST @ Tamale = $787,513,728, PT @ Navrongo = $641,920,128 PT @ Tamale = $641,873,664	**LCOE** Pishin = $14.7 cents/kWh Quetta = $15.3 cents/kWh	**Indicative Plant Cost** PT =$ 8119/kW, ST = $7063/kW **LCOE** PT= $170/MWh @max HTF temp. of 680 °C ST =$158/MWh @ max HTF temp. of 880 °C The LCOE value decreases as the temp. of the HTF increases. **Component Costs** Solar field (PT) = 51 %, ST = 57 %, Power block (PT) = 22 %, ST = 20 %, Indirect Costs (PT) = 17 %, ST = 17 %, Storage (PT) = 8 %, ST = 4 %, Land (PT) = 2 %, ST = 2 %	**Capital Costs** PT with 6hrs TES = $2 billion PT with no TES = $1.25 billion **LCOE** PT with 6hrs TES = $0.15/kWh PT with no TES = $0.08/kWh	**Net Capital Cost without TES** = $371,003,712 **LCOE without TES** = ¢ 18.01 /kWh **Net Capital Cost with TES** (Solar Multiple of 1) = $560,889,280 **LCOE with TES** (Solar Multiple of 1) = ¢24.48/kWh **Net Capital Cost with TES** (Solar Multiple of 2) = $560,889,280 **LCOE with TES** (Solar Multiple of 2) = 24.48 cents/kWh
Economic Impact (External)	N/A	N/A	N/A	N/A	N/A

Reference	Hakimi et al. [10]	Aly et al. [28]	Zhuang et al. [29]	Luo et al. [30]	Abbas & Merzouk [31]
Type of solar thermal system	Parabolic Trough, Solar Tower & PV system	Solar Tower & Parabolic Trough	Solar Tower	Solar Tower Plant	Parabolic trough, Solar Dish, Solar Tower
Plant Capacity (MW)	110 MW (PT & ST)	100MW	100 MW	100 MW	100 MW
Economic Software	SAM	SAM	SAM	SAM	SAM
Economic Assessment Method	LCOE, IRR, Capital Cost	LCOE, Capital Cost	LCOE	LCOE	LCOE, NPV
Economic Impact (Internal)	**LCOE** PT = $0.1076/kWh, ST = $0.146/kWh, PV=$0.063/kWh **IRR** PT = 43.76%, ST = 48.05%, PV= 19.93% **Capital Cost** PT= $431,872,704 ST = $412,680,704 PV = $160,361,152	**LCOE** ST (Wet-cooling) = $11.6cent/kWh ST (Dry cooling) = $12.5cent/kWh PT (Wet)= $13cent/kWh PT (Dry) = $14.4 cent/kWh **Capital Cost** Dry-cooling ST = $7,516/KW PT =$6446/KW Wet-cooling ST =$6,906/KW PT = $5,907/KW	**LCOE** Delingha = RMB 1.45/kWh Linxi = RMB 2.33/kWh Yanqing = RMB 3.5/kWh	**LCOE** Sevilla = 21.77 ₵ /kWh @ SM of 1.7 & 3hr TES San Jose =19.57 ₵ /kWh @ SM of 1.7 & 3hr TES Bishop = 14.62 ₵ /kWh @ SM of 1.3 & 3hr TES	**LCOE** PT = 11 cents/kWh, ST = 12 cents/kWh, SD plant = 14.5cents/kWh **NPV** NPV of PT = $57.9 million NPV of ST = $41.8 million NPV of SD = $28.2 million
Economic Impact (External)	N/A		When the LCOE is equal to the grid parity: 325 RMB/ ton CO2 between 2024 and 2028 162.5 RMB/ ton CO2 between 2031 and 2033	N/A	N/A

et al. [22] and Gonzalez-Portillo et al. [17] presented conflicting results regarding the LCOE of the solar thermal power plants, with the results of Soomro et al. [22] showing that the PT achieved the lowest LCOE, followed by the ST and then the LFR plant. In contrast, Gonzalez-Portillo et al. [17] observed that the LFR had lower LCOE than the PT plant. This could be due to the design optimization conducted with the TES optimised to achieve the least LCOE value for both the LFR and PT plant. There were limited studies in the reviewed literature that performed optimization of LFR plants to achieve their optimal economic performance. Hence future studies should focus in this area, particularly for LFR technology which is one of the least studied solar thermal technology in the literature. Soomro et al. [22] observed that the DNI was

Table 3
Study with solar thermal power plants of mixed capacities (20 MW-200 MW).

Reference	Yang, et al. [4]	Lipu & Jamal [20]
Type of solar thermal system	Solar Tower, Parabolic Trough, Linear Fresnel	Solar Tower, Parabolic Trough
Plant Capacity (MW)	50–135 MW	50 MW (PT), 11 MW (ST)
Economic Assessment Software	N/A	N/A
Economic Assessment Method	Cost-Benefits Analysis, Total Cost of Plant, Static Payback period, Net Present Value Rate (NPVR), IRR	LCOE, NPV, IRR, Benefit to Cost (B/C) Ratio, Payback period
Economic Impact (Internal)	**Solar Power Tower Plants:** Average SP = 12yrs, Average NVPR = 0.3, Average IRR = 12.33 %, Total Investment ranged from RMB 1,050 million - RMB3,040 million **Parabolic Trough Plants:** Average SP = 12.6yrs, Average NVPR = 0.22, Average IRR = 11.72 %, Total Investment ranged from RMB 1,344.77 million – RMB 2,800 million **Linear Fresnel Plants:** Average SP = 13yrs, Average NVPR = 0.18, Average IRR = 11.43 %, Total Investment ranged from RMB 1,476 million – RMB 1,800 million	**Dinajpur** LCOE(PT) = 14.60 Tk./kWh, LCOE (ST) = 13.45 Tk./kWh NPV(PT) = 3977.21 Tk mill, NPV (ST) = 1190.1 Tk mill IRR (PT) = 6.07 %, IRR (ST) = 7.74 % B/C Ratio (PT) = 4.29 %, B/C Ratio (ST) = 4.9 %, Payback = 13.92 years, Payback = 11.55 years
Economic Impact (External)	N/A	N/A

one of the most important parameters affecting the technical and economic performance of a solar thermal power plant which was demonstrated by the plants in locations with high DNI levels achieving the highest capacity factor and annual electricity generation compared to locations with lower DNI values. This was corroborated by Islam et al. [14] who found that the location with the highest DNI value resulted in the solar thermal power plants having greater capacity factor and higher annual electricity production as well as the lowest LCOE value.

Soomro et al. [22] also observed that when the 5 MW solar dish (SD) was included in the economic assessment, the SD plant had the lowest capital cost, followed by the LFR, the PT plant and the ST plant. The solar dish had the lowest capital cost due to its smaller plant capacity of 5 MW compared to 50 MW for the PT, ST and LFR plants. Studies have found that the size of a solar thermal power plant impacts on its capital cost; the bigger the plant capacity, the larger the plant cost [10,62]. The authors found that the SD plant had the lowest LCOE, followed by the PT plant, the LFR and then the ST plant. The low LCOE value of the SD plant was attributed to its high concentration ratio, high operating temperature and higher efficiency resulting in increased power generation and reduced energy cost. Although the ST plant generated the most energy, it had the highest LCOE value due to its high capital costs which increased the LCOE. The factors that affected the LCOE value of the LFR plant were its lower energy production due to its low concentration ratio and efficiency resulting in a higher LCOE [22]. The authors also compared the effects of evaporative (water-cooling) and air (dry) cooling on the performance of the solar thermal technologies. The results showed that using air cooling instead of evaporative cooling reduced the annual energy production, gross-to-net conversion and capacity factor for all the solar thermal technologies which can lead to higher LCOE. This is confirmed by studies who found that dry-cooled solar thermal power plants tend to have higher capital costs than wet-cooled plants [17,26,30]. This is due to dry-cooled plants having lower thermal efficiencies than wet-cooled plants resulting in dry-cooled plants being installed with 9 % larger solar collector field, heat transfer fluid and TES systems than wet-cooled plants in order to compensate for their lower thermal efficiency leading to increased plant costs [30]. Soomro et al. [22] reported that the solar field of the solar thermal technologies contributed the most in the capital cost of the plant which has been corroborated by other studies with similar findings [9,10,11,19]. This was attributed to the costs and challenges of producing curved reflective mirrors, support structures required for the solar field and the use of tracking systems to track the sun. A number of studies have recommended that solar field components be manufactured locally instead of being imported, in order to reduce costs, especially for the solar collectors & receivers which accounts for the largest share of the total plant cost [10,19,20,23]. Krishnamurthy et al. [10] found that manufacturing the solar collectors locally in India reduced costs by 20–30 %, making the costs of solar thermal power plants in India competitive with those in Spain and USA.

Gonzalez-Portillo et al. [17] used SAM software to reduce the LCOE of a PT and LFR plant through optimisation of the thermal energy storage. The authors reported that as the TES capacity increases, a larger solar field is required as the solar field has to provide thermal power to generate electricity as well as to charge the TES. They found that the optimal LCOE was a function of the solar field cost and the plant's relative efficiency. The authors reported that because the efficiency of LFR is typically 10–30 % lower than PT, the cost of LFR should be reduced by 15–40 % compared to PT in order to obtain a breakeven LCOE. Their results showed that the TES was more profitable for cheaper solar fields and that the plant with the cheapest solar field achieved the smallest LCOE when integrated with TES. The authors explained that due to LFR having a cheaper solar field, it has the potential to obtain greater LCOE reduction with the inclusion of bigger TES and that this type of plants can cover the peaks of electricity prices with lower costs resulting in higher profits. The results of the simulations by Gonzalez-Portillo et al. [17] showed that the LFR had a lower LCOE value than the PT plant. More studies should be directed on the effect of optimising the TES and solar multiple of all four main types of solar thermal power plants including LFR plants in order to increase and aid comparison of their economic performances. The LCOE was the most dominant metric used in the studies that compared the economic performance of different solar thermal power plants with a limited use of the other economic metrics such as NPV, IRR, revenues, payback period. This highlights the need for future studies to include these metrics when comparing the economic performance of different solar thermal technologies in order to provide a more comprehensive analysis of the plants.

4.2. Studies with solar thermal power plants of 100 MW – 250 MW

This section presents the economic assessment of solar thermal power plants of 100 MW – 250 MW as depicted in Table 2. Solar tower and parabolic trough were the most common solar thermal technologies assessed in these studies, while solar dish and linear Fresnel were the least assessed technologies. The most popular plant capacity used in these studies was 100 MW, with SAM software being the most commonly used in the economic assessment of the solar thermal power plants. LCOE was the most dominant metric used in all the studies followed by capital costs, then NPV and IRR.

Agyekum & Velkin [23], Aly et al. [28] and Hakimi et al. [10] were the studies that conducted comparative analysis on the economic performance of different types of solar thermal power plants of 100 MW and above. Agyekum & Velkin [23] and Aly et al. [28] used SAM software to simulate and assess the economic performance of 100 MW PT and ST plants [23,28,45]. Agyekum & Velkin [23] used LCOE, capital cost, NPV and IRR, while Aly et al. [28] used LCOE and capital cost to evaluate the financial impact of the plants. Both studies found that although the ST plants had higher capital costs than PT plants which has been corroborated in the literature [9,15,23], the ST plants achieved lower LCOE than the PT plants. Agyekum & Velkin [23] also found that the ST plants had slightly lower NPV and IRR than the PT plants. Both studies optimized the solar multiple and TES of the plants to achieve the least LCOE values. The capacity factor of a solar thermal power plant is determined by the

Table 4
Studies with economic & environmental assessment of solar thermal power plants.

Reference	Aseri et al. [32]	Hirbodi et al. [33]	Banacloche et al. [38]	Backes et al. [39]	Dabwan et al. [34]	Ehtiwesh et al. [47]
Type of solar thermal technology	Parabolic Trough & Solar Tower	Solar Tower (ST) & Parabolic Plant (PT)	Parabolic Trough with biomass technology	Solar Dish plant	Linear Fresnel Plant integrated with a gas turbine	Parabolic Trough
Plant Capacity (MW)	50 MW	20 MW, 50 MW, 100 MW, 200 MW	1 MW	33KW	340 MW	50 MW
Environmental Assessment Software	Mathematical Calculations	SAM	SimaPro	Gabi	Thermoflex + PEACE Software	SimaPro 8
Environmental Assessment method	Embodied CO_2-eq emissions	Life cycle CO_2 emissions reductions, water consumption	Environmental Footprint Method	CML 2001	Thermodynamics analysis - Annual CO_2 emissions savings	Eco-indicator 99 (H)
Environmental Impact	PT (Wet) = 18.9 g – 19 g CO_2eq /kwh, PT (Dry) = 22.6 g – 22.7 g CO_2eq /kwh, ST (Dry) = 10.8 g – 11.3 g CO_2eq /kwh	100 MW ST plant with 14hrs TES reduces CO2 emissions by 399 kilotons. 100 MW PT plant with 6hrs TES reduces CO2 emissions by 228 kilotons	The PT produced 22 g CO_2eq/kwh	34.77 g CO_2eq/kwh	The LFR plant with a gas turbine capacity of 250 MW reduces CO_2 emissions by 45 kilo-tonnes but reduces CO_2 emissions by 110.34 kilo-tonnes when the LFR plant is integrated with a gas turbine of 100 MW.	
Economic Assessment Software	SAM	N/A	N/A	Excel	Thermoflex + PEACE Software	Thermo-economic analysis
Economic Assessment Method	LCOE, Capital cost	LCOE, SAM	Capital Cost	Life Cycle Cost, LCOE	LCOE	LCOE
Economic Impact (Internal)	**Capital Costs** PT (Wet) = \$193.6 million, \$196.8 million, PT (Dry) = \$217 million, \$220.7 million, ST (Dry) = \$169.8 million, \$179.3 million **LCOE (\$/MWh)** PT (Wet) = \$110.3/MWh, \$111.4/MWh, PT (Dry) = \$131.2/MWh, \$133.8/MWh, ST (Dry) = \$95.8/MWh, \$96.4/MWh	**LCOE (15 hrs TES)** 100 MW ST (Dry) = 11.3 cents/kwh 100 MW PT (Dry) = 14.2 cents/kwh 100 MW ST (Wet) = 11cents/kwh 100 MW PT (Wet) = 13.6cents/kwh	**Capital Cost** \$7,015,052	LCC =€308,467 LCOE = €0.268/kwh	**LCOE** Standalone LFR plant = \$28.5 cent/kwh LFR-GTPP = \$4.28 cent/kwh & \$5.6 cent/kwh	**LCOE** Solar field = \$0.197/kwh Boiler = \$0.234/kwh HP Turbine = \$0.242/kwh Condenser = \$0.249/kwh Pump = \$0.302/kwh Solar field = \$17,635/h Boiler = \$2526/h Condenser = \$1104/h
Economic Impact (External)	N/A	N/A	N/A		N/A	N/A

Reference	Ko et al. [40]	Salisu et al. [9]	Corona et al. [13]	Corona & San Miguel [41]	Mihoub et al. [42]	Bellos et al. [48]	Kuenlin et al. [49]
Type of solar thermal system	Solar Tower Plant	Parabolic trough, Solar tower, Linear Fresnel	Parabolic trough	Parabolic Trough, Solar Tower	Linear Fresnel	Linear Fresnel	Parabolic trough, linear Fresnel, Solar tower, Solar dish
Plant Capacity (MW)	101 MW	50MW, 75MW & 100MW	50 MW	50MW (PT), 180 MW (ST)	50MW	48MW	N/A
Environmental Assessment Software	Gabi	Umberto NXT	SimaPro 8.0	SimaPro 8.0.3	SAM	SAM	SimaPro
Environmental Assessment Method	CML 2001	N/A	IPCC 2013	ReCiPe Midpoint & Endpoint (H), Cumulative Energy Demand (CED), Water Stress	N/A	N/A	Impact 2002+
Environmental Impact	The ST plant produced 24.3g CO_2eq/kwh	The ST plant produced 12.2g CO_2eq/kwh	The PT produced 27.6g CO_2eq/kwh	Solar Tower HYSOL (Biofuel) plant = 45.9 kg CO_2eq/MWh Solar Tower HYSOL (Natural Gas) plant = 294 kg CO_2eq/MWh	The back-up system fuelled by natural gas was the most significant contributor to GHG emissions, producing 95kgCO_2 eq/MWh, contributing over 90% of the total emissions.	The LFR plant will reduce carbon-dioxide emissions by 420,672 tons annually.	Manufacturing & construction of the plants had the most environmental impact (86%-99%) mainly due to the solar field, storage & heat transfer fluid.

(*continued on next page*)

Table 4 (*continued*)

Reference	Ko et al. [40]	Salisu et al. [9]	Corona et al. [13]	Corona & San Miguel [41]	Mihoub et al. [42]	Bellos et al. [48]	Kuenlin et al. [49]
Economic Assessment Software	Gabi	SAM	SimaPro	Multi-regional input–output analysis	SAM	SAM	N/A
Economic Assessment method	Plant construction cost, NPV, Revenues Gabi Software	LCOE, NPV, Total Cost of Installation	Full Environmental LCC method, Total Plant Cost, Civil Engineering & Construction Costs, Operation & Maintenance Costs, Disposal Costs, Revenues, NPV, Marginal Damage Costs (MAC) for GHG emissions	Life Cycle Cost	LCOE, Total installed costs	Capital cost, NPV, LCOE	LCOE
Economic Impact (Internal)	Plant Construction Cost = €478,892,010 Revenues = €66.5/MWh NPV = €43,364,197	Highest LCOE (LFR) = 26.33 cent/kWh LCOE (PT) = 18.04 cent/kWh Lowest LCOE (ST) = 17.71 cent/kWh Wet Cooling gave the least LCOE values: LCOE (ST) = 17.1 cent/kWh LCOE (PT) = 15.24 cent/kWh, Highest NPV = $461.05 million (100MW, wet cooled PT), Lowest NPV = $ 17.65 million (50 MW, dry cooled LFR) PT (100MW) has the highest total installation cost (TIC) of $643.90 million. 50MW ST has a TIC of $389.15 million.	Total Plant Cost = €162.9 million Civil Engineering & Construction Cost = €97.1 million O&M Costs = €7.127 million Disposal Costs = €4.867 million Total revenues from electricity sales = 85.7€/MWh, Internal NPV = 2.95€/MWh.	LCC (PT plant) = $192/MWh LCC (Solar Tower HYSOL BIO plant) = $211/MWh LCC (Solar Tower HYSOL NG plant) = $154/MWh	**LCOE of Plants with 8 hr Storage** ST = 29.88¢/kWh PT = 34.43 ¢/kWh Total Installed Costs (ST)= $309 million, (PT) =$312 million **Optimal LCOE & TIC prices were with Backup & 8hrs storage** LCOE (ST) = 23.5 /kWh LCOE (PT) = 24.12 /kWh	Capital Costs = $393 million NPV =$47 million LCOE = $0.0382/kwh	The lower the environmental impact of the plant, the higher the LCOE value.
Economic Impact (External)	N/A	N/A	External costs of atmospheric emissions = 1.87€/MWh (realistic scenario) & 2.14€/MWh (ambitious climate change scenario)	N/A	N/A	N/A	A carbon tax of $60/ton of CO_2eq will make solar tower technology more attractive than natural gas plants.

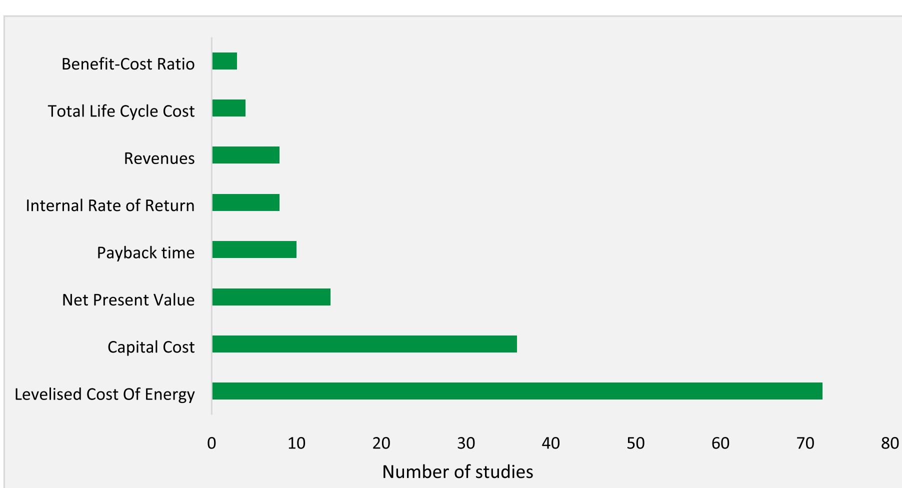

Fig. 1. Frequency of financial metrics used in the literature.

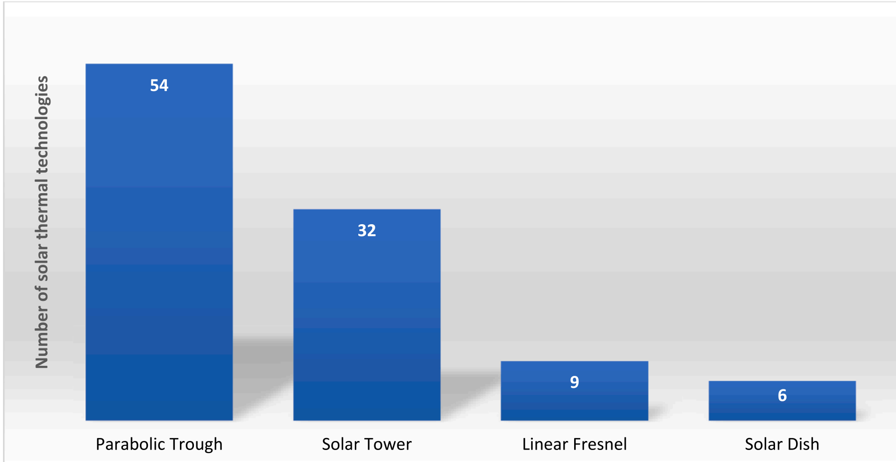

Fig. 2. Frequency of solar thermal technologies used in the studies.

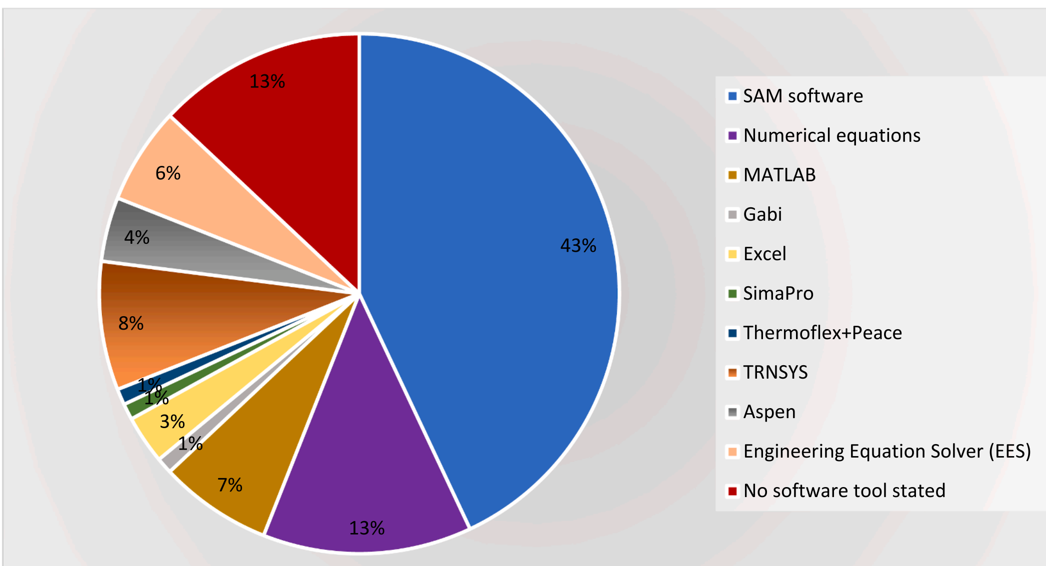

Fig. 3. Proportion of software tools used in the economic assessment of the solar thermal power plants.

sizing of the solar field, storage tank and power block, with a smaller solar field leading to less thermal energy delivered to the power block, thus affecting its capacity factor. It was observed that increasing the solar multiple of a plant integrated with TES increased the use of the power block resulting in LCOE reduction of the plant. However, increasing the solar multiple (SM) also raised the capital cost of the plant. In order to overcome this effect, optimization is required to obtain the solar multiple value that gives the least LCOE when the plant is integrated with TES. The authors also performed sensitivity analysis of the factors that influenced the LCOE and NPV of the plants and observed that the annual interest rate had a significant impact on the LCOE of both the ST and PT plants, while the real discount rate had a substantial effect on the NPV, with the NPV decreasing with rising real discount rates [23].

Aly et al. [28] modelled 100 MW PT and ST plants using dry and wet-cooled options at two different locations in Tanzania. The results showed that the LCOE of the ST plants was lower than the PT plants using both dry and wet-cooled systems. However, the LCOE values of the wet-cooled ST and PT plants were lower compared to the dry-cooled plants. This is corroborated by other studies who reported similar results [32,33] and is due to the higher power cycle efficiency and lower power block costs of wet-cooled plants compared to dry-cooled plants. Aly et al. [28] observed that the LCOE of the PT plant reduced slightly when the TES capacity was increased above 2 full load hours compared to the LCOE of the ST plant which reduced significantly with increasing TES hours. This was attributed to the techno-economic characteristics of a ST plant, where the higher temperature range across its TES system resulted in more energy being stored per mass of molten-salt leading to lower TES cost for ST plants compared to PT plants. Furthermore, molten-salt ST plants which use molten-salt was the heat transfer fluid as well as the TES working fluid do not need heat-exchangers and the corresponding auxiliary systems required for PT plants leading to reduced TES costs in ST plants. ST plants also have higher operating temperatures than PT plants resulting in higher thermal-to-electric conversion efficiencies in the power block and reduction of TES costs. The authors observed that although the net capital cost per installed capacity for ST plants is higher at low TES capacity, at high TES capacity the net capital cost per installed capacity of a ST plant is lower than a PT plant. Aly et al. [28] also investigated the hybridization of a 100 MW PT with a TES of 4 h with natural gas as the backup system. The results showed that increasing the natural gas backup system capacity resulted in reduction of the LCOE, but increased the annual fuel and water consumption. The authors performed sensitivity analysis on the effect of the project's debt annual interest rate and imposed sales tax on the LCOE value. It was found that varying the project's debt annual interest rate had a huge impact on the LCOE, with the LCOE rising from 14.4 cents/kWh at 7 % interest rate for government-led solar thermal power projects to 25.9 cents/kWh at 18 % for private investors-led projects. The authors reported that solar thermal power projects were economically competitive at 7 % interest rate but uncompetitive at 18 % interest rate and recommended that favourable financing terms should be used for solar thermal power plants to make them economically viable and competitive with non-renewable projects. This recommendation is supported in the literature by other studies who report that governmental incentives, subsidies and cheaper loan terms are required for solar thermal power projects [10,23].

Hakimi et al. [10] used SAM software and an in-house computer code to simulate and conduct a techno-economic assessment of a 110 MW PT, ST and PV plant located in Afghanistan. The results showed that the PV plant had the lowest LCOE, followed by the PT (with and without TES) and then the ST plant. The capital cost of the PV plant was also substantially lower than the PT and ST plants which contributed to its low LCOE value. The capital cost of the PT plant without storage was slightly higher than the ST plant. However, when the PT plant was integrated with 7.5 h TES, its capital cost rose by 50.8 % indicating that the inclusion of TES in a solar thermal power plant can substantially increase its capital cost. The solar tower plant had the highest IRR, followed by the PT and then the PV plant, suggesting that the ST is the most profitable. The PV plant had the shortest payback time of 8 years, whilst the PT and ST plant had the same payback time of 10 years.

4.3. Studies with solar thermal power plants of mixed capacities (11 MW-135 MW)

This section presents studies with mixed capacity of 11 MW – 135 MW as shown in Table 3. Parabolic trough, solar tower and linear Fresnel were the three solar thermal technologies evaluated in these studies One study assessed the economic performance of solar thermal power plants of 50 MW –135 MW capacity, while the other study assessed the economic impact of a 11 MW solar tower and 50 MW parabolic-trough plant. The LCOE, NPV, IRR, payback period, total investment cost, benefit-cost ratio were the metrics used to evaluate the economic performance of these plants.

Yang et al. [4] and Lipu & Jamal [20] assessed the economic impact of different types of solar thermal power plants of mixed capacity. Yang et al. [4] evaluated the economic performance of PT, ST and LFR plants with capacities ranging from 50 MW –135 MW located in different places with varying DNI values in China, while Lipu &Jamal [20] assessed a 50 MW PT and a 11 MW ST plant at various locations in Bangladesh. Both studies used numerical equations as well as a wide range of financial metrics including LCOE, NPV, IRR, benefit-to-cost ratio and payback period in the economic evaluation of the plants. The studies by Yang et al. [4] and Lipu & Jamal [20] can be improved by the authors simulating the different solar thermal power plants using similar capacities, design and modelling conditions to achieve a more accurate economic evaluation of the plants. The results of the study by Yang et al. [4] revealed that overall, the PT plants had the highest investment cost per capacity, followed by the LFR plants and then the ST plants which could be due to the number of thermal storage hours. The PT plants had larger TES capacity ranging from 9 to 16 h, whilst the LFR plants had TES capacity of 8–14 h and the ST plants had lower TES capacity of 6–11 h. Studies have shown that plants with larger TES capacity have higher investment costs compared to plants with lower TES capacity. The ST plants had the highest average NPV rate (NPVR), IRR and the shortest payback time followed by the PT and then the LFR plants, indicating that the ST plants were the most profitable which could be due to their high thermal conversion efficiency. Solar thermal technologies are characterised by high initial investment costs, low operation and maintenance costs with very little or no fuel cost. Significant reduction of initial investment costs can be achieved by the increased deployment of larger solar thermal power plants resulting in mass production of equipment, materials and optimization of solar thermal systems leading to significant reduction of initial investment costs [4]. Furthermore, the initial costs can be reduced by the experience gained by engineers, technical personnel and contractors through the construction of several solar thermal power plants resulting in design and construction improvements. This is known as learning curves, where reduction in the initial investment costs is proportional to the learning rate with the growth of total installed capacity [4,16]. A learning rate of 10 % has been suggested by the International Energy Agency (IEA) for power generation cost calculations of solar thermal power plants [7,16].

Lipu & Jamal [20] conducted techno-economic analysis of a 50 MW PT and 11 MW ST plant at various locations in Bangladesh. Dinajpur had the highest DNI value, therefore the economic performance of the plants in Dinajpur are presented in this paper. The results showed that the ST plants had lower LCOE and NPV than the PT plants. However, this could be attributed to the smaller capacity of the ST plant at 11 MW resulting in lower investment cost, LCOE and NPV. Studies have reported that the NPV of a solar thermal power plant corresponds to the size of the plant, with large-scale plants having higher NPV compared to small-scale plants [7,23]. The ST plant had a higher IRR and benefit-cost ratio and shorter payback period compared to the PT plant, indicating that the ST plant was more profitable than the PT plant which was corroborated by Yang et. Al. [4] who reported similar results in their study. However, the results of the study by Lipu & Jamal [20] could be influenced by the different plant capacity used for the PT and ST plants. To improve their study, the authors use the same capacity for both the PT & ST plants to enable a more effective comparison of the economic impact of both technologies. A number of the studies in the reviewed literature optimised the design of the solar thermal power plants, particularly the solar multiple and TES in order to achieve the least LCOE value [9,10,16,18,23,24,25,27,28,30,32,33,34,42]. However, the majority of the design optimization were based on PT and ST technologies, with very few studies in the reviewed literature optimizing the design parameters of LFR or SD plants to obtain their optimal LCOE values. Hence there's a need for more design optimization studies of LFR and SD technologies that focus on the economic performance of these plants to enable comparisons with PT and ST technologies. The LCOE values obtained from the studies that performed design optimization of the solar thermal power plants are likely to be more optimal than the LCOE values obtained from studies that did not optimize the design parameters of the plants. Optimization of the parameters of the solar thermal power plants improves both the techno-economic performance and financial feasibility of the plants.

4.4. Studies with integrated environmental & economic assessments of the solar thermal power plants

This section presents the studies with integrated environmental and economic assessment of the solar thermal power plants which are displayed in Table 4. A number of software tools were used for their economic evaluation including System Advisor Model (SAM), SimaPro, Umberto, Gabi and Thermoflex + Peace software. The LCOE was the most popular economics metric, followed by capital costs, NPV, revenues and then life cycle costs (LCC). SAM was the most commonly used software for the economic assessment while SimaPro was the most popular used for the environmental assessment of the plants.

Aseri et al. [32] compared the economic and environmental performance of a 50 MW parabolic trough (PT) and solar tower (ST) plant. The authors found that the capital costs and LCOE of ST plants were less than PT plant, with ST plants producing less GHG emissions than PT plants. Furthermore, the authors observed that the capital costs and LCOE of dry-cooled PT plants were higher than wet-cooled PT plants which was corroborated by Salisu et al. [7] and Hirbodi et al. [33] who found that the LCOE of dry-cooled PT and ST plants were higher than that of their wet-cooled counterparts. The authors also observed that the LCOE values for both PT & ST plants decreased as their capacity increased from 20 MW – 200 MW. In addition, it was reported that dry-cooled ST plants achieved higher CO_2 emissions reductions than dry-cooled PT plants with the dry-cooled 100 MW ST plant with a TES of 14hrs being the most efficient configuration achieving an annual reduction of 399 kilo-tons of carbon emissions and annual fossil fuel savings of 190 million m^3 of natural gas [33]. Dabwan et al. [34] performed an economic-thermodynamic-environmental assessment of a 340 MW LFR integrated with a gas turbine power plant (GTPP) of different capacities ranging from 100 to 250 MW. The authors found that integrating the LFR with a gas turbine results in lower LCOE values of $4.28 cent/kWh and $5.6 cent/kWh compared to a standalone LFR plant which achieved higher LCOE of $28.5 cent/kWh. This highlights the economic and environmental trade-offs that investors or owners of solar thermal power plants are likely to make – to either have a solar thermal power plant integrated with fossil-fuel that may be less expensive but results in higher GHG emissions or use a standalone solar thermal power plant that may be more expensive but with lower GHG emissions. One of the options is to replace the auxiliary fuels used in solar thermal power plants which is usually natural gas with biofuels instead. Studies have investigated the use of biogas, wheat straw, wood pellets and bio-methane as auxiliary fuels in solar thermal power plants and found it resulted in reduced GHG emissions, however, their economic impacts were not assessed [35,36,37]. Corona and San Miguel [41] conducted a life cycle sustainability analysis of HYSOL (NG) and HYSOL (BIO) solar tower plants and a parabolic trough plant. The analysis included the economic, environmental and social impact of the plants. The authors found although the life cycle cost (LCC) of the HYSOL (NG) solar tower plant was lower than the LCC of the HYSOL (BIO) solar tower plant, it produced significantly greater GHG emissions of 294 $kgCO_2eq/MWh$ compared to the HYSOL (BIO) plant which produced 45.9 $kgCO_2eq/MWh$. The LCC of the parabolic trough plant was $192/MWh which was lower than the HYSOL (BIO) solar tower plant at $211/MWh [41]. Only one study in the reviewed literature assessed the economic performance of solar thermal power plants with biofuels as its auxiliary fuel. It would be useful for more research to be conducted on the economic impact of biofuels replacing natural gas as the auxiliary fuel in solar thermal power plants.

Corona et al. [13] was the only study in the reviewed literature that conducted a full environmental and economic assessment of a solar thermal power plant including the external environmental costs of the plant. The authors performed a full environmental life cycle costing (LCC) of a 50 MW PT plant operating in hybrid mode with different natural gas inputs (between 0 % and 30 %). The LCC included both the internal and external costs of the plant. The internal costs are the purchase of materials and equipment incurred mainly during the extraction and manufacturing life cycle phase of the plant, while the external costs are the environmental costs associated with atmospheric emissions. The authors found that the external environmental costs of the PT plant with 30 % natural gas were up to 8.6 times higher than in solar-only operation, due to the increased GHG emissions. It was reported that the internal costs increased from €82.8/MWh to €89/MWh and the external costs also rose from €1.87/MWh to €12.8/MWh (realistic scenario) when the share of natural gas was increased from 0 % to 30 % in the PT plant [13]. The components of the solar thermal plant can impact on its economic and environmental performance. Ehtiwesh et al. [47] found that the solar field of a PT plant had the highest cumulative energy demand (CED) at 0.126 MJ/kWh, followed by the storage system at 0.035 MJ/kWh and then the power block at 0.003 MJ/kWh. This reveals that the solar field and the thermal energy storage are the two main subsystems that require more attention in reducing the energy demand and GHG emissions of solar thermal power plants. Studies have found that the solar field represents the highest cost of a solar thermal power plant [12,25,47]. Ehtiwesh et al. [47] observed that the solar field had the highest cost at $17,635/h, followed by the boiler at $2,526/h and then the condenser at $1104/h. This highlights the need for additional effort to be directed in reducing the costs and the environmental impact of the solar field by focusing more research on inexpensive materials with low environmental and economic impact that can be used for the components of the solar field of the plant.

5. Economic performance of integrated solar combined cycle (ISCC) power plants

This section presents the studies with economic assessment of integrated solar combined cycle (ISCC) power plants displayed in Table 5. A number of software tools were used for their economic evaluation including SAM, Aspen Plus, MATLAB, EES software as well as numerical equations. The LCOE was the most popular economics metric, followed by capital costs, revenues and NPV.

The economic performance of various types of ISCC power plants are presented in Table 5. Wang et al. [52], Benabdellah & Ghenaiet [54] and Alqahtani & Patino-Echeverri [55] assessed the economic performance of PT solar collector integrated with combined cycle gas turbines (ISCC). Wang et al. [52] conducted a thermodynamic and economic analysis of an ISCC-PT plant of 440 MW in China, while Benabdellah & Ghenaiet [54] performed an energy, exergy and economic analysis of ISCC-PT plant of 160 MW located in Algeria. Alqahtani & Patino-Echeverri [55] conducted economic and environmental analysis of an ISCC-PT plant of 550 MW and compared the results with a standalone CSP plant and a natural-gas fired combine cycle (NGCC) plant in USA. The 550 MW ISCC plant had the lowest LCOE at 5 cent/kWh, followed by 440 MW ISCC plant at 7.94 cent/kWh and then the 160 MW ISCC plant at 12.71 cents/kWh. This LCOE values could be attributed to the capacities of the plants as studies have found that larger plant capacities have lower LCOE values. DNI values can also affect the LCOE, with higher DNI values resulting in higher energy generation and lower LCOE [52]. Benabdellah & Ghenaiet [54] and Alqahtani & Patino-Echeverri [55] both compared the LCOE value of the ISCC plants with standalone combined cycle gas turbine (CCGT) plants and found that the LCOE of CCGT plants were lower than that of ISCC plants. However, Benabdellah & Ghenaiet [54] observed that when the ISCC plant is integrated with TES, its annual fuel saving was $60 million and the high initial investment cost of the plant could be amortized in about 3 years making the ISCC plant with TES economically viable. Wang et al. [52] found that the LCOE was strongly influenced by the specific investment cost of the solar field, with the LCOE decreasing as the cost of the solar field falls. The authors noted that the cost of the solar field is expected to reduce significantly in the future due to mass production making them cost-competitive. When the annual capacity factor of the ISCC is 10 % lower than the NGCC, the LCOE of the ISCC is higher than that of the NGCC, while the cost of carbon abatemet (CoA) of the ISCC becomes less than that of the NGCC when natural gas prices exceed $17/MMBtu. Wang et al. [52], Benabdellah & Ghenaiet [54] and Alqahtani & Patino-Echeverri [55] used numerical equations of the financial metrics to calculate the economic impact of the ISCC plants and did not perform optimisation of the ISCC plants to achieve the least LCOE values.

Li & Xiong [56], Adibhatla & Kaushik [57] and Aldali & Morad [59] assessed the economic performance of PT solar collectors integrated with CCGT using direct steam generation technology (DSG-ISCC). Li & Xiong [56] performed thermo-economic analysis of a novel cascade integrating solar combined system using PT and evacuated tube solar collectors of 594 MW in China, while Adibhatla & Kaushik [57] conducted an energy, exergy and economic analysis of a DSG-ISCC plant of 470.3 MW in India. Aldali & Morad [59] conducted numerical simulations of a DSG-ISCC plant of 403.34 MW located in Libya. Adibhatla & Kaushik [57] and Aldali & Morad [59] used numerical equations of the financial metrics, whilst Li & Xiong [56] used the Aspen Plus software and numerical equations to assess the economic performance of the

Table 5
Studies with economic assessment of ISCC power plants.

Reference	Wang et al. [52]	Alkaseem [53]	Benabdellah & Ghenaiet [54]	Alqahtani & Patino-Echeverri [55]	Li & Xiong [56]
Type of solar thermal system	Parabolic Trough integrated with a Combined Cycle Gas Turbine (CCGT)	Solar Tower integrated with a CCGT	Parabolic Trough integrated with CCGT	Parabolic Trough integrated with CCGT	Parabolic Trough with DSG technology & Evacuated Tube solar collectors integrated with a combined cycle system.
Plant Capacity (MW)	450 MW – 50 MW (PT) & 390 MW (CCGT)	548.4 MW – 50 MW (ST) & 498.4 MW (CCGT)	160 MW (ISCC-PT Plant)	550 MW – 50 MW (PT) & 500 MW (CCGT)	594 MW
Economic Software	Numerical equations	SAM & Numerical equations	Numerical equations	Numerical equations	Aspen Plus software & Numerical equations
Economic Assessment Method	LCOE, Capital Cost, Payback time, Revenues, Fuel Cost Savings	LCOE, Capital Cost, NPV	LCOE, Fuel Cost Savings	LCOE	LCOE, Capital cost, Payback period
Economic Impact - Internal	**LCOE** ISCC = \$79.42/MWh equates to \$7.94 cents/ kWh **Capital Cost** PT solar field = \$286.57/ m^2 **Revenues** ISCC = \$1097/MWh **Payback Time** ISCC = 13.12 years **Fuel cost saving** ISCC = \$1.86/MWh	**LCOE** ISCC = 12.71cents/ kWh **Capital Cost** ISCC= \$294 million **NPV** ISCC = \$10.2 million	**LCOE** ISCC-PT plant = 9.75 cent/kWh Standalone CCGT plant = 6.38 cent/kWh ISCC-PT with TES = 11.88 cent/ kWh **Annual Fuel Cost Savings** ISCC-PT with TES = \$60 million per year ISCC-PT without TES = \$30.76 million per year	**LCOE** **@ NG Price of \$4/MMBtu** NGCC = 4.8 cent/kWh ISCC = 5 cent/kWh **@NG Price of \$18/ MMBtu** NGCC = 13.8 cent/kWh ISCC = 13.7 cent/kWh **LCOE of Standalone CSP** CSP (No TES) = 19.94 cent/kWh CSP (2hr TES) = 20.42 cent/kWh CSP (18hr TES) = 24.9 cent/kWh	LCOE = 0.06 \$/kWh Capital Costs = \$482.9 million Payback period = 5.5 years
Economic Impact - External	**CO_2 Emissions Cost Reduction** = \$88.40 kg/ MWh	N/A	**CO_2 Emissions Cost Savings** ISCC-PT without TES = \$13 million annually ISCC-PT with TES = \$26 million per year & saves 0.3 million tons of CO_2 emissions annually	**Cost of CO_2 Emissions Abatement @NG Price of \$4/MMBtu** NGCC= \$40/ton, ISCC= \$43/ton **@NG Price of \$18/ MMBtu** NGCC= \$198/ton, ISCC= \$192/ton CSP (No TES) = \$152, CSP (2hrs TES) = \$157, CSP (18hrs TES) = \$205	N/A

Reference	Adibhatla & Kaushik [57]	Elmorsy et al. [58]	Aldali & Morad [59]	Javadi et al. [60]	Trevisan et al. [61]
Type of solar thermal system	Parabolic Trough integrated with combined cycle gas turbine using direct steam generation (DSG- ISCCPP)	DSG-ISCC with PT, ST & LFR systems	Parabolic Trough integrated with CCGT using DSG technology (DSG-ISCCPT)	Solar Tower integrated with Combined Cycle Gas Turbine (CCGT)	Solar Tower integrated with Combined Cycle Gas Turbine (CCGT)
Plant Capacity (MW)	470.30 MW	525 MW	403.34 MW	370.4 MW	300 MW
Economic Software	Numerical equations	Numerical equations	Numerical Equations	EES Software & Numerical equations	MATLAB
Economic Assessment Method	LCOE, Capital Cost, Annual Benefit/ Revenues, Payback period	LCOE, Capital Cost	Benefit-Cost Ratio, Revenues	LCOE, Capital Cost	LCOE
Economic Impact - Internal	**LCOE** DSG-ISCCPP = \$0.067/kWh CCPP = \$0.074/kWh **Capital Cost** DSG-ISCCPP = \$340.71 million CCPP = \$284.51 million **Net Annual Benefit** DSG-ISCCPP = \$63.02 million CCPP = \$30.67 million **Payback Period** DSG-ISCCPP = 5.41 years CCPP = 9.28 years	**LCOE** DSG-ISCC-LFR1= \$37.36/MWh DSG-ISCC-LFR2= \$36.92/MWh DSG-ISCC-LFR3= \$36.91/MWh DSG-ISCC-PT= \$38.62/MWh DSG-ISCC-ST= \$36.75/MWh **Capital Cost** DSG-ISCC-LFR1= \$451 million DSG-ISCC-LFR2= \$432 million DSG-ISCC-LFR3= \$431 million DSG-ISCC-PT= \$489 million	**Benefit Cost Ratio** Fuel saving mode = 1.74 Power boosting mode = 1.3 **Annual Revenues (Fuel Saving)** Fuel saving mode = \$2.87 million per year Power boost mode = \$2.15 million per year	**LCOE** Configuration A= 3.98 cent/ MWh Configuration B = 4.11 cent/ MWh Configuration C = 3.96 cent/ MWh **Capital Cost of ST** Configuration A = \$46.87 million Configuration B = \$98.02 million Configuration C = \$98.12 million	**LCOE** ISCC-ST with TES = \$117.69/MW CSP-ST = \$137/MW CCGT = \$54.01/MW

(continued on next page)

Table 5 (*continued*)

Reference	Adibhatla & Kaushik [57]	Elmorsy et al. [58]	Aldali & Morad [59]	Javadi et al. [60]	Trevisan et al. [61]
		DSG-ISCC-ST= $426 million			
Economic Impact - External	N/A	N/A	N/A	N/A	N/A

DSG-ISCC plants. The 594 MW DSG-ISCC plant had a LCOE of $0.06/kWh and a capital cost of $482.9 million compared to the 470.3 MW plant which had a slightly higher LCOE of $0.067/kWh and a lower capital cost of $ 340.71 million. This could be due to the capacity of the DSG-ISCC plants with the 594 MW having a higher capital cost than the 470.3 MW plant due to its larger plant size. Studies have found that the capital cost rises while the LCOE decreases with increased plant capacity [10,33,62]. Adibhatla & Kaushik [57] compared the LCOE and capital cost of the 470.3 MW with a conventional combined cycle gas power plant (CCPP) of similar capacity and observed that although the DSG-ISCC had higher capital costs than the CCPP, the DSG-ISCC had a lower LCOE of $0.067/kWh compared to $0.074/kWh for the CCPP. In addition, the net annual benefit of the DSG-ISCC was.

double that of the CCPP, at $63.02 million compared to $30.67 million for CCPP with the DSG-ISCC also having a shorter payback period of 5.41 years compared to 9.28 years for the CCPP. Li & Xiong [56] compared the performance of the PT & ET solar collectors integrated with combined cycle (DSG-ISCC-ET) system with that of a DSG-ISCC and conventional CCGT systems and observed that the DSG-ISCC-ET system demonstrated superior thermo-economic performance than the reference DSG-ISCC and CCGT systems, with the DSG-ISCC-ET system achieving a solar thermal share of 27.8 % which is 17.3 % higher than the DSG-ISCC system. The DSG-ISCC-ET also attained a higher net power output of 594 MW compared to 568.7 MW for the DSG-ISCC and 453.7 MW for the CCGT system. The authors also observed that the novel system achieved greater exergy efficiency of 60.9 % which was higher than the reference DSG-ISCC and CCGT systems by 4.3 % and 12.2 %, respectively as well as a higher fossil-fuel savings ratio of 23.6 % compared to 20.2 % for the DSG-ISCC system. It was also reported that the DSG-ISCC-ET system achieved a LCOE of $0.06/kWh which is 20 % lower than the LCOE of the reference DSG-ISCC in the literature. Li & Xiong [56] optimized the design of the DSG-ISCCPT plant to achieve the least LCOE value by optimizing the tilt angles of the first and second rows of the PT solar collectors as well as the distance of the neighbouring rows in order to minimise the amount of shadowing between the neighbouring rows which can negatively impact the sunlight absorption and solar efficiency of the PT system. The authors found that maximum net annual solar thermal energy was achieved with the first and second tilt angles at 33° and 17°, respectively, and the distance of neighbouring rows of 3 m. Achieving maximum net annual solar thermal energy is likely to result in higher electricity generation of the DSG-ISCCPT plant leading to lower LCOE.

Alkaseem [53], Javadi et al. [60], Trevisan et al. [61] assessed the economic impact of solar tower system integrated with combined cycle gas turbines (ISCC-ST) power plants. Alkaseem [53] conducted an economic analysis of an ISCC-ST plant of 548.4 MW in Saudi Arabia while Trevisan et al. [61] performed a techno-economic analysis of an ISCC-ST plant of 300 MW with TES in Spain. Javadi et al. [60] conducted an energy, exergy, economic and environmental analysis of three different configurations of an ISCC-ST plant of 370.4 MW located in Iran. Alkaseem [53], Javadi et al. [60] and Trevisan et al. [61] used numerical equations of the financial metrics, while Alkaseem [53] used SAM software to assess the economic impact of the ISCC-ST plants. Trevisan et al. [61] compared the economic and environmental impact of an ISCC-ST integrated with TES with a standalone solar tower CSP plant and a CCGT plant and observed that the LCOE of the ISCC-ST integrated with TES had a lower LCOE than a standalone solar tower CSP plant but had a higher LCOE than the CCGT plant which is also confirmed by Alqahtani & Patino-Echeverri [55]. However, Trevisan et al. [61] found that the ISCC-ST integrated with TES had lower carbon emissions of 192.78 $kgCO_2$/MWh compared to 464.91$kgCO_2$/MWh for the CCGT plant. Alkaseem [53] conducted design optimization of the ISCC-ST plant by optimizing the orientation of the solar panels and collectors of the solar tower system to increase its optical efficiency and maximize the solar radiation yield of the plant throughout the year. The solar field was also optimised to have 9026 heliostats to generate the required capacity of 50 MW. A parametric analysis was also conducted to ascertain the optimal solar multiple value that results in the highest annual energy generation and lowest LCOE of the plant. The results showed that the optimal value of the solar multiple was 1.6, resulting in highest annual energy generation of 220.89 MW and lowest LCOE at 12.71 cents/kWh.

Elmorsy et al. [58] conducted a comparative analysis of LFR, PT and ST collectors integrated with combined cycle gas turbines. Direct steam generation was used for the LFR and solar tower systems, but thermal oil was used instead for the PT system. The LFR and ST systems using DSG achieved a lower LCOE and capital costs than the PT system, with the ST system achieving the lowest LCOE and capital costs at $36.75/MWh and $426 million, respectively. This was followed by the LFR plant with a LCOE at $36.91/MWh and capital costs at $451 million for its A3 configuration. The PT system had the highest LCOE and capital costs at $38.62/MWh and $489 million due to its relatively low operating temperature of 393 °C through the use of thermal oil as its heat transfer fluid and its higher heliostats aperture area. The ST system achieved the lowest LCOE and capital costs due to its high operating temperature of 565 °C, thus requiring smaller heliostats aperture area. In addition, the ST system's higher optical and thermal efficiency leads to greater electricity production resulting in its low LCOE value. To improve the comparative analysis of the LFR, PT and ST collectors integrated with combined cycle gas turbines, the authors should use the same working fuel for all three technologies. In the study by Elmorsy et al. [58], water/steam was used as the working fluid for the LFR and ST systems whilst thermal oil was used for the PT system which placed the PT system at a disadvantage as the maximum operating temperature of thermal oil typically does not exceed 400 °C. Among the studies on the economic performance of ISCC power plants in the reviewed literature, Li & Xiong [56] and Alkaseem [53] were the studies that optimized the performance of the ISCC plants resulting in optimal LCOE values and economic feasibility of the plants. The other studies did not perform optimisation of the ISCC systems, therefore it is likely that these plants may not have achieved the lowest possible LCOE values. There were limited studies in the literature assessing the economic performance of ISCC plants with capacities of 250 MW and above, with very few studies conducting comparative analysis of the economic impact of LFR, PT and ST integrated with CCGT. Most of the current studies in the literature focused on the thermodynamic and technical performance of a singular type of solar thermal system integrated with CCGT, particularly PT systems, with only a few studies based on the economic performance of the ISCC plants with larger capacities of 250 MW and above. It is difficult to compare the economic performance of the different solar thermal technology ISCC power plants due to the varying locations and year of studies resulting in variability in the natural gas prices which affects the economic impact of the ISCC power plants. Therefore, simulation of different solar thermal technologies integrated with CCGT system must be performed using homogeneous design and modelling conditions to enable the economic comparison of different ISCC systems.

6. Economic performance of hybrid solar thermal power plants

This section presents the studies with economic assessment of hybrid solar thermal power plants displayed in Table 6. A number of software tools were used for their economic evaluation including SAM, TRNSYS, MATLAB, Excel, ASPEN, EES software as well as numerical equations. The LCOE was the dominant economics metric in the assessment of the plants, followed by the capital costs.

The economic performance of different types of hybrid solar thermal power plants are presented in Table 6. Platzer [71], Starke et al. [72], Parrado et al. [73], Pan & Dinter [74], Elmadioune et al. [85], Hassani et al. [86], Guccione et al. [94], Starke et al. [95], Youssef et al. [97], Acosta-Pazmino et al. [101] and Bousselamti & Cherkaoui [102] conducted economic assessment of hybrid solar thermal-PV plants ranging from 0.083 MW to 150 MW using SAM and TRNSYS software. Platzer [71], Parrado et al. [73], Starke et al. [72], Bousselamti & Cherkaoui [102] evaluated the economic performance of hybrid PT-PV plants and found that the LCOE of the hybrid systems were lower than that of the standalone PT plants. Starke et al. [72], Pan & Dinter [74] and Hassani et al. [86] assessed the economic impact of hybrid ST-PV plants of and compared them to standalone PV and ST plants. The results showed that the hybrid ST-PV plants achieved lower LCOE values than the standalone ST plants, indicating that the electricity generation cost of hybrid solar thermal-PV plants is cheaper than conventional solar thermal power plants. Another advantage of a hybrid CSP-PV plant is the increase in the plant's capacity factor due to the thermal energy stored while the PV system is in production, helping to achieve a fully dispatchable solar electricity generation system. A smaller CSP solar field is achieved through the hybridization of a CSP and a PV system resulting in lower LCOE values and higher capacity factors. It was reported that the reduction of the solar field size is about 40 % for hybrid PT plants and 30 % for hybrid ST plants [72]. In general, the results from the studies showed that hybrid plants achieved lower LCOE than standalone solar thermal plants which is confirmed by Nathan et al. [88] who also reported that hybrid solar thermal plants provide more cost-effective power generation than standalone solar thermal power plants due to the opportunities of infrastructure sharing and increases in efficiency. Studies also found that the electricity generation costs of standalone PV systems were lower than hybrid CSP-PV plants due to the significantly lower capital costs of standalone PV systems [72,73]. However, the capacity factor of standalone PV systems is very low around 25 % due to its intermittent nature. In contrast, the capacity factor of hybrid CSP-PV is around 80 % and above, meaning it produces maximum power 80 % of the time or more [72]. To aid comparisons of the economic impact of hybrid CSP-PV plants, economic assessment of different types of hybrid CSP-PV plants using LFR, PT, ST and SD technologies must be modelled using similar locations, software, capacities and conditions. This should then be compared with the economic performance of standalone PT, ST, LFR, SD and PV plants using similar modelling conditions.

Ayadi & Alsalhen [75], Shboul et al. [76], Chennaif et al. [77] and Ding et al. [99] assessed the economic impact of hybrid CSP-wind plants of 1.5 MW – 80 MW. Ayadi & Alsalhen [75] used TRNSYS software for the economic assessment of a 50 MW hybrid PT-wind plant and found that the hybrid plant had a lower LCOE than that of the standalone PT plant. However, the standalone wind turbine had the lowest LCOE at 0.029 JOD/kWh compared to 0.045 JOD/kWh for the hybrid plant and 0.058 JOD/kWh for the standalone PT plant. Shboul et al. [76] assessed the economic performance of a hybrid concentrated parabolic solar dish Stirling engines (CPSD-SE)-wind plant of 1.5 MW using MATLAB. The results showed that the LCOE of the hybrid plant was higher than the standalone SD plant (CPSD-SE). This could be due to the low plant capacity of the hybrid plant and the authors reported that the LCOE would decrease at large plant capacities. Ding et al. [99] assessed the economic performance of a 80 MW hybrid PT-Wind system using numerical equations and found that the highest NPV value was achieved when the capacity ratio of the wind farm/PT is 1.91, TES is 13 hrs, solar multiple is 2.9 with an electric heater of 6 MW.Chennaif et al. [77] evaluated the economic impact of a hybrid PT/PV/Wind plant of 50 MW using a novel algorithm called Electric System Cascade Extended Analysis (ESCEA) to achieve the optimal sizing of the hybrid systems to obtain the lowest cost of electricity produced. The authors found that the hybrid PT/PV/Wind with BESS & TES had the lowest LCOE at $0.183/kWh due to the alternation of the renewable energy sources between them. This was followed by the PT-PV plant with BESS & TES at $0.210/kWh and then the PT-wind plant with BESS &TES at $0.264/kWh. Amongst the standalone systems, the PT plant with TES achieved the lowest LCOE value at $0.1963/kWh, followed by the PV with batteries at $0.2383/kWh. The wind system with batteries had the highest LCOE values ranging from $0.4 - $0.55/kWh due to the low potential of wind speed in the selected site.

Cardemil et al. [78] assessed the economic performance of a single flash and double flash geothermal plant hybridized with a PT system considering four different geothermal reservoir conditions, using Engineering Equation Solver (EES). The performance of the single and double-flash hybrid system was evaluated and compared using the Case 2 design conditions. Under these conditions, the results showed that the double flash hybrid PT-geothermal plant achieved the lowest LCOE at $56/MWh as it produced 15–25 % more power output than the single double flash hybrid system. The LCOE for the single flash PT-Geothermal plant was higher at $64/MWh, whilst standalone geothermal plants have LCOE values ranging from $60 -$205/MWh according to the literature. To improve the comparison of the economic impact of the hybrid plants and the standalone geothermal plant, the authors should model the performance of a conventional geothermal plant using similar design conditions as the single and double flash hybrid systems. Zhou et al. [79] compared the economic performance of a hybrid PT-geothermal and standalone PT and geothermal plants at 3 different locations in Australia using ASPEN-HYSYS and Excel. The results showed that the standalone PT plant had the lowest LCOE which was due to its significantly lower capital costs of $4.83 -$4.92 million/MW compared to $16.75 -$18.48 million/MW for the hybrid PT-Geothermal plant and $20 million/MW for the standalone geothermal plant. However, the hybrid PT-geothermal plant achieved a lower LCOE at $171-$177/MWh compared to $225/MWh for the standalone geothermal system due to the hybrid plant generating 2–3 % more annual electricity than the standalone geothermal plant. McTigue et al. [80] compared the performance of hybrid solar-geothermal plants, PV with battery energy storage (BES) and standalone PV systems and observed that the hybrid CSP-geothermal plant achieved a lower LCOE than the PV with BES, whilst the standalone PV system had the cheapest electricity generation costs due to its lower capital costs. It would have been useful for both Cardemil et al. [78] and Mctigue et al. [80] to compare the economic impact of the hybrid CSP-geothermal plants with standalone solar thermal plants as well as conventional geothermal plants. Tranamil-Maripe et al. [96] compared the economic performance of a hybrid PT-geothermal system with a standalone geothermal plant using Engineering Equation Solver (EES) and found that the hybrid plant achieved a lower LCOE than the standalone geothermal plant. McTigue et al. [100] compared the LCOE of a hybrid solar thermal-geothermal plant, standalone solar thermal plant and a PV with Battery Energy Storage System (BESS) using SAM software. The results showed that at storage capacities of 3 hrs and more, the hybrid plant attained the lowest LCOE, followed by the standalone solar thermal plant. The PV with BESS had the greatest LCOE due to the high cost and replacement rate of the batteries compared to thermal storage. Pramanik and Ravikrishna [69] reported lower costs, higher efficiency and greater power output as the advantages of hybrid CSP-geothermal plants compared to standalone

Table 6
Studies with economic assessment of hybrid solar thermal plants.

Reference	Platzer [71]	Starke et al. [72]	Parrado et al. [73]	Pan & Dinter [74]	Ayadi & Alsalhen [75]	Shboul et al. [76]
Type of hybrid solar thermal system	Parabolic trough-PV	Parabolic Trough-PV, Solar Tower-PV	Parabolic Trough-PV	Solar Tower-PV	Parabolic Trough-Wind	Solar Dish-Wind
Plant Capacity (MW)	50 MW PT & 75 MW PV	50 MW	50 MW	100 MW	50 MW	1.5 MW
Economic Assessment Software	Excel	SAM, TRNSYS	MATLAB, SAM	SAM	TRNSYS	MATLAB
Economic Assessment Method	LCOE, Capital costs	LCOE	LCOE	LCOE	LCOE	LCOE
Economic impact (Internal)	**LCOE Values** PT alone = €0.152/kWh PT-PV = €0.124/kWh **Capital Costs** PT alone = €324.1 Mio PV = €84.6 Mio	**LCOE Values** PT-PV = $123.2/MWh ST-PV = $152.1/MWh PT only = $128.4/MWh ST only = $154.5/MWh PV only = $91.4/MWh	**LCOE Values (2014–2050)** **Blue Map Scenario** PV alone ($/kWh) = Between 12.88 and 8.43 PT alone ($/kWh) = Between 15.29 and 9.02 PT-PV ($/kWh) = Between 14.69 and 8.57 **Road Map Scenario (2014–2050)** PV alone ($/kWh) = Between 10.74 and 7.79 PT alone ($/kWh) = Between 14.93 and 7.57 PT-PV alone ($/kWh) = Between 13.88 and 7.74	**Lowest LCOE Values** ST-PV = $0.121/kWh ST alone = $0.133/kWh	**LCOE Values** Wind Alone = 0.029 JOD/kWh PT Alone = 0.058 JOD/kWh Hybrid PT-Wind = 0.045 JOD/kWh	**LCOE Values** SD-Wind (CPSD-SE/HWT) = $0.130/kWh SD alone (CPSD-SE) = $0.0601/kWh
Economic Impact (External)	N/A	N/A	N/A	N/A	N/A	N/A

Reference	Chennaif et al. [77]	Cardemil et al. [78]	Zhou et al. [79]	McTigue et al. [80]	Guiterrez-Alvarez et al. [81]	Suresh et al. [82]
Type of hybrid solar thermal system	Parabolic Trough/PV/Wind	Parabolic Trough-Geothermal	Parabolic Trough-Geothermal	Solar Tower - Geothermal	Parabolic Trough-Biomass, Solar Tower-Biomass	Parabolic Trough - Biomass
Plant Capacity (MW)	50 MW	<30MW	n/a	5 MW	50MW	1MW – 20MW
Economic Assessment Software	MATLAB	Engineering Equation Solver (EES)	ASPEN-HYSYS, Excel	SAM, ASPEN Process Economic Analyzer V10	SAM	Numerical equations
Economic Assessment Method	LCOE	LCOE	LCOE, Capital costs	LCOE	LCOE, Capital Costs	LCOE, Capital Costs
Economic impact (Internal)	**LCOE Values** PT-PV with BESS&TES = $0.210/kWh PT-Wind with BESS & TES = $0.264/kWh PT/PV/Wind with BESS & TES = $0.183/kWh PT alone with TES = $0.1963/kWh PV with batteries = $0.2383/kWh Wind with batteries = $0.4 - $0.55/kWh	**LCOE Values** PT-Geothermal (Single Flash) = $64/MWh PT-Geothermal (Double Flash) = $56/MWh Geothermal only plants = $60 - $205/MWh	**LCOE Values** Geothermal alone = $225/MWh PT plant alone = $113 -$163/MWh Hybrid PT-Geothermal = $171 - $177/MWh **Capital Costs** Geothermal alone = $20 million/MW PT alone = $ 4.83 -$4.92 million/MW Hybrid PT-Geothermal = $16.75 -$18.48 million/MW	**LCOE Values** Hybrid ST-Geothermal = $0.125/kWh PV+BES = $0.187/kWh PV = $0.074/kWh	**LCOE Values** **<u>PT with No Biomass</u>** No TES = $0.21/kWh 10hr TES= $0.23/kWh 20hr TES = $0.25/kWh **<u>PT with medium Biomass</u>** No TES = $0.13/kWh 10hr TES= $0.17/kWh 20hr TES= $0.21/kWh **<u>ST with no Biomass</u>** No TES= $0.24/kWh 10hr TES= $0.185/kWh 20hr TES= $0.18/kWh **<u>ST with medium Biomass</u>** No TES= $0.14/kWh 10hr TES=$0.155/kWh 20hr TES= $0.17/kWh	**LCOE Values @ INR 2,500 per tonne of Biomass** **1MW Plant Capacity** Standalone CSP = INR 21/kWh Standalone Biomass plant = INR 9/kWh Hybrid PT-Biomass (24X7 operation) = INR 10.10/kWh @ 1MW **20MW Plant Capacity** Standalone CSP = INR 8/kWh Standalone Biomass plant = INR 3/kWh Hybrid PT-Biomass (24X7 operation) =INR 3.79/kWh **Capital Cost of Hybrid System** @ 1 MW = Around INR 49 @20 MW = Around INR 260
Economic Impact (External)	N/A	N/A	N/A		N/A	N/A

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Table 6 (*continued*)

Reference	Ellingwood et al. [84]	Elmadioune et al. [85]	Hassani et al. [86]	Middlehoff et al. [87]	Nathan et al. [88]
Reference	Ellingwood et al. [84]	Elmadioune et al. [85]	Hassani et al. [86]	Middlehoff et al. [87]	Nathan et al. [88]
Type of solar thermal system	Solar Tower-natural gas	Parabolic Trough-PV	Solar Tower-PV	Solar Tower- Biomass	Hybrid Solar thermal plants
Plant Capacity (MW)	80 MW	50 MW	11MW	5MW, 15MW, 30MW & 50MW	N/A
Economic Assessment Software	SAM	SAM	SAM	SAM	N/A
Economic Assessment Method	Capital cost, LCOE	LCOE, Annual savings	LCOE	LCOE	N/A
Economic impact (Internal)	**LCOE** ST plant= $271.5/ MWh Hybrid plant = $123.2/MWh Hybrid plant with flexible heat integration (FHI) = $122.7/MWh **Capacity Factor** ST plant = 30.7% Hybrid plant = 99.7% Hybrid plant with FHI = 99.7%	**Levelized Cost of Heat (LCOH)** Hybrid plant = €0.012/kWh Without hybrid plant = €0.1/kWh Annual cost savings of 43% is achieved when the hybrid plant is used instead of grid electricity. The optimal tilt angle of the PV is 32° which produces the lowest LCOE value of the PV system is €6 cent/ kWh.	Hybrid plant has a lower LCOE than standalone ST plant.	The total plant investment varies between AU$ 49.5–68.5 million and AU$ 241.1–333 million for the smallest and largest plant scenario. The LCoE levels vary from AU $96–154/MWh for the largest hybrid plant to AU$187 – 293/MWh for the smallest hybrid plant size.	Hybrid solar thermal plants offer more cost-effective power generation than is possible with the equivalent stand-alone solar thermal and combustion power plants because of the opportunities for infrastructure sharing, increases in efficiency, and greater capital utilisation.
Economic Impact (External)	N/A	N/A	N/A		N/A

Reference	Oliveira et al. [89]	Oyekale et al. [90]	Rashid et al. [91]	Sahoo et al. [92]	Pantaleo et al. [93]
Type of solar thermal system	Parabolic Trough-Biomass	Linear Fresnel-Biomass	Parabolic Trough-Natural Gas	Parabolic Trough-Biomass	Parabolic Trough-Biomass-Gas Turbine
Plant Capacity (MW)	28.5 MW	0.63 MW	140 MW	14.606 MW	2MW
Economic Assessment Software	SAM	N/A	SAM	Engineering Equation Solver (EES)	N/A
Economic Assessment Method	NPV	Investment Cost, Annual Costs, LCOE	Annual capital cost, LCOE	Capital Cost, LCOE, Payback period	LCOE, NPV, IRR
Economic impact (Internal)	**NPV** Hybrid PT-Biomass (Phoenix location) =$−22.7 million dollars Hybrid PT-Biomass (Barreiras location) =$−33.2 million dollars These negative values indicate that implementing the hybrid plant under current solar field costs and biomass prices is not economically feasible as there is no payback.	Investment Cost = €4 million Annual Costs = €181k/ year LCOE = €187/ MWh	**Annual capital cost ($/year)** Natural gas = 27,434,600 Hybrid plant without TES = 37,558,600 Hybrid plant with TES = 45,018,200 **LCOE ($/MWh)** Natural gas = 60.40 Hybrid plant without TES = 74.92 Hybrid plant with TES = 86.32	**Capital Cost (Lakhs)** Solar thermal plant = 7128 Hybrid solar thermal plant = 6875.72 Cogeneration in hybrid-solar biomass (HSB) plant = 7375.72 Polygeneration in HSB plant = 7460.72 **LCOE (Lakhs/kWh)** Solar thermal plant = 12.08 Hybrid solar thermal plant = 7.45 Cogeneration in HSB plant = 7.45 Polygeneration in HSB plant = 7.45 **Payback Period (years)** Solar thermal plant = 18.7 Hybrid solar thermal plant = 2.55 Cogeneration in HSB plant = 2.36 Polygeneration in HSB plant = 1.52	**LCOE** Hybrid plant = €140/ MWh **NPV** Hybrid plant (Rabat with high solar field size) = €14,000 k Hybrid plant (Marseille with low solar field size) = €600k **IRR** Hybrid plant (Rabat) = 25% Hybrid plant (Marseilles) = 3.7%
Economic Impact (External)	N/A	N/A	N/A	N/A	N/A

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Table 6 (*continued*)

Reference	Guccione et al. [94]	Starke et al. [95]	Tranamil-Maripe et al. [96]	Youssef et al. [97]	Sarkis & Zare [98]	Ding et al. [99]
Reference	Guccione et al. [94]	Starke et al. [95]	Tranamil-Maripe et al. [96]	Youssef et al. [97]	Sarkis & Zare [98]	Ding et al. [99]
Type of solar thermal system	Solar Tower-PV plant with supercritical CO_2 (sCO_2) power block	Parabolic Trough-PV Solar Tower-PV	Parabolic Trough-Geothermal	Parabolic Trough-PV	Solar thermal-Biomass	Parabolic Trough-Wind
Plant Capacity (MW)	100MW	N/A	30 – 60MW	4.65MW	7.945 MW – 10.249MW	80 MW
Economic Assessment Software	SAM	TRNSYS	EES	TRNSYS	Engineering Equation Solver (EES)	Numerical Equations
Economic Assessment Method	LCOE	LCOE	LCOE	Investment Cost, NPV, IRR, Discount Payback (DBP)	LCOE	NPV
Economic impact (Internal)	**DNI of 1900 kwh/(m^2/yr)** LCOE values lower than €66/MWh **DNI of 3400 kwh/(m^2/yr)** LCOE = €46/MWh	**LCOE** Hybrid PT-PV = \$121/MWh - \$133/MWh Hybrid ST-PV = \$152/MWh - \$160/MWh Hybridization can reduce the LCOE, increases the capacity factor, but the most important effect is the significant reduction on the solar field size.	**Optimal LCOE Value** Hybrid PT-Geothermal = \$81.18/MWh Standalone Geothermal = \$90/MWh	Investment Cost = €34,233 NPV = €33,000 IRR = 19% DBP = 8 years	**LCOE** Standard Configuration = \$79.34 Configuration 1 = \$79.88 Configuration 2 = \$74.95	**NPV** Highest NPV = \$27.67 million when capacity ratio of the Wind Farm/CSP is 1.91, TES is 13 hrs, SM IS 2.9 and Electric Heater is 6MW.
Economic Impact (External)	N/A	N/A	N/A	N/A	N/A	N/A

Reference	McTigue et al. [100]	Acosta-Pazmino et al. [101]	Bousselamti & Cherkaoui [102]	Zurita et al. [103]	Costa & Neto [104]
Type of solar thermal system	Solar thermal-geothermal	Parabolic Trough-PV	Parabolic Trough-PV	Solar Tower-PV with Battery Energy Storage System (BESS)	Solar Tower-Natural Gas
Plant Capacity (MW)	24MW	0.083MW	150MW	100MW	110MW
Economic Assessment Software	SAM	TRNSYS	SAM	TRNSYS	SAM
Economic Assessment Method	LCOE	Investment cost, Payback period, Annual electricity savings	LCOE	LCOE	LCOE
Economic impact (Internal)	**LCOE (\$/kwh) for storage of 3hrs** Hybrid plant = 0.081 ± 0.011 PV+BESS = 0.148 ± 0.066 Standalone CSP = 0.096 ± 0.011 **LCOE (\$/kwh) for storage of 10hrs** Hybrid plant = 0.091 ± 0.011 PV+BESS = 0.254 ± 0.130 Standalone CSP = 0.093 ± 0.011	**Investment Cost** Hybrid PT-PV plant = \$80,841 ST plant = \$69,342 **Annual Electricity Savings** Hybrid PT-PV plant = \$1,540 ST plant = 0 **Payback Period** Hybrid PT-PV plant =4.32 years ST plant = 3.83 years	Hybrid plant has a lower LCOE than the standalone PT system. Increasing the PV share of the hybrid plant results in a huge reduction in the LCOE but achieves lower electricity generation and less flexibility to dispatch electricity from day to night.	Hybrid plant with BESS = \$89.19/MWh Hybrid plant without BESS = \$77.22/MWh	**LCOE** Hybrid plant = \$13.1cent/kWh Standalone ST plant = \$14.4 cent/kWh
Economic Impact (External)	N/A	N/A	N/A	N/A	N/A

geothermal plants. However, the authors note that other studies have found that the LCOE of the hybrid system was higher than a standalone geothermal plant, indicating that the cost of electricity generation is highly sensitive to the location and availability of resources.

Guiterrez-Alvarez et al. [81], Suresh et al. [82], Middlehoff et al. [87], Oliveira et al. [89], Oyekale et al. [90], Sahoo et al. [92], Pantaleo et al. [93] and Sarkis & Zare [98] assessed the economic impact of hybrid solar thermal-biomass plants ranging from 0.63 MW to 50 MW using SAM and EES software. Guiterrez-Alvarez et al. [81] compared the LCOE of 50 MW hybrid PT-biomass, ST-biomass plants, standalone PT and ST plants and found that the hybrid plants achieved lower LCOE values than the standalone PT and ST plants. The results also showed that both the conventional and hybrid PT plants without thermal energy storage (TES) had lower electricity generation costs than the conventional and hybrid ST plants with no TES. However, when the conventional and hybrid solar thermal plants were integrated with 10 hrs and 20 hrs TES, the ST plants achieved lower LCOE values than the PT plants. A key disadvantage of the hybrid plants is its higher GHG emissions compared to standalone solar thermal plants which is a trade-off in order to achieve lower electricity generation costs. There is also contention regarding the utilization of land for the growth of high energy crops for use as biomass which has led to the food versus fuel debate. The use of cellulosic biomass such as wood wastes, straws, animal wastes and bagasse has reduced some of these concerns. However, a steady supply of biomass fuel must be ensured for the duration of the lifespan of a biomass/hybrid plant typically around 25 years. Another drawback is the plant capacity which is often restricted between 5 and 50 MW due to the cost and steady supply of biomass [69].

Suresh et al. [82] also compared the economic impact of a hybrid PT-biomass plant with standalone solar thermal and biomass plants but with lower capacities ranging from 1 MW – 20 MW. The results revealed that the hybrid plant outperformed the standalone solar thermal plant achieving a LCOE of INR10.10/kWh at 1 MW and INR 3.79/kWh at 20 MW compared to INR 21/kWh at 1 MW and INR8/kWh at 20 MW for the standalone solar thermal plant. However, the conventional biomass plant achieved the lowest electricity generation costs at plant capacities of 1 MW-20 MW due to their significantly lower capital costs than standalone solar thermal plants and hybrid plants. In addition, the LCOE is highly sensitive to the capital costs of the systems as well as the biomass costs, loan and interest rates. The study showed that as the plant capacity increased from 1 MW to 20 MW, the capital costs of the hybrid plant rose from INR49 to INR260. However, the rise in the plant capacity also resulted in an increase in the efficiency of the power block from 20 % to 30 %, a decrease in the solar field area from 10,000 m^2/MW to 5,000 m^2/MW as well as a reduction in the amount of biomass required from 3,400 tonnes/MW to 1,600 tonnes/MW.

Ellingwood et al. [84], Rashid et al. [91] and Costa & Neto [104] evaluated the economic performance of solar thermal plants hybridised with natural gas boilers ranging from 80 MW to 140 MW using SAM software. Ellingwood et al. [84] compared the LCOE of a hybrid plant, standalone ST plant and a hybrid plant using flexible heat integration (FHI) and found that the hybrid plant with FHI attained the lowest LCOE, followed by the hybrid plant and then the standalone ST plant. The results from the studies showed that the hybrid plants achieved lower LCOE than standalone solar thermal power plants. However, hybrid plants with TES had higher LCOE than hybrid plants without TES due to the cost of the TES [91].

In general, the studies found that hybrid solar thermal plants achieved lower electricity generation costs than conventional solar thermal plants especially when the solar thermal plants were hybridized with PV, wind or biomass. The lower LCOE of the hybrid plants is due to the increased capacity factor achieved through thermal energy being stored while the renewable energy source such as PV or wind is in production. The solar thermal plant usually operated during the day time to fill up any gap in the hybrid plant's gross energy production. The key advantage of a hybrid solar thermal plant is the reduction in the size of the CSP solar field as a result of hybridization with a renewable energy source which increases its capacity factor and lowers its LCOE. The electricity generation costs of CSP-geothermal depended on the type of hybrid configuration used as observed by Cardemil et al. [78] who found that the double flash PT-geothermal configuration resulted in a lower LCOE value than the single flash configuration due to it delivering up to 25 % more power output under the same operating conditions as a single flash system. A wide range of hybrid solar-geothermal configurations can be used including single flash, double flash, binary, solar superheating, solar preheating and geothermal preheating which impacts on the LCOE of the hybrid plant. To compare and identify the hybrid systems with the best economic performance, CSP hybridized with PV, wind, biomass and geothermal can be simulated using the same modelling conditions for each of the different types of hybrid systems.

7. Future work

This section highlights the areas for future research in the economic assessment of conventional solar thermal power plants, integrated solar combined cycle plants and solar thermal plants hybridized with other renewable energy technologies. A number of the studies in the reviewed literature performed design optimization of the solar thermal power plants to achieve the least LCOE value. However, the majority of the design optimization were based on PT and ST technologies, with very few studies optimizing the design parameters of LFR or SD plants to obtain their optimal LCOE values. Therefore, there's a need for more design optimization studies of LFR and SD technologies that focus on their economic performance to enable comparisons with PT and ST technologies. Furthermore, future work should focus on the simulation of different solar thermal technologies with their thermo-economic performance compared using similar design and modelling conditions to enable more accurate comparisons to be made on the economic performance of different solar thermal technologies. LCOE was the most dominant metric used in the economic assessment of different solar thermal technologies in the reviewed literature, with a limited use of other financial metrics including NPV, IRR, revenues and payback period. This highlights the need for future studies to include these metrics in their analysis in order to provide a more comprehensive economic assessment of solar thermal technologies and to enable comparison of their economic performance with other types of renewable energy systems. In general, LFR and SD were the least studied solar thermal technologies amongst the reviewed literature on the economic performance of solar thermal power plants. Therefore, more studies should be directed on the economic impact of LFR and SD technologies with varying capacities to increase the economic performance data available for these technologies, enabling effective comparisons to be made with other types of solar thermal technologies and renewable energy systems. There were limited studies in the literature on the current economic impact of ISCC plants with capacities of 250 MW and above, with very few studies conducting comparative analysis of the economic impact of LFR, PT and ST integrated with CCGT. Therefore, future work should focus on the comparative analysis of the economic performance of the LFR, PT and ST integrated with CCGT with capacities above 250 MW using homogeneous capacities, locations, design and modelling conditions.

Additional effort should also be directed in reducing the costs of the solar field of CSP plants by focusing more research on inexpensive materials with low environmental and economic impact that can be used for the components of the solar field to reduce the LCOE of standalone solar thermal plants and make them competitive with other renewable energy technologies. In addition, continued research is required on reducing the thermal and optimal losses of solar thermal collectors to increase their efficiency leading to higher energy generation and lower LCOE. Studies have found that PV plants with BESS resulted in higher LCOE compared to hybrid solar thermal plants and standalone solar thermal systems due to the high cost and replacement rate of its batteries compared to thermal storage. Future research is required in reducing the cost of BESS in order to make it competitive to be used with PV systems enabling the dispatchability of the stored energy to be used during the night or times of low solar irradiation. More studies should also be directed on the economic performance of supercritical CO_2 power block in solar thermal power systems integrated with an electric heater as it has been shown that such system decreases the LCOE of the plant compared to traditional steam cycles. In terms of integrated solar combined cycle (ISCC) plants, DSG-ISCC-ET system was found to achieve 20 % lower LCOE than DSG-ISCC plant. More research should therefore focus on the economic and thermal performance of DSG-ISCC-ET in reducing energy generation costs of ISCC plants as it has demonstrated superior thermo-economic performance than combined cycle gas turbine (CCGT) and DSG-ISCC plants. Prospective research should also be directed on improving plant efficiency through various methods such as hybridisation of solar thermal power plants with renewable energy sources with the inclusion of DSG technology. Several studies have assessed the performance of mainly PT plants integrated with DSG technologies, however, future studies should focus on the economic impact of DSG integrated with other solar thermal technologies such as ST and LFR to identify the ones with the least energy generation costs. Future development in solar thermal power plant includes the integration of nanoparticles in the base fluid to enhance its thermophysical properties. Commonly used base fluids like water, ethylene glycol and thermion have low thermal conductivity and lower heat transfer rates which can be raised with the inclusion of nanoparticle suspension in them resulting in increased thermal efficiency which could lead to LCOE reduction of solar thermal plants. Only one study in the reviewed literature assessed the economic impact of LFR plants hybridized with other renewable energy sources. Most of the studies focused on hybrid PT and ST plants. However, the capital cost of LFR plants tend to be less expensive than PT and ST plants which may lead to hybrid LFR plants achieving lower LCOE than hybrid PT and ST plants. Therefore, future research is required on the economic performance of LFR plants hybridized with other renewable energy technologies, in order to understand their economic impact and enable their comparison with hybrid PT and ST plants, standalone solar thermal plants and other renewable energy technologies.

8. Conclusion

This paper investigated the economic impact of solar thermal power plants assessed in the literature. Several factors that impact on the economic performance of solar thermal power plants were identified including the type of solar thermal technology, DNI values, plant capacity, cooling method and the inclusion of thermal energy storage. Studies have shown that the thermo-economic performance of solar thermal power plants are strongly dependent on the DNI values of the location of the plants, with higher DNI levels resulting in greater electricity generation and improving the economic feasibility of the plants. The inclusion of TES in solar thermal power plants affects its economic performance resulting in higher capital costs but lower LCOE and shorter payback periods than plants without TES. This is due to the flexibility of plants with TES where energy can be supplied at different times especially when electricity prices are highest thus obtaining higher revenues. TES also increases the capacity factor of a solar thermal power plant resulting in reduced LCOE, improving the economic feasibility of the plant. A few studies compared the economic performance of different types of solar thermal technologies in the same location with similar design conditions. The results of these studies suggest that at smaller capacities of 10 MW, PT technology achieved the lowest LCOE, followed by ST and then SD technology while at larger capacities of 100 MW and above, ST plants tend to have lower LCOE values than PT plants. This can be attributed to ST technology have a higher concentration ratio, optical efficiency and capacity factor resulting in greater annual electricity generation than PT technology. There is a need for more comparative studies on the economic performance of different solar thermal technologies including LFR of various capacities using similar design and modelling conditions which was lacking in the reviewed literature. Some of the reviewed studies optimized the design parameters such as the solar multiple and thermal storage hours of the plants to achieve the least LCOE. However, other studies did not perform design optimization of the plants, hence the optimal LCOE of those plants may not have been achieved. When a design optimization of PT and LFR plants of 50 MW was performed, the simulations showed that the optimal LCOE achieved by the LFR plant was lower than the PT plant. There were very few studies in the reviewed literature that conducted design optimization of LFR plants to achieve their optimal economic performance. Hence, further studies are required in this area to broaden the understanding of the economic impact of LFR and enable their comparison with other types of solar thermal technologies.

The economic performance of integrated solar combined cycle (ISCC) plants were reviewed in this paper and it was found that ISCC plants had lower LCOE than conventional solar thermal power plants but higher than combined cycle gas turbine (CCGT) plants. However, ISCC plants were more cost-effective than CCGT plants when the carbon price was considered and when the cost of natural gas was above a certain price. ISCC plants in locations with high DNI values have higher capacity factors resulting in increased annual electricity generation and lower LCOE. The economic performance of ISCC plants is dependent on the DNI values as well as the price of natural gas. The financial performance of DSG-ISCC plants were compared with CCGT plants, with the results showing that although the capital cost of the DSG-ISCC plant was higher than the CCGT plant, its LCOE was lower than the CCGT plant due to its significant annual financial benefits resulting in shorter payback period than the CCGT plant. One of the studies compared the thermo-economic performance of a DSG-ISCC-ET plant with a DSG-ISCC and a CCGT plant and found that the DSG-ISCC-ET plant achieved higher solar thermal share, net power output, exergy efficiency, fossil-fuel savings as well as lower LCOE than the DSG-ISCC and CCGT plants. Future studies should focus on novel ISCC systems including the DSG-ISCC-ET system that has demonstrated superior thermo-economic performance than CCGT and DSG-ISCC plants. The economic impact of hybrid solar thermal plants was also considered and the studies found that in general, hybrid solar thermal power plants achieved lower LCOE than standalone solar thermal plants. However, standalone renewable energy systems as solar PV, wind turbines and biomass plants had lower electricity generation costs than hybrid solar thermal power plants due to their significantly cheaper capital costs. Further studies should be conducted on the economic performance of hybrid solar thermal plants by simulating the different types of hybrid plants using the same software, capacity and modelling conditions in order to compare their economic impact effectively. LCOE and capital costs were the dominant financial metrics used in the reviewed literature, with few studies using revenues, payback period, life cycle costs and IRR in the economic assessment of the solar thermal power plants. Therefore, prospective studies on the economic performance of solar thermal power plants should include these metrics in order to provide a more comprehensive financial assessment of the plants and enable their economic performance to be compared with other renewable and non-renewable energy systems.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

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