**TECHNOECONOMIC OPTIMIZATION OF HYBRID PV–CSP–TES SYSTEMS WITH sCO₂ BRAYTON CYCLES ACROSS DIVERSE GEOGRAPHIC LOCATIONS**

Abstract

Hybridizing photovoltaic (PV) and concentrated solar power (CSP) with thermal energy storage (TES) offers a pathway to dispatchable, reliable, and low-cost electricity. This study presents an optimization and techno-economic analysis of a hybrid photovoltaic-concentrated solar power (PV-CSP) system integrated with thermal energy storage (TES) and a supercritical CO₂ (sCO₂) Brayton cycle. Hourly energy flows were simulated across eleven U.S. locations for grid-tied and isolated configurations. The results reveal that geographic variation significantly impacts system economics, with high Global Horizontal Irradiance (GHI) locations such as El Paso, TX and Otero County, NM achieving the lowest Levelized Cost of Electricity (LCOE) values ($0.081/kWh for grid-tied and $0.109/kWh for isolated systems). Parametric sweeps highlight the trade-offs between subsystem sizing and economic performance, demonstrating diminishing returns in LCOE beyond moderate TES and CSP capacities. Grid-tied systems generally outperform isolated configurations at moderate reliability levels. However, the LCOE of isolated systems become competitive when >90% load satisfaction is required. Additionally, TES capacity plays a crucial role in reducing PV curtailment, improving system efficiency by capturing excess solar generation. This analysis provides actionable insights into optimal design strategies for hybrid PV-CSP-TES systems tailored to specific geographic and operational contexts. By addressing key challenges in subsystem integration, component sizing, and reliability thresholds, this work advances the deployment of cost-effective, dispatchable alternative energy solutions capable of supporting 24/7 power generation.

INTRODUCTION

The growing global demand for low-cost energy sources has driven significant interest in solar power technologies, yet the intermittency of solar irradiance presents a major hurdle for grid integration and reliability. Energy storage can address this challenge by time shifting solar resource to better align with energy demands. Lithium-ion batteries have emerged as a viable solution for short-duration energy storage and rapid load management, however, their limited lifespan, reliance on rare-earth minerals, and high costs hinder their applicability for long-duration dispatch [1]. In regions with high solar PV penetration, the typical 8-9 hour generation window and 15-16 hour absence of sunlight are driving the need for low-cost, reliable long-duration energy storage (LDES) solutions that can store and dispatch solar energy for over 10 hours. These challenges and need areas have prompted investigation of improved solar energy systems with low cost long duration energy storage.

*Introduce what PV and Solar technologies are… Quick breakdown of benefits and drawbacks. …………. Setup the next paragraph succinctly by highlighting how PV is cheap during day and CSP has great low cost LDES. CSP is expensive. PV alone doesn’t address nighttime loads.*

Hybrid photovoltaic-concentrated solar power systems coupled with thermal energy storage represent a promising alternative by combining the low-cost daytime electricity generation of PV solar with the dispatchability and low-cost of thermal energy storage inherent to CSP [2]. These systems present promising reliability and economics for both front-of- and behind-the-meter applications [3-5] ………*Joe Shmoe et al. found…. Taylor et al found…*

Despite the promise of hybrid solar energy systems, A B and C reasons why it could be improved… Research efforts are therefore focused on improving the efficiency and cost of CSP-TES systems through advanced power cycles and storage media. For example, traditional TES systems using molten salts face limitations regarding thermal stability, material compatibility, and parasitic energy losses, particularly over extended storage durations, sparking increased interest in solid media TES systems [11]. Further, supercritical CO₂ Brayton cycles, which can reach higher thermal efficiencies than steam Rankine cycles, potentially >50%, have gained attention in the context of CSP-TES systems. This technology is well-suited for hybridization, as it operates best at high temperatures compatible with CSP and can ramp quickly to complement PV.

Despite these advances, the optimal integration and operation of hybrid PV-CSP-TES systems with sCO₂ Brayton cycles remain largely unexplored, particularly regarding component sizing, geographic deployment strategies, and grid-interaction tradeoffs. Specifically, many studies focus on optimizing the performance of sCO₂ cycles within specific CSP configurations without considering the integration with PV or the impact of geographic variability. This limits understanding of where such hybrids are most favorable or how they should be sized under different solar resource conditions. Furthermore, most analyses have not explicitly included a power block cooling subsystem in the model, an important aspect of sCO₂ cycles, which can significantly affect overall performance. Traditional CSP plants use wet cooling or dry coolers to reject waste heat, which can be challenging and costly in arid high-sun regions [12]. Hybrid designs offer novel ways to supply cooling. Excess PV electricity can drive a refrigeration cycle to produce ice, effectively storing cold for later use in condensing the CO₂ working fluid. This approach reduces or eliminates water use and allows the power cycle to operate at a lower temperature sink than ambient air.

To address these challenges, this study presents a techno-economic analysis of a hybrid solar thermal energy storage system, integrating PV panels for ice production and daytime load management, a CSP collector for harnessing and storing solar energy as heat, and an sCO₂ power block for converting thermal energy back to electricity. Using a Python-based model and Typical Meteorological Year data from the National Solar Radiation Database (NSRDB) [13], this study investigates the system's performance across various U.S. geographical locations and operational scenarios, capturing the interactions between PV, CSP, TES, and ice-based cooling. A parametric analysis is performed across 11 different U.S. locations representing a spectrum from high-DNI deserts to low-solar Appalachian climate. For each scenario, the model optimizes component sizes in terms of power and energy capacities to minimize LCOE for a given fraction of load met. The trade-off between cost and load coverage is analyzed, identifying optimal designs at 50%, 85%, and other load met targets. By modeling hourly energy dispatch under real meteorological conditions, this work identifies location-specific LCOE minima for grid-tied vs. isolated configurations, providing actionable strategies for deploying 24/7 alternative power systems that balance dispatchability and economic viability.

MethodS

**System Description**

The system architecture includes a PV array, a CSP parabolic collector, TES unit, and a sCO₂-based Brayton power block for electricity generation. Ice production for cooling is enabled using either excess PV electricity or grid electricity to provide a heat sink for the sCO2 Brayton cycle. Two configurations are evaluated: (1) grid-tied, in which grid power can supplement unmet demand and serve ice loads, and (2) isolated, where the system operates independently of grid support.

**Annual Performance Analysis**

1. Solar Resource and Climate Inputs

An annual performance analysis was conducted to estimate the hourly production from the CSP and PV fields, TES charge state, and grid electricity requirements and cost. CSP and PV performance were evaluated using 2020 solar irradiance availability data from the National Renewable Energy Laboratory’s National Solar Radiation Database for the location of interest. The hourly electricity output of the PV system was estimated with PVLib’s Python library using the Direct Normal Irradiance (DNI), Diffuse Horizontal Irradiance (DHI), and Global Horizontal Irradiance (GHI) values from the NSRDB data.

1. PV Performance Modeling

The PV module used is the Canadian Solar CS5P\_220M (2009), with parameters from the Sandia Module Database. The plane of array irradiance is calculated from the angle of incidence (AOI), SVF (sky view factor) and ρ (ground albedo) to determine the total solar irradiance incident on the tilted PV modules (1). The cell temperature estimation, based on the Sandia Array Performance Model, was used to account for the impact of ambient conditions on module performance (2).

|  |  |  |
| --- | --- | --- |
|  |  | (1) |

|  |  |  |
| --- | --- | --- |
|  |  | (2) |

The electrical energy produced by the PV system was converted to thermal energy for charging the TES assuming a fixed heater efficiency (𝜂ℎ𝑒𝑎𝑡𝑒𝑟) of 99%.

1. CSP Performance Modeling

The CSP output was estimated based on the DNI and total collector area . The collection fraction equation is calculated from the transmission coefficient (τ), acceptance factor (f), and other optical and thermal factors.

The total thermal power delivered is determined by the incident solar flux () and corrected for optical performance and thermal losses.

|  |  |  |
| --- | --- | --- |
|  | ) | (3) |

|  |  |  |
| --- | --- | --- |
|  |  | (4) |

|  |  |  |
| --- | --- | --- |
|  |  | (5) |

The total solar power captured by CSP collectors (9) determined by incident solar flux (), accounting for radiative losses from the collector surface (7) and pipe transmission losses (8).

|  |  |  |
| --- | --- | --- |
|  |  | (6) |
|  |  | (7) | |

|  |  |  |
| --- | --- | --- |
|  |  | (8) |

|  |  |  |
| --- | --- | --- |
|  |  | (9) |

**TES Dispatch Logic**

The energy balance model operates under two scenarios to evaluate the performance of the model under varying degrees of autonomy. In the grid-tied configuration, any portion of the load or ice production not met by the combined output of PV and CSP is supplemented by the grid, while in the isolated configuration, the load and ice production can be met solely by stored energy from TES and direct generation from PV and CSP. For both configurations, the system first directs available PV output towards producing ice for the power block’s low-temperature reservoir. The energy requirement for making ice for any hour is determined as the amount of ice needed to discharge 1 kWh of heat from the power block. Therefore, the hourly ice requirement is determined from the amount of heat added to the TES in that hour, which is initially the thermal input from the CSP weighted by the thermal-to-electric efficiency, defined as the fraction of thermal energy converted to electricity by the sCO₂ Brayton cycle, and the round-trip efficiency, which represents the ratio of electricity recovered from the ice storage system per unit of electricity used to produce it; both efficiencies vary with the ambient temperature of the location of interest.

Following ice production, remaining PV then goes to meeting the load based on the TES dispatch logic. The system first calculates the power block discharge efficiency based on the ambient temperature, then checks if the stored energy exceeds a minimum threshold, which includes a fixed minimum depth of discharge (DOD), and the minimum TES output, which is determined by the power block turn down limit, converted to thermal energy. If above this threshold, the system determines the maximum possible discharge and TES output, which is set based on the load and available PV energy. If the sum of PV excess and the minimum TES output is less than the load, TES output is increased to meet the remaining load, up to the maximum output as specified by the power block rating. If PV plus minimum TES output exceeds the load, TES output is set to the minimum, and excess PV is recorded. When stored energy is below the threshold, no energy is discharged from TES, and PV is used to meet the load as much as possible.

If the PV generation exceeds the immediate load requirements, the surplus energy can be utilized to charge the TES and/or produce more ice. When surplus PV adds heat to the TES, additional ice production is needed for the eventual discharge of that heat through the power cycle. If the TES is not fully charged, surplus PV is allocated as follows: a) 100% to TES with ice production energy supplied by the grid in a grid-tied configuration, or b) x% to TES and y% to ice production in an isolated configuration. If the TES is fully charged, surplus PV is curtailed. Electricity sourced from the grid for ice-production is tracked, costed at $0.03/kWh, and incorporated as an annual cash flow in the TEA analysis.

Any load unsatisfied by the solar generation is, in the grid-tied configuration, met by grid electricity, or unmet, for the isolated configuration. It is noted that the energy directly supplied to the load by the grid is not counted towards the annual energy throughout of the alternative energy system, therefore the cost of that electricity is not costed in the annual cash flow.

**Techno-economic Analysis**

System costs are modeled using a discounted cash flow framework with a matching 30-year project life and analysis period. The levelized cost of energy (LCOE) is computed as:

|  |  |
| --- | --- |
|  | (8) |

where ​ is the net present value of the annual revenue requirement, is the residual value of capital assets at year 30, and ​ is annual electricity delivered to the load.

TABLE I

Capital Expenditure and O&M Costs by Subsystem

|  |  |  |
| --- | --- | --- |
| Component | CAPEX | O&M Cost |
| PV Array | $890/kW | $0.116/kW-year |
| CSP Collector | $85/m2 | $0.125/m2-year |
| TES System | $3.70 / kWhₜₕ | $0.117/kW-year |
| Power Block | $3000 / kW | $0.110/kW-year |
| Grid Power | $0.089/kWh | $0.123/kW-year |

Capital expenditure and operations and maintenance costs are shown in Table I for each subsystem. Depreciation is handled via a MACRS 7-year schedule, and financing assumptions include an 8% nominal interest rate, 2.8% inflation, and a weighted average cost of capital (WACC) derived from a 50/50 debt-equity split. Parametric sweeps are conducted to evaluate sensitivity to each component’s size and its impact on overall cost and performance and identify optimal system sizes based on overall load met percentage.

Results & DIscussion

**Location-Based LCOE Performance**

To assess the influence of geography on system economics, the system was simulated and optimized at eleven U.S. locations. Table 2 summarizes the lowest achievable levelized cost of energy (LCOE) for both grid-tied and isolated systems under two performance thresholds: minimum 50% load met and a fixed 85% load met (LMP), shown in Fig. 1.

TABLE II

Minimum LCOE Values For Various Geographical Locations

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Location | Lowest LCOE for LMP > 50% - Gridtied ($/kWh) | Lowest LCOE for LMP > 50% - Isolated ($/kWh) | LCOE for 85% LMP – Gridtied ($/kWh) | LCOE for 85% LMP – Isolated ($/kWh) |
| Page, AZ | 0.084 | 0.116 | 0.146 | 0.149 |
| Denver, CO | 0.089 | 0.125 | 0.151 | 0.157 |
| Clearwater, FL | 0.082 | 0.117 | 0.151 | 0.155 |
| Las Cruces, NM | 0.081 | 0.110 | 0.141 | 0.143 |
| El Paso, TX | 0.081 | 0.109 | 0.141 | 0.140 |
| Oxnard, CA | 0.082 | 0.117 | 0.151 | 0.158 |
| Otero County, NM | 0.080 | 0.111 | 0.141 | 0.145 |
| Sierra Vista, AZ | 0.080 | 0.114 | 0.152 | 0.154 |
| Tucson, AZ | 0.081 | 0.112 | 0.142 | 0.146 |
| New Martinsville, WV | 0.099 | 0.143 | 0.181 | 0.187 |
| Oceanside, CA | 0.089 | 0.123 | 0.156 | 0.158 |

A graph of different colored bars

AI-generated content may be incorrect.

|  |
| --- |
| Fig. 1. Levelized cost of electricity (LCOE) comparison between grid-tied and isolated system configurations across eleven U.S. locations. |

Geographic variation in solar resource and ambient temperature drives clear differences in optimal system economics. Arid, high-DNI locations such as El Paso, TX and Otero County, NM yielded the lowest LCOEs in both configurations, benefiting from favorable solar availability for both PV and CSP production. In contrast, lower-latitude locations such as Clearwater, FL exhibited moderate increases in LCOE, attributed to reduced DNI, likely influenced by higher atmospheric moisture levels that promote greater cloud cover. The cost gap between grid-tied and isolated systems ranged from $0.02–$0.05/kWh at the optimal point, narrowing at higher load-met targets. Notably, Tuscon, AZ, Las Cruces, NM, and El Paso, TX exhibited near parity in the two configurations at 85% load met, suggesting that under optimal design, isolated systems can achieve similar performance in solar-rich environments for high LMPs.

**Component Sizing and System Design**

The relative sizing of PV, CSP, and TES subsystems significantly impacts both system performance and cost. To explore these design trade-offs, parametric sweeps were conducted at each location, varying CSP collector area, PV capacity, TES capacity, and maximum hourly TES output (Fig. 3). Results reveal that LCOE increases nonlinearly with increasing load met percentage (LMP), with diminishing returns beyond moderate coverage. Across all sites, the LCOE rises gradually from 50% to 70% load met, followed by sharper increases as the system is sized to meet near-total annual demand.

This trend reflects the growing marginal cost of generation and storage capacity required to meet rare but extreme operating conditions- such as extended cloudy periods or high-cooling-demand days. For instance, in Las Cruces, NM, LCOE rises from $0.081/kWh at 55% LMP to over $0.140/kWh at 85% LMP.

Similar behavior is observed in isolated systems, where the absence of grid backup necessitates substantial oversizing of both TES and solar input (PV, CSP capacity) to maintain reliability. Grid-tied systems benefit from access to low-cost electricity ($0.03/kWh) to supplement both load demand and ice production. This enables designs with relatively modest TES and CSP capacities while maintaining operation of the power block and its cold reservoir, enabling lower LCOEs at intermediate reliability thresholds. However, as the required load coverage by RES approaches > 80-90%, the advantage of grid interconnection diminishes because nearly all demand must be supplied internally. Notably, at very high LMP (>90%), isolated systems appear to become more cost-effective than grid-tied ones. In this regime, although a grid-tied system could theoretically operate in the same manner as an isolated system of the same configuration, its dispatch logic continues to prioritize maintaining full power block operation, in particular continuous ice production to support the low-temperature reservoir, even when internal generation is insufficient. This results in additional costs, either through oversizing the TES or CSP or drawing more grid power to simultaneously satisfy the load and ice requirements. By contrast, isolated configurations, under the constraint of no external grid support, defer ice generation until after load and TES needs are met. This distinction in the ice production strategy and resource allocation becomes increasingly consequential in the high reliability regime, where grid-tied systems are penalized by their rigid concurrent load and ice generation requirements.

Figure 3 illustrates mean LCOE as a function of individual subsystem size (TES capacity, PV capacity, and CSP collector area), with shaded regions denoting the full range of parametric outcomes across the dataset. TES capacity provides the most consistent economic benefit at small-to-moderate scales, particularly for isolated systems, due to its ability to shift solar energy to later hours. However, returns diminish sharply and moderately beyond around 2 ×105 kWhₜₕ for isolated and grid-tied systems, respectively.

A graph of different colored lines

Description automatically generated

|  |
| --- |
| Fig. 2. Levelized cost of electricity (LCOE) as a function of load met percentage across twelve U.S. locations, comparing grid-tied and isolated system configurations. LCOE values are binned in 5% intervals to reduce noise and highlight overall trends. |

A graph showing the amount of energy

AI-generated content may be incorrect.

|  |
| --- |
| Fig. 3. Mean LCOE as a function of TES capacity (left), PV capacity (center), and CSP collector area (right) for grid-tied and isolated configurations. Shaded regions represent the range of system LCOEs observed across the parametric design space. Isolated systems exhibit greater sensitivity to component oversizing, particularly in PV and CSP, while grid-tied systems maintain lower and more stable LCOEs due to access to supplemental grid power. |

For PV, Figure 3 shows that isolated system LCOE initially decreases with increasing capacity but rises again due to rising capital costs and curtailment. Grid-tied systems exhibit a flatter LCOE trend with increasing PV capacity, reflecting their ability to make more effective use of PV overgeneration. Grid-tied configurations can draw on the grid to satisfy ice production and power block demands when PV supply is insufficient, reducing the sizing pressure on other subsystems. Isolated systems, on the other hand, must split available PV between TES charging and meeting load, which limits how much added PV capacity can improve performance and leads to sharper cost increases when oversized. Similarly, LCOE increases uniformly with CSP collector area, especially in isolated cases, as CSP incurs high capital cost and becomes viable only when paired with significant TES capacity.

To explore sizing interactions, Figures 4a and 4b present contour plots of LCOE and load met percentage, respectively, as functions of TES capacity and CSP fraction for the Page, AZ grid-tied system. The optimal technoeconomic region lies in the lower left quadrant, where TES capacity is moderate and CSP fraction remains below 0.2. In this region, LCOE is minimized (<$0.08/kWh) while still achieving 45–60% load coverage. As systems move toward the upper right quadrant -representing larger TES and CSP components - load met percentage increases to >90%, but LCOE rises steeply due to added capital cost and diminishing marginal benefit.

A green and yellow gradient

AI-generated content may be incorrect.

Fig. 4a Contour plot of LCOE as a function of thermal energy storage capacity and CSP fraction for Page, Arizona.

A yellow and purple gradient

AI-generated content may be incorrect.

Fig. 4b Contour plot of load met percentage as a function of thermal energy storage capacity and CSP fraction for Page, AZ.

Curtailment analysis further reinforces the role of TES in system efficiency. As shown in Figure 5a and b, average annual PV curtailment across all sites decreases with increasing TES capacity, for both grid-tied and isolated configurations. The largest reductions in curtailment occur at lower TES capacities, while the rate of improvement diminishes at higher capacities. This suggests that while storage is valuable for capturing excess PV output, over-sizing TES beyond this threshold offers limited additional benefit, with diminishing returns occurring beyond TES capacities of 2 × 105 kWhₜₕ.

|  |  |
| --- | --- |
| A graph of different colored lines  AI-generated content may be incorrect. |  |

Fig. 5a and 5b. Impact of TES capacity on PV curtailment across all locations studied. As TES capacity increases, average annual PV curtailment decreases uniformly for all sites, indicating improved utilization of solar generation through increased thermal storage.

Figure 6 compares average curtailment across all study locations for grid-tied and isolated configurations and shows that grid-tied systems consistently exhibit lower curtailment (2–3%) compared to isolated systems (4–5%), despite neither system exporting power to the grid. This difference arises because, in grid-tied configurations, surplus PV can be directed entirely to TES when the load is already met, while any remaining ice production energy requirement can be drawn from the grid. In isolated systems, however, surplus PV must be split between charging TES and producing ice, since no grid backup is available. This constraint in the isolated case necessitates larger PV arrays to ensure reliability, which in turn leads to greater daytime oversupply and curtailment. The grid’s primary role is therefore not in directly serving the load, but rather of relieving the system of the need to dedicate PV to ice production, enabling more efficient use of the available PV and reducing curtailment.

A screen shot of a graph

AI-generated content may be incorrect.

Fig. 6 Comparison of average PV curtailment between grid-tied and isolated configurations at the 85% load-met case.

**Performance Case Study – Page, AZ**

To visualize system operation over multiple days, a case study was performed for the grid-tied and isolated configurations in Page, Arizona. Hourly behavior was simulated over a representative four-day period (April 15-19) using 2020 meteorological data (Fig. 7). Table 3 shows the ratings of each subcomponent in grid-tied and isolated configurations for this case study.

TABLE III

|  |  |
| --- | --- |
| Component | Rating |
| PV Array Capacity | 4,545,454 W |
| CSP Collector Area | 13,636 m2 |
| TES Capacity | 90,917,272 Whₜₕ |
| Max TES Output | 1,000,000 W |
| Electrical Load | 1,000,000 W |

System Component Ratings for the Page, AZ Case Study

A screenshot of a graph

AI-generated content may be incorrect.

|  |
| --- |
| Fig. 7 Hourly energy balance comparison over a three-day period in Page, Arizona for the grid-tied (left) and isolated (right) system configurations at 85% load met. Top row: Energy supply to load by source, showing the role of PV, TES, and grid power (grid-tied only). Middle row: TES state-of-charge, PV generation, and CSP output alongside DNI. Bottom row: Ice production and PV excess behavior. In the grid-tied case, grid electricity supplements ice production when PV is insufficient, enabling more efficient use of later PV for TES charging or load supply. The isolated system lacks this flexibility, leading to more frequent curtailment of excess PV. |

In both configurations, PV and TES work in tandem to meet daytime load. TES is typically charged in the afternoon when PV and CSP output are abundant, and discharged in the evening or early morning when solar resources are unavailable. However, the two configurations diverge in terms of system flexibility and energy allocation strategy. In the grid-tied system, the availability of grid electricity allows for smoother transitions and shallower TES depletion cycles. During early morning and overnight hours, grid power supplements demand, reducing the pressure on TES to provide extended discharge, while in the isolated configuration, load must be entirely met by PV and TES. As a result, TES is cycled more deeply, and brief periods of unmet load occur primarily in the early morning hours when TES is depleted and solar input has not yet resumed.

The bottom sections highlights the implications of these differences for ice production and PV utilization. In the grid-tied system, PV energy remaining after initial ice-making and load satisfaction is completely directed to TES charging, as the grid is available to produce the ice needed to accommodate excess heat in the TES. In contrast, the isolated system relies solely on PV for ice-production, limiting ice production to periods when surplus solar is available and reducing effectiveness of the excess PV stored in TES. This constraint leads to oversized PV systems compared to grid-tied systems for the same LMP, consequently increasing annual curtailment of PV energy in the isolated case, as there are fewer flexible loads available to absorb midday excess.

|  |
| --- |
| Fig. 8 Seasonal variation in hourly energy delivery to the load for a grid-tied system in Page, AZ at 85% load met |

A screenshot of a graph

AI-generated content may be incorrect.Together, this result highlights that grid availability enhances the system’s ability to smooth variability, maintain ice charging ability, more effectively utilize excess PV generation, and reduce the need for overdesign of generation and storage.

Figure 8 illustrates seasonal variations in energy delivery for a grid-tied system in Page, AZ at the 85% load-met case. Four representative days - April 15 (spring), July 15 (summer), October 15 (fall), and January 15 (winter) - demonstrate how contributions from PV, TES, and the grid shift throughout the year. In spring and summer, PV generation is high and well-aligned with demand, allowing the system to meet most of the load directly from PV. TES is discharged during early morning and evening hours, while grid reliance remains minimal. In fall, reduced solar availability leads to moderate grid use, particularly in early morning hours when TES has not fully recharged.

Winter represents the most constrained scenario. TES is typically fully depleted by early morning, and lower solar resource availability means insufficient energy is available to recharge it fully. Grid power plays a much more substantial role, meeting 40.5% of the daily load on average during January, compared to just 15% across the full year. Although PV generation eventually ramps up during midday and satisfies much of the load, grid reliance resurges in the evening as TES is again depleted.

**Capital Cost Breakdown and Sensitivity Analysis**

Figure 10 presents the CAPEX breakdown by component for the grid-tied systems achieving 85% load met across the locations analyzed in this study. Across all sites, due to their high capacities in this high LMP scenario, PV capital expenditures dominate total system cost, contributing approximately 60–70% of total CAPEX. TES and the power block represent smaller fractions, while CSP accounts for a modest but location-dependent share. Notably, the highest overall CAPEX values are observed in humid or lower-irradiance climates such as West Virginia and Clearwater, Florida, due to the increased PV and TES capacities required to achieve similar performance.

A graph of different colored bars

AI-generated content may be incorrect.

Fig. 10. Component-wise CAPEX breakdown for the 85% load-met, grid-tied system across twelve U.S. locations.

Figure 11 shows a sensitivity analysis for the Page, AZ system, demonstrating the LCOE response to ±20% cost variation in each component. The results confirm that LCOE is most sensitive to PV capital costs, with a swing of ±0.01–0.008 $/kWh. Power block costs also have a notable impact, while CSP and TES cost variations produce smaller effects. This aligns with earlier findings that systems are generally PV-dominant at optimal sizing, and that CSP is deployed more conservatively due to its higher cost per unit capacity. While hybridization with CSP enables firm dispatchability and higher load coverage, PV remains the most influential cost lever. Future cost declines in TES and power block technologies could improve system economics further, particularly for isolated configurations requiring more flexible and independent operation.

A graph with different colored squares

AI-generated content may be incorrect.

Fig. 11. Tornado plot showing LCOE sensitivity to ±20% variation in subsystem capital costs for the Page, AZ grid-tied case.

Conclusion

This study evaluates the technoeconomic performance of a hybrid solar energy system integrating PV, CSP, TES and ice-based cooling with a sCO2 Brayton cycle, evaluating this system for both grid-tied and isolated configurations across twelve U.S. locations. Simulations were performed using 2020 meteorological data, with parametric sweeps and sensitivity analyses used to identify optimal system designs at various load met targets.

Grid-tied systems typically achieved lower LCOEs at moderate reliability levels due to their ability to supplement solar generation with inexpensive grid electricity ($0.03/kWh). The lowest LCOEs for grid-tied systems occurred in DNI-rich locations such as Las Cruces, NM ($0.081/kWh), El Paso, TX ($0.081/kWh), and Otero County, NM ($0.080/kWh) at >50% load met. For isolated systems, the lowest LCOEs were slightly higher, at $0.109–$0.114/kWh in those same locations. At 85% load met, LCOEs increased in both configurations, reaching $0.141–$0.146/kWh for grid-tied systems and $0.140–$0.149/kWh for isolated systems in top-performing locations. In Page, AZ, for example, the 85% load met case yielded an LCOE of $0.146/kWh (grid-tied) and $0.149/kWh (isolated).

Performance declined in locations with lower solar resource or higher ambient temperatures. In New Martinsville, WV, grid-tied and isolated LCOEs reached $0.181/kWh and $0.187/kWh, respectively, due to higher system oversizing requirements and reduced efficiency of the thermal-to-electric conversion cycle.

The inclusion of TES significantly reduced PV curtailment, particularly at capacities up to 2 × 105 kWhₜₕ, beyond which further benefit diminished. Isolated systems exhibited higher curtailment (4–5%) than grid-tied systems (2–3%) due to the lack of supplemental energy sources and the need for larger PV arrays. Seasonal simulation in Page, AZ showed that while grid reliance was minimal in summer and spring, winter grid dependence peaked at 40.5% of the daily load, compared to an annual average of 15%.

Sensitivity analysis revealed that PV capital cost was the dominant cost driver, shifting LCOE by ±0.01–0.008 $/kWh with ±20% variation, while TES and CSP costs had smaller effects.

These results demonstrate that hybrid PV–CSP–TES systems can achieve competitive LCOEs between $0.14–$0.16/kWh at 85% load met in favorable U.S. locations, with isolated systems achieving near-equivalence at high LMPs. In particular, grid-tied configurations benefit from the ability to allocate excess PV generation to charging TES, since ice production energy can be drawn from the grid when necessary. This enables more efficient utilization of PV energy and allows grid-tied systems to achieve similar reliability with smaller PV arrays compared to isolated systems, which must reserve a portion of PV output for ice production. The optimal configuration depends strongly on reliability requirements, local solar resource, and capital cost assumptions.

References

[1] Denholm, Paul, Wesley Cole, and Nate Blair. 2023. Moving Beyond 4-Hour Li-Ion Batteries: Challenges and Opportunities for Long(er)-Duration Energy Storage. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85878.

[2] Ju, Xing, et al. "A review on the development of photovoltaic/concentrated solar power (PV-CSP) hybrid systems." Solar Energy Materials and Solar Cells 161 (2017): 305-327.

[3] Aguilar-Jiménez, J. A., et al. "Techno-economic analysis of a hybrid PV-CSP system with thermal energy storage applied to isolated microgrids." Solar Energy 174 (2018): 55-65.

[4] Zhai, Rongrong, et al. "The daily and annual technical-economic analysis of the thermal storage PV-CSP system in two dispatch strategies." Energy Conversion and Management 154 (2017): 56-67.

[5] Petrollese, Mario, and Daniele Cocco. "Optimal design of a hybrid CSP-PV plant for achieving the full dispatchability of solar energy power plants." Solar Energy 137 (2016): 477-489.

[6] Burgaleta, Juan Ignacio, Santiago Arias, and Diego Ramirez. "Gemasolar, the first tower thermosolar commercial plant with molten salt storage." SolarPACES, Granada, Spain (2011): 20-23.

[7] Aqachmar, Zineb, et al. "Parabolic trough solar thermal power plant Noor I in Morocco." Energy 178 (2019): 572-584.

[8] Aqachmar, Zineb, et al. "Parabolic trough solar thermal power plant Noor I in Morocco." Energy 178 (2019): 572-584.

[9] Khan, Muhammad Imran, et al. "The economics of concentrating solar power (CSP): Assessing cost competitiveness and deployment potential." Renewable and Sustainable Energy Reviews 200 (2024): 114551.

[10] Boretti, Alberto, and Stefania Castelletto. "Cost and performance of CSP and PV plants of capacity above 100 MW operating in the United States of America." Renewable Energy Focus 39 (2021): 90-98.

[11] Osorio, Julian D., et al. Failure Analysis for Molten Salt Thermal Energy Storage Tanks for In-Service CSP Plants. No. NREL/TP-5700-89036. National Renewable Energy Laboratory (NREL), Golden, CO (United States), 2024.

[12] Ahmed Liqreina, Louy Qoaider,

Dry cooling of concentrating solar power (CSP) plants, an economic competitive option for the desert regions of the MENA region, Solar Energy, Volume 103, 2014, Pages 417-424, ISSN 0038-092X

[13] Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby. 2018. "[The National Solar Radiation Data Base (NSRDB)](https://doi.org/10.1016/j.rser.2018.03.003)." Renewable and Sustainable Energy Reviews  89 (June): 51-60.