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Techno-Economic Analysis of a Thermally Integrated Solid Oxide Fuel Cell and Compressed Air Energy Storage Hybrid System

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Abstract: Natural-gas-fueled solid oxide fuel cell (SOFC) systems have the potential for high-efficiency conversion of carbon to power due to the underlying electrochemical conversion process while readily facilitating carbon capture through the separation of the fuel and oxidant sources. Compressed air energy storage (CAES) technology can potentially store significant quantities of energy for later use with a high round-trip efficiency and lower cost when compared with state-of-the-art battery technology. The base load generation capability of SOFC can be coupled with CAES technology to provide a potentially flexible, low-carbon solution to meet the fluctuating electricity demands imposed by the increasing share of intermittent variable renewable energy (VRE) production. SOFC and CAES can be hybridized through thermal integration to maximize power output during periods of high electrical demand and then store power when either demand is low or renewable generation reduces power prices. The techno-economics of a low-carbon hybrid SOFC and CAES system was developed and investigated in the present study. The proposed hybrid system was found to be cost-competitive with other power-generating base-load facilities when power availability was considered. The hybrid system shows increased resilience to changes in a high VRE grid market scenario.

Keywords: solid oxide fuel cells; compressed air energy storage; techno-economic analysis; hybrid energy system; carbon capture; power system cycling

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1. Introduction

Solid oxide fuel cells (SOFCs) are a promising electrochemical technology that can convert chemical energy to electricity at a higher efficiency than conventional power plants. This, combined with the relative ease at which their carbon dioxide (CO_2) emissions can be separated (when fueled with carbon-based fuels), makes them an attractive component of the transition to a decarbonized power sector. Further, flexible generation systems are required to address reliability challenges arising from the intermittent nature of a growing fleet of variable renewable energy (VRE) technologies. Traditionally, SOFC systems have been designed to operate as base load generators precluding degradation from thermal cycling. Accordingly, concepts that feature SOFCs as part of an integrated energy system have been proposed, which can permit steady-state operation of the SOFC system while offering the flexibility required by the grid. The simplest integrated energy systems involve direct coupling between a SOFC and an energy storage unit. Energy storage options are being explored globally to provide a mechanism to compensate for the intermittency of VRE power generation. Pumped hydro storage, compressed air energy storage (CAES), flywheels, advanced batteries, thermal storage, hydrogen (H_2) storage, and other technologies are being evaluated in terms of storage capacity, duration, and cost [1–4].

Other configurations include systems where the SOFC operates in tandem with other electricity-generating units (EGUs), such as gas turbine, fossil-based, and nuclear power plants, to coproduce power and value-added products, including H_2 and synthetic fuels [5–7]. The premise of these systems is that SOFCs (and other EGU technologies) can generate power, produce commodities, or do a combination of both, offering a high degree of flexibility depending on the electricity demand.

Accordingly, the National Energy Technology Laboratory (NETL) has been investigating the potential of coupling SOFCs with other EGUs and/or energy storage technologies. Initially, an internal review of potential hybridized concepts was developed using a qualitative method of comparison, which identified a SOFC system integrated with CAES as one of the promising concepts [8]. This is in alignment with studies that indicate that among the storage options being considered (apart from pumped hydro), the CAES technology has the highest level of maturity and the potential to be the most cost-effective option for large-scale, long-duration energy storage [1–4,9].

The SOFC and CAES (SOFC+CAES) hybrid concept can ramp up power production to meet periods of high grid demand and ramp down through multiple strategies that avoid the adverse effects of cycling the system. The SOFC+CAES system accomplishes this by diverting SOFC power during low-demand periods to compress air for storage in a cavern and then expanding the compressed air across a turbine to supplement SOFC power during high-demand periods. In addition to the system's flexibility in meeting electricity demand, the applicability of the SOFC+CAES system to utility-scale fossil-fueled systems with large-scale energy storage is of particular interest to the mission and vision of the U.S. Department of Energy (DOE) and NETL.

While the general coupling of CAES within the context of VRE and conventional technologies such as combined cycle gas turbine plants has been explored [9,10], there have been fewer studies of CAES integration with SOFC plants. Nease and Adams focused on baseload capacity SOFC systems >700 MW integrated with CAES capabilities for load-following and peaking power. The team optimized the charging and discharging schedule of a fixed-design SOFC+CAES system to maximize the levelized cost of electricity (LCOE) [11,12]. These studies investigate pairing a CAES system with a pressurized SOFC system operating at ≈10 bar using a high-temperature (≈950 °C) electrolyte-supported SOFC. More recently, Roushenas et al. [13,14] explored the exergetics and economics of a tri-generation integrated system based on a combination of SOFC+CAES and a turbocharger. A similar hybrid configuration utilizing a molten carbonate fuel cell instead of a turbocharger was analyzed by Jienkulsawad et al. [15]. The system configuration features an external natural gas reformer coupled with water–gas shift reactors to generate a feed stream consisting of primarily H_2 and CO_2.

This work details the results of the techno-economic analysis (TEA) of a SOFC system integrated with a CAES system. The characteristics of the CAES system are matched to the SOFC system through careful thermal integration that avoids the requirement of external thermal energy during the discharge of air from the cavern. A bottoming steam cycle utilizes the excess heat available during charging. Charging and discharging rates and energy storage amounts are important variables to consider when sizing an energy storage system. For time-scale comparison, the base charge/discharge ratio is 1:1 (12 h of charging followed by 12 h of discharge per day). Five sensitivity studies were completed to discern the effects of cavern pressure, cavern type, turbine inlet temperature, charge/discharge ratio, and power output. LCOE was evaluated and used as the metric for comparison for the hybrid system and other standalone systems.

2. Materials and Methods

The hybrid SOFC+CAES concept investigated in this work consists of an atmospheric pressure natural-gas-fueled SOFC plant combined with a solution-mined salt cavern CAES system. During periods of low grid electricity demand or low electricity price, power is used to store air underground in the cavern at pressure. During periods of higher grid electricity demand or high electricity prices, the compressed air is released and passed through an air turbine to generate power to supplement the SOFC. This study changes the notions of low- and high-electricity demand for the charging and discharging of the cavern. The block flow diagrams for the charging and discharging modes are shown in Figures 1 and 2, respectively.

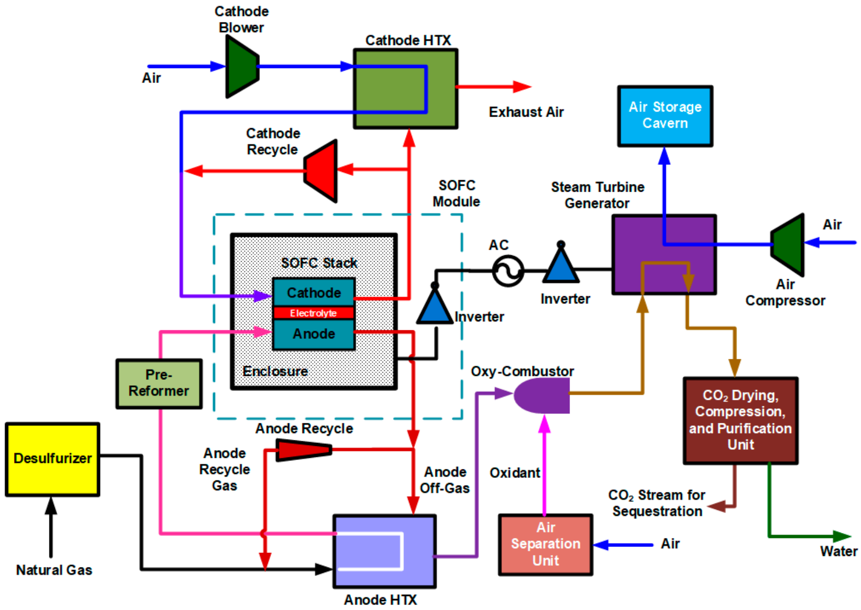

Figure 1. System charging block flow diagram.

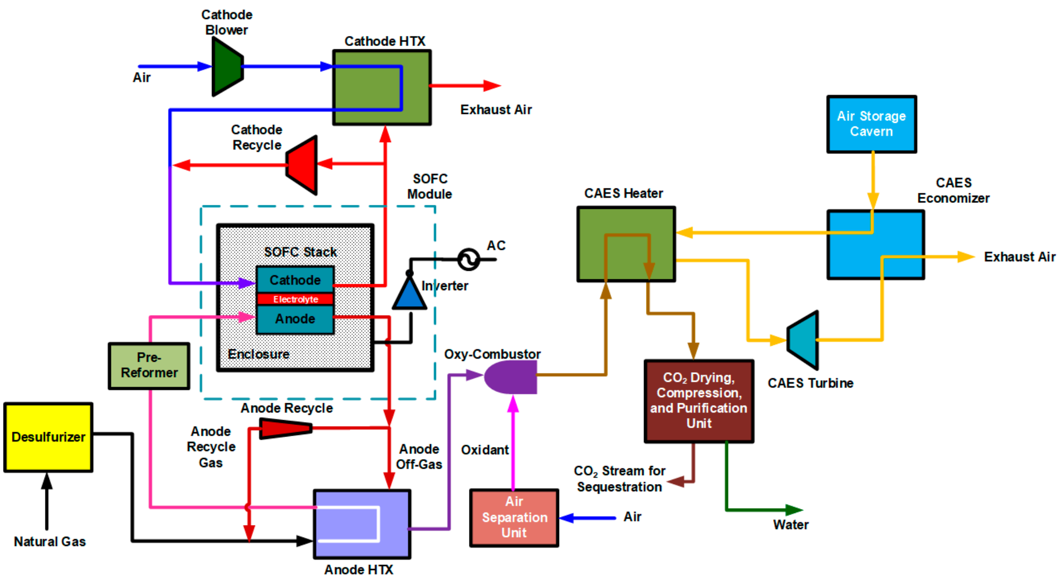

Figure 2. System discharging block flow diagram.

2.1. SOFC System

The SOFC system, as represented by the block flow diagrams in Figures 1 and 2, is based on the ANGFC3B case from the natural gas fuel cell (NGFC) techno-economic pathway study [16]. This system, based on an anode-supported planar cell stack operating at atmospheric pressure, demonstrates high efficiency and low LCOE. SOFC technology that can support the complete internal reformation of natural gas within the stack is assumed. The SOFC operates at 85% fuel utilization during both the charge and discharge modes of operation. During discharge, the SOFC produces a net power of 250 MWe, corresponding to a SOFC design current density of 400 mA/cm^2. The current density is tuned to match the electricity demand from the grid and/or the CAES system during charging mode. Process air, with temperature and flow rates modulated to thermally manage the SOFC, acts as both the reaction oxidant and the stack coolant. The SOFC systems feature separated fuel and gas streams that, along with utilizing oxygen from an air separation unit (ASU) for oxy-combustion of the unused fuel, enable a low cost of carbon capture. Anode off-gas is recirculated to provide steam for natural gas reformation and to avoid carbon deposition by maintaining the desired oxygen-to-carbon ratio. The cathode exhaust is recirculated to avert cost-prohibitive heat exchanger sizes. The thermal energy in both the cathode and the oxy-combustor exhaust is recovered in a Rankine bottoming cycle. The oxy-combustor exhaust, consisting mostly of CO_2 and water, is dried, compressed, and purified in an autorefrigerated CO_2 purification unit (CPU) capable of 98% CO_2 capture to support pipeline transport to a CO_2 storage location. Additional details on the SOFC system can be found in NETL's published NGFC TEA studies [16].

2.2. CAES System

A large underground salt cavern, solution-mined to create a volume large enough to store compressed air, forms a major component of the CAES system. During charging operation, an adiabatic single-stage compressor is used to compress ambient air to cavern pressures that generally vary between 40 and 70 bar. Following compression, the air is cooled to remove the heat of compression, reducing the temperature to the cavern temperature. For discharge operation, a throttling valve at the cavern exhaust is used to regulate the compressed air stream to 40 bar, which is heated to a specified turbine inlet temperature prior to expansion in the air turbine.

2.3. System Modeling

System models were developed under the Aspen Plus® (Aspen) V8.4 platform to simulate the hybrid system. SOFC system performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment as described in the NGFC TEA pathway study [16]. The CAES system was designed primarily based on systems described by Nease, Monteiro, and Adams [12]. The plants simulated were assumed to be located at a generic Midwestern United States site operating at International Organization for Standardization ambient conditions [17].

2.3.1. SOFC Plant

The SOFC voltage and thermal characteristics were computed using a reduced-order model (ROM) developed through a collaboration between NETL and Pacific Northwest National Laboratory (PNNL). The PNNL ROM model is based on a response surface methodology [18] applied to detailed SOFC stack model results to create a computationally efficient ROM for the stack that retains desirable information about its internal state. For the SOFC, the input variables could constitute operational parameters such as fuel/oxidant compositions, temperatures, flow rates, and utilization. Response variables could include electrical performance characteristics such as stack voltage, power output, and efficiency. Peak cell/stack temperature, cell temperature gradient, or maximum local current density are among other response variables that may be of interest due to their influence on cell/stack structural stability and performance degradation. More details on the ROM and its application to the system models can be found in [19,20]. Salient plant assumptions that are used to predict SOFC performance and thermal characteristics are listed in Table 1.

Table 1. SOFC plant assumptions.

SOFC Pressure	Atmospheric
SOFC fuel utilization (%)	85
Current density (mA/cm^2)	400
Natural gas reformation	100% internal
Cathode recycle rate (%)	50
Oxygen to carbon ratio in anode	2.1
SOFC ΔT (°C)	100
SOFC max T (°C)	750

2.3.2. CAES Plant

The CAES system heat exchangers, compressors, and turbine components are modeled in Aspen. The turbine exhaust is recuperated to preheat the incoming air via a heat exchanger. The cavern is indirectly represented assuming a certain volume and pressure. For this study, the primary cycle time is selected to be a 12 h charge and 12 h discharge cycle within a day. During cycling, the cavern is charged up to the maximum cavern pressure, and then later discharged to the minimum pressure. Salient assumptions for the CAES system in the reference case are shown in Table 2.

Table 2. CAES assumptions.

Maximum cavern pressure (bar)	70
Minimum cavern pressure (bar)	40
Isothermal cavern temperature (°C)	50
Turbine inlet temperature (°C)	900
Inlet air pressure (bar)	1
Charge/discharge cycle (hour)	12–12
Maximum cavern pressure (bar)	70
Minimum cavern pressure (bar)	40

2.3.3. Dynamics and Heat Integration

A comprehensive model of the hybrid system would require a dynamic representation of each component. The present study uses a quasi-steady approach utilizing steady-state SOFC and CAES plant models to capture salient aspects of interactions between the systems. The SOFC plants and the CAES systems are modeled on separate flowsheets and are coupled using a spreadsheet for the charging and discharging cycles.

The hybrid system is designed so that the SOFC system operates continuously throughout the discharge and charge modes to avoid deleterious thermal cycling. As shown from the high-level block flow diagram in Figure 3, a thermal manager block, which includes equipment such as heat exchangers and thermal storage units, is introduced to enable efficient heat integration between the SOFC and CAES systems, including the steam cycle. The thermal manager ensures that the integrated process is self-sustaining with no external heat input requirement while maximizing heat utilization (apart from the normal heat rejection from a Rankine cycle) during both the discharge and charge modes. Initial considerations showed that a power ratio (P_{SC}) of 3.1 between the SOFC plant and the CAES plant turbine would be optimal from a thermal integration perspective. The P_{SC} value is dependent on the SOFC operating point and cell/stack technology. Generally, a more efficient SOFC will generate less heat (at the same power rating) and will support a smaller turbine power rating. On the other hand, a less efficient SOFC will support a higher power air turbine albeit at a lower overall process efficiency. Further, apart from adding significant capital costs, a thermal storage unit was found to require undesirable external heating of the air during discharge to support preferred turbine inlet temperatures. (Thermal storage units will have to operate above 900 °C to achieve the desired turbine inlet temperature. Current thermal storage technologies such as molten salt are limited to less than 650 °C. Further, these storage technologies have a charge/discharge temperature range that would not be consistent with the total spectrum of heat available during both charge and discharge.) Accordingly, only heat exchangers were considered as the thermal management equipment of choice in this study.

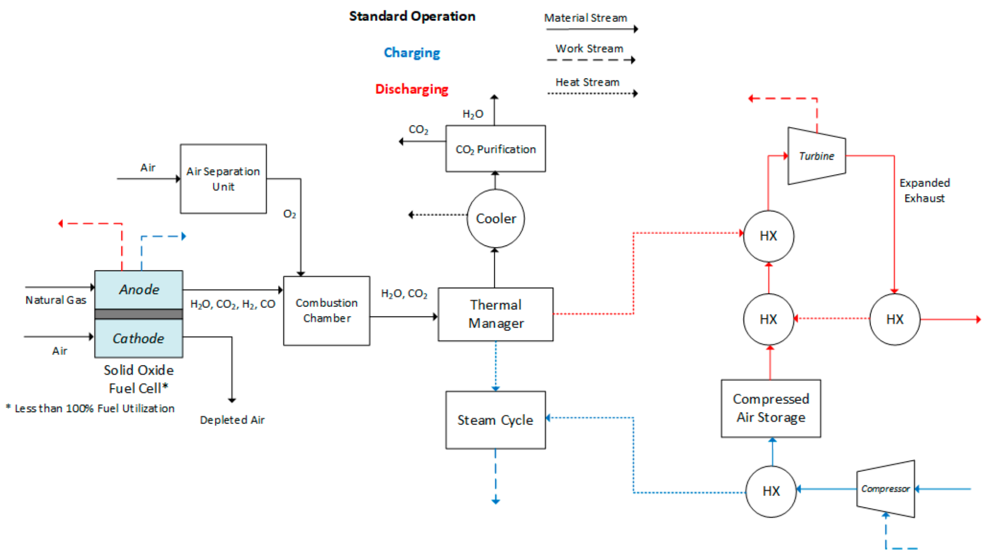

Figure 3. SOFC+CAES hybrid system process.

During the charging mode, the heat generated during air compression is sent to the heat recovery steam generator (HRSG) that supplements the SOFC exhaust heat to generate steam for the steam bottoming cycle; however, in the discharge mode, all the heat in the SOFC exhaust is required to heat the CAES air to the turbine inlet temperature, and consequently, the steam cycle remains inactive.

With a P_{SC} value of 3.1, the SOFC system power may have to ramp down (Note that the SOFC stack is only power cycled by decreasing the current density, which in practice can be achieved at high ramp rates depending on the fuel and air flow controllers. Through appropriate thermal management, the stack can continue to operate at its desired temperature, avoiding any undesirable thermal cycling.) during charging depending on the grid's electricity demand. The SOFC reduces power output to a point where the electricity produced by the SOFC stack combined with the steam turbine generator provides sufficient power for compressing and storing the air in the cavern. This power could be as low as net-zero electricity produced, meaning the system only produces enough power to cover the requirements of the air compressor and other auxiliary loads.

2.3.4. Costing Methodology

Capital and production cost estimates follow the economic basis applied in the NETL Fossil Energy Baseline (FEB) report [17], which provides factored estimates developed for each plant section for conventional fossil fuel plants. This report scales those costs for comparable plant sections that appear in the NGFC plants according to the NETL Quality Guidelines for Energy System Studies (QGESS) on capital cost scaling [21]. Costs for systems not included in the FEB were taken from estimates used in the NGFC techno-economic pathway study [16]. This study presents capital costs at the total plant cost (TPC), total overnight cost, and total as-spent cost levels [17,22]. The CO_2 transport and storage cost is estimated at USD 10/tonne of CO_2 in accordance with the QGESS specifications [23].

2.3.5. Case Descriptions

For this study, a base case and five sensitivity studies are assessed to gain insight into various performance and cost possibilities of the hybrid system. A 250 MWe SOFC is chosen for all systems, as this scale of generation is more feasible in the near term versus much larger scales explored in previous studies. (Note that the methodology can easily be applied to systems at other scales suitable to the market.) From this base case, heat integration of the system will define the scale of the CAES turbine such that only heat supplied from the SOFC system will be needed to heat the released cavern air to the turbine inlet temperature. For Case 0, being designated as the base case, the heat integration results in an 80 MWe CAES power-generating turbine.

Case 1 modifies the assumption of the local geology supporting a salt cavern deep enough to reach 70 bar by using a shallower "bedded" cavern. This cavern is modeled by changing the cavern minimum and maximum pressures to 20 and 35 bar, respectively. This leads to more cavern volume required to store the air. There is also a cost increase due to the increased volume. Additionally, when the throttling pressure is reduced from 40 to 20 bar, the heat integration changes slightly, altering the CAES power-generating turbine to an output of 75 Mwe.

Case 2 is purely an economic sensitivity that assumes that there is an existing cavern (natural or depleted natural gas reservoir) that is of proper volume to be used for CAES. There are no performance variations from Case 0, but the cavern cost in the economic analysis is reduced, as the site would not need to be solution-mined.

Case 3 sets the turbine inlet temperature to 600 °C, which changes the thermal integration of the system. By lowering the inlet temperature, a higher volume of air is required to absorb the heat produced by the SOFC system. The lower inlet temperature also results in reduced turbine performance, which reduces power output to under 80 MWe. Finally, the turbine outlet temperature is reduced to a point where an economizer heat exchanger is no longer needed.

Case 4 changes the system dynamics by investigating the effects of an 8 h charge time with a 16 h discharge time. A shortened charge time means a larger air compressor to store the air needed during discharge. The charging system will ramp differently to accommodate both the increased auxiliary power requirements of the air compressor and the heat produced. The discharge performance is not affected.

Case 5 does not allow the SOFC system to ramp down during charging, which results in a net positive power output of the entire system. This leads to a change in the charging system having additional heat available for a larger HRSG in addition to the power output from the SOFC. Discharge performance is unchanged. All key assumptions are given in Table 3.

Table 3. Case matrix.

Parameter	Case 0	Case 1	Case 2	Case 3	Case 4	Case 5
SOFC scale (MW)	250	250	250	250	250	250
CAES scale (MW)	80	75	80	<80	80	80
Cavern min pressure (bar)	40	20	40	40	40	40
Cavern max pressure (bar)	70	35	70	70	70	70
Cavern type	New	Shallow	Existing	New	New	New
Turbine inlet temperature (°C)	900	900	900	600	900	900
Charge/discharge cycle (hours)	12–12	12–12	12–12	12–12	8–16	12–12 + full SOFC

3. Results

3.1. Case Subsystems

For each case, four separate quasi-steady-state models are simulated to generate the performance results. The combination of models represents both the charge and discharge states along with the storage cavern operating near both maximum and minimum pressure to create a range of auxiliary loads and performance results.

Auxiliary loads represent the power required to run the equipment in the hybrid system. System performance tables show the gross and net plant power along with associated full system inputs, outputs, and other key metrics. Due to the setup of the dynamic charge and discharge cycle, maximum gross and net power are achieved during discharge, while minimal and near-zero gross and net power (respectively) are shown during charging. It should be noted that net plant efficiency is based on thermal inputs to system power outputs; however, while natural gas supplies a thermal input, the potential energy being released from stored compressed air is not accounted for during discharge.

3.2. Case Comparison Study

Due to the dynamic cycle, additional efficiency metrics are explored to gain further insights into the performance of the hybrid system. Most notably for a system that includes energy storage, the round-trip efficiency measures how well the stored energy is recovered. As such, the values of the system across the entire cycle are used to estimate the efficiency. The definitions used for round-trip and apparent charging efficiencies are shown in Equations (1) and (2).

$$Round - Trip\ Efficiency = \frac{Full\ Cycle\ Net\ Plant\ Power}{Full\ Cycle\ Thermal\ Input\ (HHV)} \tag{1}$$

$$Apparent\ Charging\ Efficiency = \frac{Round - Trip\ Efficiency}{Discharge\ Efficiency} \tag{2}$$

The completed subsystem models are combined to create overall plant performance metrics for each case. Key metrics include net auxiliary loads during the charge and discharge portions of the cycle; discharge net plant power that corresponds to maximum or peak power output; and full-cycle metrics such as kilowatt (electric) hours (kWeh), thermal input, and efficiencies along with carbon capture rates, air flowrates, fuel flowrates, condenser duties, and water usage.

Net auxiliary load requirements during discharge remain consistent across all cases with minor variations due to small changes in thermal integration. The larger variance in auxiliary load requirements occurs during charging, where the air compressor power needs to dominate. Case 1, which demonstrates a shallow cavern with lower pressure, has lower auxiliary loads, while Cases 3 and 4 both have higher power requirements due to the necessity of storing larger amounts of compressed air. Case 5 has auxiliary requirements similar to the base case, only slightly elevated due to other power needs driven by the increased SOFC output.

Discharge net power fluctuates slightly between cases based on auxiliary loads and CAES turbine power output but remains close to 310 MW; however, looking at a full cycle of charging and discharging, Case 4 outputs roughly 30% more electricity due to the additional 4 h of discharge, while Case 5 outputs more than 60% additional power by not ramping down the fuel cell power during charging.

Net plant efficiency compares the thermal input of the system with the net plant power output over an entire charge/discharge cycle. This definition places the plant efficiency similar to the round-trip efficiency of the hybrid system. For each case, the net cycle efficiency is around 61%, with Case 1 having a slightly higher efficiency due to the lower compression needs, Case 3 having a lower efficiency due to lower thermal integration stemming from a lower turbine temperature, and Case 5 showcasing a higher efficiency by having a higher power output from the more efficient SOFC system.

Compressed air flowrate is a representative metric to relate to the size of the cavern required for the system. While running at a lower cavern pressure, less than a 10% greater mass of air is required for the system, but this is at a lower pressure, i.e., a much larger volume. For Cases 3 and 4, having a lower turbine temperature means that the system requires even more air than a system with a longer-duration discharge, showing the importance of the thermal integration and operation of the CAES turbine. These metrics are outlined further in Table 4.

Table 4. Primary case performance comparisons.

Plant Performance	Case 0 *	Case 1	Case 3	Case 4	Case 5
Discharge net auxiliary load (kWe)	18,000	18,000	18,000	18,000	18,000
Charge net auxiliary load (kWe)	111,000	90,000	151,000	222,500	125,000
Discharge net plant power (kWe)	311,500	307,000	311,000	311,500	311,500
Full-cycle net plant power (kWeh)	3,740,000	3,690,000	3,740,000	5,000,000	6,180,000
Full-cycle thermal input (kWh)	6,100,000	5,870,000	6,500,000	8,120,000	9,850,000
Net plant efficiency (higher heating value) (%)	61.3	62.9	57.3	61.4	62.7
Round-trip efficiency (%)	61.1	62.8	57.0	61.0	70.7
Apparent charging efficiency (%)	80.4	83.8	75.1	80.4	93.1
Compressed air flowrate (kg/day)	9,900,000	10,680,000	13,480,000	13,200,000	9,900,000
Natural gas feed flowrate (kg/day)	420,000	400,000	450,000	560,000	680,000

* Case 2 exhibits the same performance results as Case 0 and is not shown here.

3.3. Economic Results

SOFC system cost estimates are developed using values from the NGFC techno-economic pathway report [20]. All SOFC cost accounts are scaled based on the performance results. The CAES system cost estimates are based on the 2020 Grid Energy Storage Technology Cost and Performance Assessment technical report conducted by DOE's PNNL [24]. This report evaluates multiple energy storage options, including CAES. The report includes cost data from the two real-world CAES facilities from the McIntosh Plant in Alabama, United States, and Huntorf, Germany. The evaluation also incorporates cost estimates from the Electric Power Research Institute, Black & Veatch, Siemens, and Bethel Energy Center. Fixed capital installed costs include facility equipment such as the turbine, compressor, balance of plant, and engineering, procurement, and construction management costs. Cavern capital costs reflect the costs to drill and solution-mine a suitably sized salt cavern. In this study, there are five key costs associated with the CAES system: the air compressor, salt cavern, air turbine, economizer heat exchanger, and turbine inlet heat exchanger. Air compressor and salt cavern costs are based on values from the 2020 report, where the remaining pieces of equipment are scaled and costed based on similar equipment from the NGFC techno-economic pathway study [16,24].

3.3.1. Total Plant Costs

To generate total plant costs, each system is divided into its four main subsystems. These subsystems are individually evaluated based on performance, which leads to sizes and scaling for the cost components. After the initial cost estimation, the total hybrid system costs are estimated as a combination of the maximum cost for each subsystem and the maximum cost taken from each subaccount. This leads to a more accurate representation of the actual equipment needed by the hybrid system than simply taking the maximum across all subsystems.

Across all cases, the same-sized SOFC power island (250 MWe) is considered. During discharge, the full output is realized and results in the full system cost. During charging, the SOFC is ramped down so each subsystem is sized and costed accordingly. Since SOFC systems are costed in modules, some rounding occurs to where some cases have the same SOFC system costs during both charging subsystems while others are different. This primarily illustrates the minimum SOFC system size required, as the discharge case always produces the largest system needed for the overall case.

CAES system costs are dominated by the air compressor and air turbine. Since the performance of the turbine varies slightly across the cases, turbine costs do not vary much; however, the auxiliary load of the air compressor can vary widely from case to case depending on the maximum pressure of the cavern and the volume of air required to be stored.

The ASU costs are consistent across all cases, as they are tied to the SOFC system requiring a certain amount of oxygen to combust unspent fuel leaving the fuel cell. Similarly, CO_2 compression costs are the same between cases. The remaining plant costs vary between cases based on auxiliary power requirements, water requirements, or other miscellaneous balance-of-plant items.

With all prior cost accounts combined for each overall system in each case, the TPC is calculated. For the base case, a TPC of just over USD 533 million is estimated. From this base cost, Case 1 shows a slightly lower TPC at around USD 502 million, and Case 2 shows only a small decrease from the base case with the established cavern only having minor cost savings. Lowering the turbine inlet temperature in Case 3 results in a larger TPC of just over USD 568 million. The longer discharge time, which requires a larger air compressor to store enough volume of air for Case 4 (the 8–16 h cycle), increases TPC to over USD 664 million, primarily driven by the compressor cost and steam cycle costs seen during charging. Case 5 has a TPC of just under USD 570 million, with increases over the base case driven by increased steam cycle costs of the HRSG utilizing extra heat during charging due to the SOFC system not ramping down. The remaining costs and TPC for each case are shown in Table 5.

Table 5. Total plant cost (TPC) breakdown.

Cost Component (USD 1000)	Case 0	Case 1	Case 2	Case 3	Case 4	Case 5
Total SOFC module with 10% extra installed area	93,000	93,000	93,000	93,000	93,000	93,000
Total SOFC balance of plant	21,500	21,500	21,500	21,500	21,500	21,500
Total SOFC power island	114,500	114,500	114,500	114,500	114,500	114,500
Total CAES system	66,000	68,600	64,400	67,100	93,900	66,000
Air separation unit	40,500	40,500	40,500	40,500	40,500	40,500
Total steam cycle	88,300	79,000	88,300	103,800	130,200	114,600
Total CO_2 compression and purification	45,200	45,200	45,200	45,200	45,200	45,200
Cooling water system	16,600	14,700	16,600	19,700	24,600	24,400
Accessory electric plant	98,300	85,500	98,300	119,900	154,800	106,400
Instrumentation and control	25,500	24,600	25,500	26,800	28,400	26,000
Improvements to site	20,500	20,500	20,500	20,500	20,500	20,500
Building and structures	18,200	8700	9300	10,100	11,500	10,600
TPC (USD 1000)	**533,600**	**501,800**	**523,100**	**568,100**	**664,100**	**568,700**

3.3.2. Levelized Cost of Electricity

The LCOE is the most relevant metric of cost comparison for this hybrid system as opposed to the levelized cost of storage, the rationale being that the system is primarily a power-producing facility with an energy storage component as opposed to being primarily a storage facility. An 85% availability factor is assumed for all systems.

For the sake of comparing the hybrid system presented in this study against other power-producing facilities to gain a better understanding of the hybridized energy storage component, a normalized natural gas fuel cell and natural gas combined cycle (NGCC) are added. The NGFC system is case ANGFC3B from the NGFC techno-economic pathway study, which is also used as the basis for the SOFC system in this work [20]. The NGCC system is based on case B31B.90 from the NETL FEB study [17]. Both systems were normalized for comparison by first adjusting the performance models to bring the net power output to 310 MWe, which is in line with the net power of the hybrid system. Each system was then costed with a reduced capacity factor of 42.5%, which is akin to having an 85% availability factor and outputting net electrical power half of that time as in a 12 h charge and discharge cycle.

The base hybrid system LCOE comes to USD 99.1/MWh. The shallow cavern of Case 1 reduces the LCOE to USD 96.6/MWh by utilizing a reduced-cost air compressor with similar performance to the base case. The reduction in cavern costs seen in Case 2 reduces the LCOE slightly to USD 98.9/MWh. Losing the performance of the CAES turbine with a lower inlet temperature increases the LCOE to USD 106.2/MWh. Despite having the largest TPC across all cases, the additional power output of an 8–16 h cycle as shown in Case 4 reduces the LCOE to USD 92.3/MWh. The reduction to LCOE continues with Case 5, as the more constant SOFC output further reduces the LCOE to USD 73.3/MWh.

As points of comparison, a more standard power plant in the NGCC (646 MWe net plant power at 85% capacity factor) would have an LCOE around USD 68.7/MWh, and the potential NGFC plant could have an LCOE as low as USD 51.7/MWh [18,21]. When these two systems are normalized, the LCOE values increase to USD 119.7/MWh and USD 87.1/MWh, respectively, placing the hybrid systems in this study between them. These LCOE comparisons are shown in Figure 4.

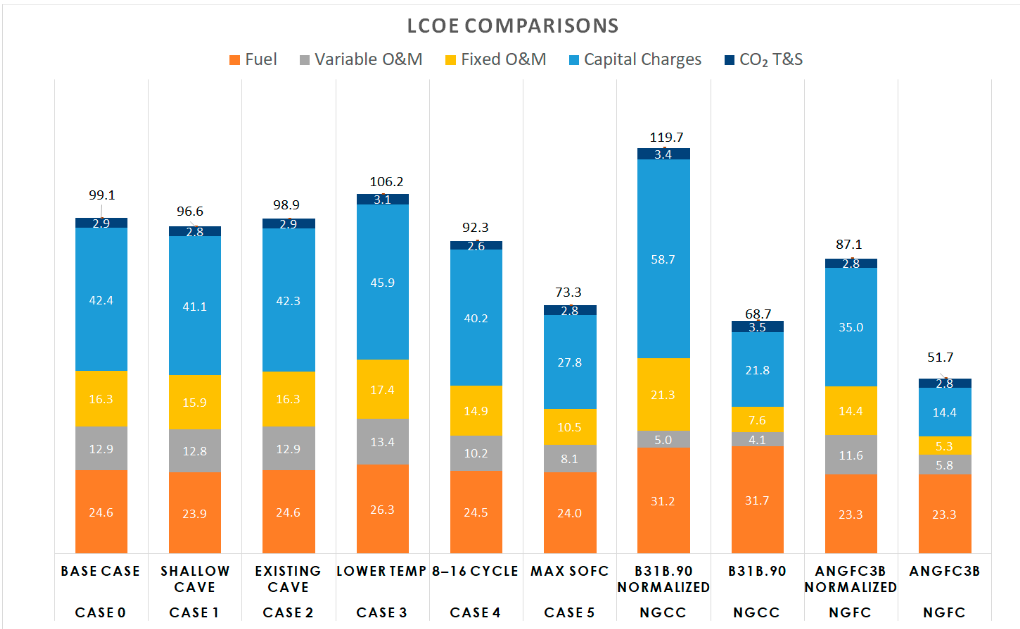

Figure 4. Comparison of LCOE for each case evaluated.

4. Discussion

A critical consideration for the commercialization of SOFC technology is a determination of dynamic operability requirements that achieve flexibility and resilience to be fully compatible with an evolving power grid. By hybridizing SOFC technology into an integrated energy system, some of the challenges associated with widespread deployment can be assuaged. The DOE Office of Fossil Energy and Carbon Management Reversible SOFC Program has appropriately targeted improvements in efficiency and reduction in performance degradation rates and system costs as the critical considerations for accelerated, widespread deployment. While these considerations are necessary and impactful, they do not adequately address the implementation of SOFC technology into an evolving grid scenario with ever-increasing contributions from intermittent VRE resources.

Future fossil-based carbon conversion systems must have the flexibility to integrate and respond to a more dynamic grid environment. Flexibility is essential for ensuring grid reliability and resilience with the goal of lowering CO_2 emissions per unit of energy delivered. Initially envisioned as base load technologies, it is known that solid-state electrochemical conversion technologies are challenged when it comes to their flexibility in responding to grid demand fluctuations due to deleterious effects caused by thermal cycling. From a technology perspective, it is rational to keep the SOFC operating at full capacity, or at the very least in a "hot standby" mode. When grid demand is low, excess electrons are produced that need to be efficiently stored for later use. The challenge of storing excess energy is not unique, with VRE technologies requiring similar solutions. Hybridized SOFC systems offer the potential for greater turndown and fuel flexibility, which make them more compatible with a dynamic power grid than conventional fossil-based power generation systems. Hybridized SOFC systems can potentially increase the efficiency of power generation, resulting in decreased emissions, while the dynamic operability of the SOFC can further help maintain the stability and reliability of the electric grid. Hybrid operations also offer the potential to diversify revenue streams for electricity generators. Location could be a limiting factor for placing a hybrid facility in that the CAES requires an adequately sized geological formation to utilize for the air storage. There may exist a disconnect between available storage and power distribution to where it is needed.

This effort intends to elucidate one strategy of hybridizing SOFC technology with energy storage (CAES) to be a more resilient fossil-based asset. Performance and cost modeling details developed as a part of this work show that a SOFC+CAES hybridized system possesses several traits that relate the individual systems to one another. To make the hybridized system self-reliant, it has been determined that a power ratio of ≈3.1 of the SOFC to CAES-powered turbine (250:80 MWe) thermally integrates the system, eliminating the need for energy input from external sources, such as a natural gas burner. Eliminating the combustion of natural gas outside of the SOFC module avoids additional CO_2 emissions that would be costly to capture. During charging, heat is generated as a result of the SOFC exhaust being oxy-combusted and is available in the compressed air prior to being stored in the cavern. This heat can drive a steam cycle, which can produce ≈40% of the charging auxiliary load power requirements.

The use of a shallow cavern in Case 1 (i.e., reduced-pressure air) results in a slight reduction in LCOE of ≈3%. Lower pressure operation is favorable due to the lower air compressor auxiliary requirements; however, higher volumes of air are required due to the lower pressure, which may be a limiting factor from a geological standpoint. It is also apparent that any system operating closer to the lower bound of pressure would have improved performance. This also results in a slight improvement in round-trip efficiency and apparent charging efficiency, as shown in Table 4. The capital cost reduction associated with implementing an existing cavern (Case 2) has minimal impact on the system economics, with no statistically significant reduction in LCOE realized.

Reducing the turbine inlet temperature (Case 3) increases the LCOE due to the reduced performance of the turbine and excess airflow needed to maintain the thermal integration of the system. The results show that this configuration requires the most compressed air, with an increase over the base case of ≈36%. This would need to be a consideration for designs involving specific turbine equipment.

For simplicity, 12 h of charging and 12 h of discharging is chosen as the base operation scenario and is not based on any optimized grid demand profile. In fact, charging the system over a shorter duration of 8 h and allowing for 16 h of discharge (Case 4) reduces the LCOE by ≈7%. Ideally, an optimization study that aligns system charging and discharging to be most responsive to grid-demand scenarios could improve economics. It also need not be a fully repeating cycle, with an optimum scenario being fully responsive to grid dynamics.

Holding the SOFC power output near maximum capacity throughout operation has a significant impact on the economics as well. As a SOFC can produce electricity with high efficiency, it is rational to conclude that the more electricity that is produced by the SOFC itself, the lower the system LCOE will be. In fact, the "max SOFC case" (Case 5) results in a reduction in LCOE of ≈26%. These results show that managing how the SOFC is used to produce power will have the greatest impact on the bottom-line economics. The round-trip efficiency and apparent charging efficiency are also improved in this case, as shown in Table 4.

The comparison with large-scale base load units (as shown in Figure 4) is interesting. From a base load power production operating at a high capacity factor (85%), the electricity produced by NGCC and NGFC units has a much lower LCOE; however, as these results are normalized toward a similar power production capacity factor demonstrated in the SOFC+CAES system, costs for the capital-intensive NGCC unit (with 90% carbon capture) exceed all the SOFC+CAES systems, while the NGFC system comes closer to economic parity with the SOFC+CAES systems assessed. This demonstrates that moving forward, there may be some economic benefit to considering a hybridized, thermally integrated SOFC system when compared with large-scale base load facilities operating at lower capacity factors. These benefits are more realized in grid scenarios that do not require high availability factors, but instead favor energy storage.

There are several potential avenues to explore for future study relating to flexible operation, costing methodology, and equipment.

- Flexible operation: Base operation may not need to be consecutive (i.e., 12 h charge, then 12 h discharge). Real-world demand, market prices, etc., could be leveraged to develop an optimized process that results in economic system operation with a dynamic grid.
- Economics: Purchasing cheaper electricity from the grid (when available at prices lower than the SOFC can produce) could lower costs during the charging period. This could be realized through an assessment with integrated VRE assets. Moreover, depending on availability and market price for electricity, the economics of swapping to a reversible solid oxide cell to produce H_2 in addition to storing pressurized air could be investigated.
- Equipment: Specialized equipment, air turbines, compressors, etc., may have different base costs or cost scaling that may close or widen the differences in LCOE. The impacts of the benefits of operating the SOFC at pressure could also be investigated, as the pressurization energy needed would be reduced.

5. Conclusions

Changes to the energy generation profile in the United States are occurring at an ever-increasing rate, and with those changes, the next generation of fossil energy systems must be more flexible. The traditional model of serial technology development must change, and the timeline for the development and deployment of new technology options must be compressed to keep pace. This effort has described one potential path for achieving these goals for SOFC systems by employing an integrated approach that builds flexibility of operation into the system.

NETL has been investigating the potential of coupling SOFCs with other EGUs and/or energy storage technologies. Initially, an internal review of potential hybridized concepts was developed using a qualitative method of comparison, which identified a SOFC system integrated with CAES as a promising concept warranting further investigation, as CAES technology has the highest level of maturity and the potential for being the most cost-effective option for large-scale, long-duration energy storage. Several conclusions drawn from the cost and performance analyses conducted on various SOFC+CAES cases are summarized below:

- To meet the heat requirements of the CAES system, a power ratio of ≈3.1 SOFC to CAES eliminates the need for external heat sources.
- During charging, the heat generated can drive a steam cycle.
- Lower pressure operation is favorable due to lower auxiliary compressor requirements; however, higher volumes of air are required.
- Once hybridized, cavern type and cost have minimal impact on LCOE.
- Lower turbine temperatures require the most compressed air (even compared with an 8–16 h cycle), which increases the cost of equipment.
- Longer-duration power output lowers LCOE by having an effectively higher availability factor.
- When normalized for power output and capacity factors, the hybridized system is cost-competitive with NGCC and NGFC plants.

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