16th International Conference on Greenhouse Gas Control Technologies, GHGT-16

23rd-27th October 2022, Lyon, France

Evaluating the economic viability of NGCC-SWITCC: Natural Gas Combined Cycle System With Integrated Thermal storage and Carbon Capture

Braden J. Limb[a], Ethan Markey[a], Roberto Vercellino[a], Joe Huyett[a], Shane Garland[a], Maxwell Pisciotta[b], Peter Psarras[b], Erik Meuleman[c], Nathan Fine[c], Miles Abarr[d], Daniel R. Herber[a], Jason C. Quinn[a], and Todd Bandhauer[a,]*

[a]*Colorado State University, Fort Collins, CO, 80523, USA*
[b]*University of Pennsylvania, Philadelphia, PA, 19104, USA*
[c]*ION Clean Energy, Boulder, CO, 80301, USA*
[d]*Storworks Power, Arvada, CO, 80002, USA*

Abstract

Over the last decade, 121 coal-fired power plants have been decommissioned or converted to natural gas-fired plants due to stricter emissions standards, economic constraints, and social pressures to reduce carbon emissions. As environmental policies continue to be implemented, natural gas power plants are expected to serve as a bridge fuel to replace coal and nuclear loads, as well as to meet peak demands when renewable energy and expensive battery storage is not available. To meet the Paris Agreement climate goals, carbon capture and sequestration (CCS) will be required on every natural gas power plant. However, major drawbacks to utilizing CCS systems include the large parasitic heat load placed on the power plant and a reduction in plant's operating flexibility. To overcome these issues, the team has developed the Natural Gas Combined Cycle System With Integrated Thermal storage and Carbon Capture (NGCC-SWITCC) concept, which incorporates thermal energy storage (TES) with natural gas combined cycle (NGCC) power plants that use CCS. This research evaluates the economic viability of the NGCC-SWITCC system in future electric grids with a high penetration of variable renewable energy systems.

The TES component can be made up of dual hot and cold thermal units and can provide many benefits for the NGCC-SWITCC approach. First, hot thermal storage can be used to supply heat to the CCS unit during times of peak power demand which increases the overall power output to the grid. Second, cold thermal storage can be used to chill the power plant inlet air which increases efficiency and power output. Third, TES units can charge during times of low electricity demand and discharge during peak demand which increases overall power plant profitability. Lastly, the charging and discharging of the thermal storage system allows the power plant to have a more flexible power output range than comparable NGCC+CCS systems. The models developed for this work consist of three interconnected technology, optimization, and techno-economic models. These models work synergistically to optimize the system size and operation for maximum net present value (NPV) using lifetime economic costing and future electricity price signals generated by the National Renewable Energy Laboratory (NREL) ReEDS model and the Princeton University GenX model. In total, 4 unique thermal storage configurations were evaluated. The National Energy Technology Laboratory (NETL) Case B31B using Shell CANSOLV® CCS was assumed to be the base power plant in this study. To understand

* Corresponding author: Dr. Todd Bandhauer. Tel.: +1-970-491-7357, *E-mail address:* tband@colostate.edu

the feasibility of next generation CCS technologies, ION Clean Energy's ICE-31 solvent was also evaluated with the NETL Case B31A NGCC base power plant (B31A+ION CCS).

Keywords: Carbon Capture, Thermal Energy Storage, Natural Gas Combined Cycle, Future Electriciy Grids, Optimization

Nomenclature

ARPA-E	DOE's Advanced Research Projects Agency–Energy
B31A	NGCC power plant specified by NETL
B31B	NGCC + CCS power plant specified by NETL
CAISO	California Independent System Operator
CAPEX	Capital Costs Expenses
DOE	Department of Energy
CCS	Carbon Capture and Storage
EES	Engineering Equation Solver
FOM	Fixed Operating and Maintenance
ERCOT	Electricity Reliability Council of Texas
HRSG	Heat Recovery Steam Generator
HSSG	Hot Storage Steam Generator
LCOE	Levelized Cost of Energy
MISO	Midcontinent Independent System Operator
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NGCC+CCS	NGCC Power Plant with Carbon Capture and Storage
NGCC+CCS+TES	NGCC Power Plant with Carbon Capture and Storage and Thermal Energy Storage
NREL	National Renewable Energy Laboratory
PJM	Pennsylvania, New Jersey, and Maryland
OPEX	Operational Expenses
TES	Thermal Energy Storage
VOM	Variable Operating and Maintenance

1. Introduction

Across the world there are a multitude of climate goals designed to reduce the impact of global warming in the coming years. Most of these goals center around reducing greenhouse gas emissions, particularly carbon dioxide (CO_2) [1–4]. As such, the electricity market infrastructure is undergoing a shift that will significantly reduce its carbon dioxide emissions. Most new electric generating capacity utilizes renewable resources because wind turbines and solar panels have become inexpensive as their technologies have matured [5,6]. Additionally, various policies have been implemented that seek to control the quantity of carbon dioxide emitted by fossil fuel generators [7–10]. In coming years, both renewable energy generation capacity, and the severity of emissions policies are expected to continue to increase [11,12]. These changes will restrict the capabilities of existing fossil fuel power plants by forcing them to operate flexibly and at lower capacity factors, while penalizing them for emitting CO_2. However, state of the art fossil fuel plants will remain an important asset to the energy market because they are a less expensive solution than batteries to supplement intermittent renewable generation and they offer a margin of safety in capacity reserve and ensure grid stability [6,13]. By incorporating carbon capture and storage (CCS), total CO_2 emissions from fossil power plants can be reduced up to 99%, while retaining important grid services [14,15]. Unfortunately, CCS technologies are capital intensive and their operation requires a large parasitic heat load from the power plant for the carbon capture solvent regeneration process [16]. This solvent regeneration process is essential to separate and store the captured CO_2 from the chemical-based solvent, but in doing so requires an immense amount of heat from the power plant. This energy load subtracts from the maximum power that can be delivered to the electricity grid and reduces the power plants capability to operate flexibly. Meanwhile, the electricity grid is expected to become more volatile since the electricity selling price will be low during periods of high renewable output and high when renewable generation cannot meet electricity demand. Therefore, there is financial incentive to increase the flexibility of power plants with CCS to respond better to rapid changes in the pricing and demand structure of the grid.

Many methods have previously been investigated to increase the flexibility of power plants with CCS. These primarily include carbon capture unit bypass, solvent storage, hydrogen storage, and oxygen storage [17–26]. Each method has been shown to increase the power plant generation capacity during periods of peak electricity demand. This enables an increase in revenue from electricity sales because higher quantities of electrical power can be sold when the electricity price is at a maximum. However, previous investigations have also shown limitations of each approach. By bypassing the carbon capture unit at times of peak demand and prices, the parasitic power of the carbon capture unit can be avoided, but all the produced carbon dioxide is vented to atmosphere. This significant increase in CO_2 emissions has a devastating economic impact when severe emissions policies are in effect [20]. Solvent storage technologies increase the CCS power draw during times of low demand and prices, to offset the parasitic penalty during times of high revenue and prices without increasing CO_2 emissions. However, solvent storage technologies have large capital costs which prevent them from being an economically viable option in future market scenarios [20]. Both hydrogen and oxygen storage technologies can also offset the parasitic power load associated with carbon capture and have shown the potential to be more economical than solvent storage. However, hydrogen and oxygen storage technologies are only compatible with integrated gasification and oxy-combustion power plants, respectively, which are not abundant in the current electricity market. As such, significant capital investment is required to move these proposed technologies through the required development stages to become reality. Therefore, there is incentive to explore new technologies that are applicable to current state of the art fossil fuel power plants such as natural gas combined cycles (NGCCs).

Although thermal energy storage (TES) has been explored extensively in the context of power generation, coupling TES with carbon capture is a novel concept and the exploration of its financial feasibility has only recently been investigated [27]. Limb et al. evaluated fifteen different TES configurations using historical locational marginal pricing structures from the New York Independent System Operator (NYISO) and California Independent System Operator (CAISO) electricity markets. They concluded that TES can be an economically viable option for flexible carbon capture, and that the top three best performing configurations included extracting steam from the heat recovery steam generator (HRSG) of the NGCC, using a vapor compression heat pump sourced by the NGCC exhaust, and using a tiered vapor compression heat pump that simultaneously generates hot and cold storage. A vapor compression refrigeration cycle used to generate cold storage was also deemed to be economically valuable when operated in combination with the steam extraction and flue gas heat pump designs.

In addition to identifying the three best performing configurations, Limb et al. found that low capital costs and the ability to charge the hot TES independent of the NGCC operation was valuable. As such, the current study evaluates the feasibility of a novel low-cost resistively heated hot TES design and compares it to the three best performing configurations identified previously. Additionally, future electricity pricing scenarios from the National Renewable Energy Laboratory (NREL) and Princeton University, both in the U.S.A., were used to better evaluate operation in future decarbonized electricity grid scenarios. This study also builds upon the previous work by incorporating a control co-design and optimization model which optimizes the electricity dispatch strategy and the capacity of the configuration components to increase overall net present value (NPV) of the system.

2. Methods

The methods are broken down into the four subsections representing each component necessary for the completion of this analysis. Evaluation of the proposed thermal storage technologies required three interconnected models to simulate the power plant's operation and evaluate the economic feasibility of TES coupled with NGCC+CCS. These models include a technology model which simulates the thermodynamic performance of each of the key components (NGCC, CCS, and TES), an optimization model which determines how the power plant should operate based off a given electricity price signal and calculates optimum TES storage sizing, and an economics model which evaluates the NPV of the system based off the profits and costs (including all capital and operational costs). Descriptions of the each of these models are presented in the following sections. The first subsection details the technology model, the four TES configurations, and the two CCS technologies used in this study. The second subsection details the optimization model. The third subsection details the economics model. The fourth subsection provides an overview of the future electricity price signals used to perform this analysis.

For all TES configurations, the NGCC+CCS+TES's operation mechanics are dependent on whether the TES units are charging, discharging, or neutral (Fig. 1). The "neutral phase" refers to the operation mode where the power plant is running as a standard NGCC+CCS plant and no charging or discharging of thermal storage is taking place. During the "charging phase", net power plant output is decreased and the extra energy is used to charge the thermal storage reservoirs. Charging of the TES units can be done via heat from the NGCC or grid electricity depending on the configuration. Configurations that charge using grid electricity can charge during periods when electricity prices are near zero for greater arbitrage opportunity. During the "discharge phase", peak power output is being sent to the grid and both thermal storage reservoirs are being depleted. The hot TES is providing steam to the CCS unit and cold TES is chilling the ambient air entering the NGCC to increase combustion efficiency. Last, there is an additional "boost phase," which is only available for configurations that include an independently refrigerated cold storage and refers to the operation mode where the cold TES is simultaneously being charged and discharged. For some configurations, this results in a slight power boost above the neutral power output and incurs an increase in natural gas consumption.

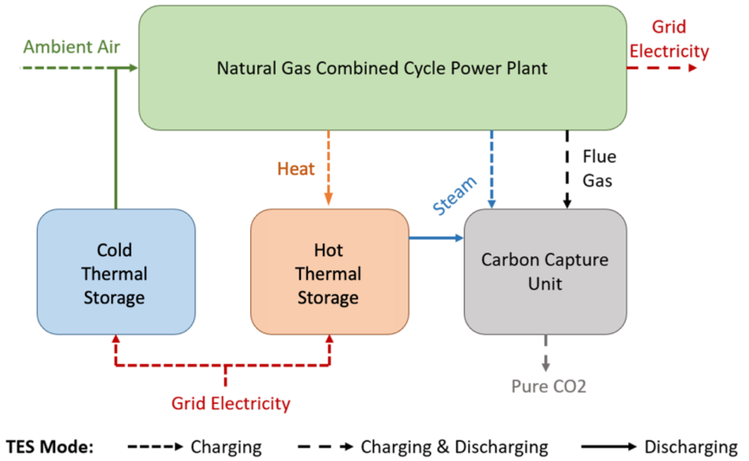

Fig. 1. Concept of integrating thermal energy storage on a natural gas combined cycle power plant with carbon capture and the associated operation modes. Note some thermal storage concepts only use heat or grid electricity for hot thermal storage charging not both.

2.1. Technology Model & TES Configurations

The technology model is designed to simulate the key components of the NGCC+CCS+TES configurations in the different phases of operation. The following paragraphs detail how each of the main components (NGCC, CCS, and TES) are modeled and validated.

The base power plant selected for this analysis was the NGCC power plant with CCS as specified in the National Energy Technology Laboratory's (NETL) 2019 report (Case B31B) [14]. The TES configurations were coupled with the base power plant and compared to the base power plant without TES to determine the value of TES when used with CCS. A thermodynamic model of this plant was constructed in Engineering Equation Solver (EES) to properly represent the effect that each TES configuration has on the base plant's operation. This model calculates the heat transfer, power production/consumption, and thermodynamic states on either side of the primary components (heat exchangers, pumps, compressors, turbines, etc.) for both the gas and the steam cycles. The model assumes constant volumetric air flowrate, combustor temperature, heat of combustion, and component isentropic efficiencies. For validation of the model, the net power output and flowrates of the gas and steam plant calculated in the model were compared to those specified by the NETL report. All calculated values were within 5% of the specified NETL value.

To evaluate the TES configurations, models were created for each of the individual configurations. Like the base model, the surrogate models calculate the heat transfer, power consumption/production, and thermodynamic states of the main heat pump components, including the storage mediums, heat exchangers, compressors, turbines, expansion valves, and pumps. The surrogate models output the heat rate to/from the thermal storages, flow rates of the working fluids, total mechanical power required to run individual configurations, and sizes of each component. The TES medium was assumed to be concrete and was based off those designed by Storworks Power [28].

The base NGCC+CCS model was modified to incorporate the charging and discharging modes of TES operation. During the charging mode, the working fluid streams in the base model were adjusted to account for the fluid extraction in the TES configuration and re-combination at the corresponding location in the base plant. During the

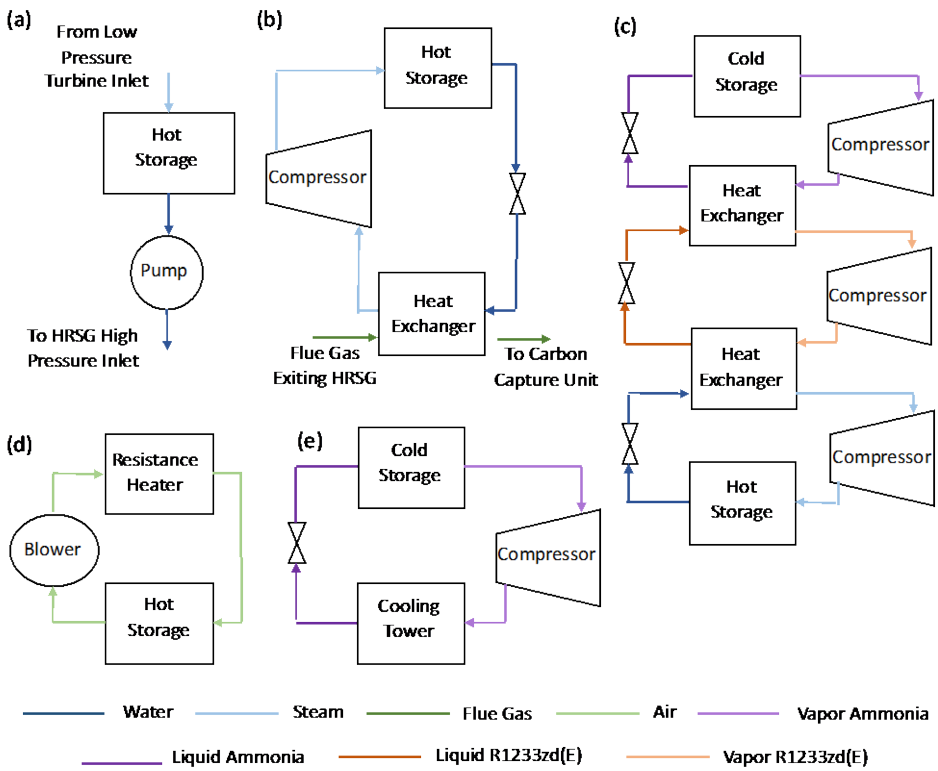

Fig. 2. Overview of the hot and cold thermal energy storage configurations evaluated in this study. These configurations include (a) extracting steam from the NGCC's heat recovery steam generator and storing the hot steam energy [HRSG Steam] (b) vapor compression heat pump using flue gas from NGCC to provide heat [Heat Pump VC] (c) tiered vapor compression heat pump which generates and stores heat from grid electricity [Tiered VC] (d) using resistive heating and grid electricity to generate and store heat [Resistive Heating] and (e) refrigeration heat pump to store cold thermal energy [Cold TES].

discharging mode, the hot storage is used to provide the CCS reboiler steam requirement. As such, the steam used for the CCS reboiler during normal operation is instead routed through the low repressure turbine in the NGCC's HRSG, consequently increasing power output for all configurations. The cold storage heat rate is used to calculate increased gas and steam flowrates. The total increase in gas and steam generator sizes and costs are calculated in discharging mode of the model.

This work evaluated four hot TES configurations: the three downselected TES configurations found by Limb et al. and a novel low-cost resistively heated hot TES design [27]. Diagrams of the four hot TES configurations can be seen in Fig. 2 as can the cold TES design used for this work. The presented cold TES was added to all hot TES configurations except the tiered vapor compression approach. The tiered vapor compression approach generates cold thermal energy natively. The TES configurations include: 1. extracting steam from the NGCC's heat recovery steam generator and storing the hot steam energy (HRSG Steam) 2. vapor compression heat pump using flue gas from NGCC to provide heat (Heat Pump VC) 3. tiered vapor compression heat pump which generates and stores heat from grid electricity (Tiered VC) and 4. using resistive heating and grid electricity to generate and store heat (Resistive Heating).

In addition to the configuration design, the primary differences between the TES configurations are their heat source, CAPEX, round trip efficiency, and their storage volume (Table 1). Storage volume differs between configurations because the maximum temperature delta in the heat exchanger is configuration dependent with higher temperatures resulting in smaller volume. Configurations that store heat from the NGCC have a higher round trip efficiency, but also have increased capital costs. Configurations that use grid electricity for heating have a reduced round-trip efficiency, but the resistive heating configuration also has the benefit of reduced CAPEX and small storage volume.

Table 1. Key parameters of the technology configurations evaluated.

TES Configuration	HRSG Steam	Heat Pump VC	Tiered VC	Resistive Heating
Capex (MM$)	24.01	38.85	98.53	19.73
Round Trip Efficiency	56%	59%	41%	27%
Storage Volume (1000 m^3)	20.62	24.81	30.59	11.19
Heat Source	NGCC Steam	NGCC Flue Gas	Decarbonized Grid	Decarbonized Grid

This research considered two carbon capture technologies. Case B31B uses Shell's proprietary and patented CANSOLV® CO_2 capture technology [29]. As such, all assumptions listed for the CCS unit in the NETL report were used for CANSOLV® in this analysis. Additionally, ION Clean Energy's ICE-31 solvent was evaluated as a next generation CCS technology [30]. Both are proprietary solvent absorption technologies that have the similar operation principles. As such, the CCS unit in the technology model was represented as a black box with clearly defined inputs and outputs. These inputs and outputs include: flue gas flowrate, composition, and temperature; steam flowrate, temperature, and pressure; CO_2 capture percent and electricity requirement; and CAPEX and OPEX. The CCS unit performance was validated for CANSOLV® CCS using the NETL 2019 report. CCS parameters were adjusted for ION CCS based on publicly available data. The primary difference between the two technologies is that ION CCS has a 38% reduction in CAPEX, 28% reduction in OPEX, and capture rate of 99% (compared to 90% for CANSOLV® CCS) [15,30]. The CCS steam reboiler duty and electrical parasitic load were held constant for all operation modes. Since the steam reboiler duty is held constant, the percent of CO_2 sequestered was assumed to vary with natural gas flowrate according to data in the literature [31,32].

2.2. Optimization Modeling

The optimization model is designed to simulate the behavior of a NGCC+CCS responding LMP electricity price signals by making hourly dispatch decisions. The design and operation of this model builds upon the dispatch methodology used by Limb et al and incorporates the optimization framework created by Vercellino et al. [27,33]. In addition to simulating the NGCC+CCS behavior, the optimization model optimizes TES sizing to maximize NPV. Fig. 3 provides an example of the NPV benefit that can be seen by incorporating optimization into TES sizing. In this example, the optimization found that both longer hot and cold TES durations resulted in an increase in NPV of $35 million. Optimization was performed using both the base NGCC+CCS power plant and the NGCC+CCS+TES system to determine the economic benefit provided by TES. Additionally, optimization was performed on all electricity price signals independently such that optimum design and operation could be found in all scenarios.

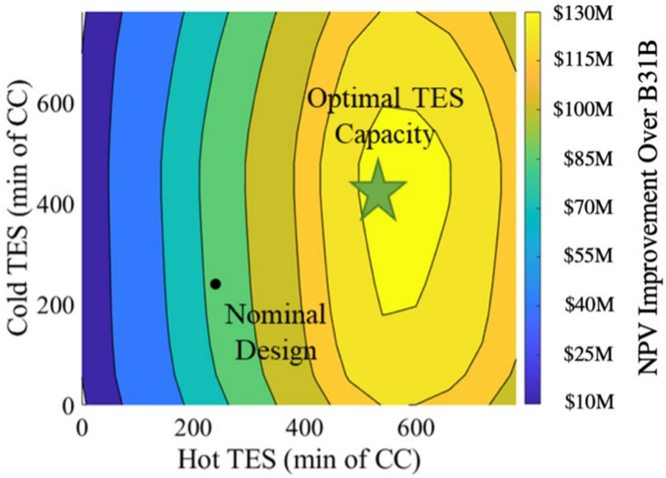

Fig. 3. Example of the impact on NPV by optimizing both hot and cold thermal energy storage (TES) capacities.

2.3. Economic Modeling

A 30-year discounted cash flow analysis was used to evaluate which TES technology had the highest NPV based on simulations of the power plant using future electricity grid pricing. NPV was selected as the primary economic metric over other commonly used indicators such as levelized cost of electricity (LCOE) because NPV accounts for variations in the electricity pricing structure, which are critical to understand the benefit of storage technologies. LCOE does not account for these variations. Standard economic assumptions are used and presented in Table 2 [34,35]. All dollar values were adjusted to December 2018 dollars based on historical inflation rates as calculated by the Bureau of Labor Statistics using the Consumer Price Index [36].

Table 2. Economic Analysis Assumptions

Item	Value	Units	Source
Loan Interest Rate	5	%	ABT
Loan Term	30	years	ABT
Financed Amount	80	%	ABT
Equity Amount	20	%	ABT
Construction Interest Rate	3.5	%	ABT
Construction Period	3	Years	ABT
Construction Build Rate	80, 10, 10	%	ABT
MARCS Depreciation	15	Years	ABT
Tax Rate (Federal and State	25.7	%	ABT
Internal Rate of Return	10	%	ABT
Natural Gas Price Increase	3.5	%/year	EIA
Price Increase	2.2	%/year	EIA

Cost assumptions for each of the technologies varied by the individual components. Depending on the components that were added or removed for a given system, the prices of the components were scaled accordingly. All costs associated with new TES components were based on the same components used within NETL's B31B power plant. Similarly, when the CCS unit was scaled to accommodate the higher power outputs, costs were scaled based off the CANSOLV® CCS system used for B31B. Lastly, thermal storage component costs were based on Storworks' project capital costs of $25/kW-thermal for a 100° K temperature change during charging/discharging [28]. Both fixed and variable operation costs were based on the values provided by NETL for B31B and scaled depending on the thermal storage configuration. All system components were assumed to last a 30-year life, except those replaced through routine maintenance.

2.4. Electricity Price Profiles

In total, fourteen electricity market scenarios were evaluated in this study, all of which include one year of hourly electricity prices. Four electricity market scenarios were generated by Princeton and MIT's GenX capacity expansion model and ten scenarios were generated by NREL's ReEDs capacity expansion model [11,12]. The GenX scenarios utilize a CO_2 tax of $60 per tonne and represent a possible mix of future generators (i.e. high amounts of wind or solar generation). The ReEDs scenarios consider existing regional electricity markets under carbon taxes of $100 per tonne and $150 per tonne of CO_2. All fourteen electricity price signals are meant to simulate future electricity grids with high renewable energy deployment. A summary of the electricity price scenarios is shown in Table 3.

Table 3. Summary of the future electricity market scenarios evaluated.

Scenario Name	Source	Model	CO_2 Tax ($/tonne)	Situation/Region
G60-Base	Princeton	GenX	60	Base Case
G60-HighWind	Princeton	GenX	60	High Wind Generation
G60-HighSolar	Princeton	GenX	60	High Solar Generation
G60-Winter	Princeton	GenX	60	Winter/New York
R100-CAISO	NREL	ReEDS	100	California Independent System Operator
R150-CAISO	NREL	ReEDS	150	California Independent System Operator

Scenario Name	Source	Model	CO_2 Tax ($/tonne)	Situation/Region
R100-ERCOT	NREL	ReEDS	100	Electricity Reliability Council of Texas
R150-ERCOT	NREL	ReEDS	150	Electricity Reliability Council of Texas
R100-MISO	NREL	ReEDS	100	Midcontinent Independent System Operator
R150-MISO	NREL	ReEDS	150	Midcontinent Independent System Operator
R100-NYISO	NREL	ReEDS	100	New York Independent System Operator
R150-NYISO	NREL	ReEDS	150	New York Independent System Operator
R100-PJM	NREL	ReEDS	100	PJM Interconnection
R150-PJM	NREL	ReEDS	150	PJM Interconnection

3. Results

The results are broken down into two subsections representing the key findings of this analysis. The first subsection details the economic performance of the four TES configurations evaluated over future electricity price signals and includes a discussion on the value of optimization. The second subsection presents detailed NPV results for the Resistive Heating TES configuration working in conjunction with both CANSOLV® and ION CCS systems.

3.1. Economic performance of TES in Future Electricity Markets

Fig. 4 presents a NPV comparison between the four TES technologies evaluated and NETL's B31B power plant. Results also show the improvement in NPV gained through optimization (blue) vs the downselection TES sizing of 4 hours used by Limb et al. (orange) [27]. Results are separated between GenX and ReEDS future electricity price signals because of their varying assumptions and carbon taxes. All configurations incorporate Cold TES, but results focus on hot TES technologies since previous studies have shown Cold TES to be a valuable solution [37–42].

The results in Fig. 4 clearly show the economic value of adding TES to NGCC+CCS systems. On average, TES improved the NPV of the NGCC+CCS system by $67 million and $26 million for the GenX and ReEDS future price scenarios, respectively. Additionally, scenario specific optimization dramatically improved the NPV of the

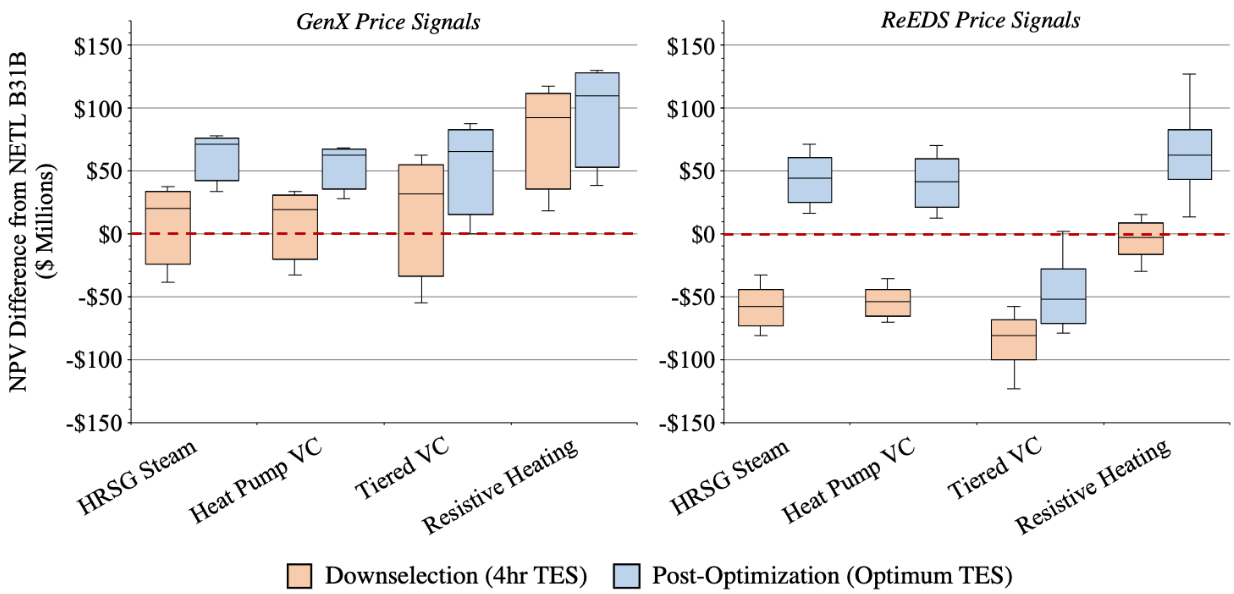

Fig. 4 . NPV comparison between the four thermal energy storage (TES) technologies evaluated for both GenX and ReEDS future electricity price signals compared to NETL's B31B power plant. Results are shown for the improvement in NPV gained through optimization (blue) vs the assumed scenario of 4 hours of TES (orange).

NGCC+CCS+TES system when compared to the downselection configurations used by Limb et al. [27]. Optimization improved the average NPVs by $38 million and $76 million for the GenX and ReEDS future price scenarios, respectively. There are two primary reasons why optimization had such a large impact. First, the dispatch strategy used is specific to each price profile, whereas previous work assigned the same operation strategy to each profile and configuration. Secondly, the TES component sizes are specific to each profile and configuration. For example, ReEDS price profiles are better suited for longer TES storage durations because of the longer periods of price variation. This is also why there is a larger gap between optimized and unoptimized results for the ReEDS pricing scenarios compared to the GenX ones. The nature of the GenX price signals result in optimized TES sizes near the 4 hours of duration assumed by Limb et al., but ReEDS price signals typically have optimized sizes closer to 10 hours of storage duration.

In all scenarios evaluated, Resistive Heating was the best performing TES configuration. Since the future scenarios in this study focused on situations with high renewable energy deployment, the lower round-trip efficiency associated with Resistive Heating was negated because since the TES could charge at very low electricity prices when renewable energy is plentiful. Alternatively, the HRSG Steam and Heat Pump VC configurations rely on the NGCC plant operation to charge their hot TES and therefore couldn't take advantage of low-cost renewable energy. Additionally, the Tiered VC configuration has the capability to charge using low-cost renewable electricity, but its high CAPEX costs only make it feasible in certain scenarios. For example, Tiered VC is the 2nd best performing configuration for the GenX scenarios, but the worst performing configuration for the ReEDS scenarios. Tiered VC also has the limitation that it has hot and cold combined storages which limits optimization potential since the hot and cold storages need to be sized together. Optimization results presented by Vercellino et al. show that the optimal hot TES duration is usually much larger than that of the cold TES because cold TES is used primarily for boosting [33]. Resistive Heating provides low CAPEX, independent charging from the NGCC, and seperate hot and cold storages at the expense of decreased efficiency. However, these results show that the downside of decreased efficiency is minimal in a future electricity market with plentiful low-cost renewable energy. Since Resistive Heating not only outperforms all other TES configurations, but also improves NGCC+CCS NPV in every scenario evaluated, it is recommended that Resistively Heated TES be added to NGCC+CCS systems when increased flexibility and profitability is desired.

3.2. TES Performance with Multiple CCS Technologies

Fig. 5 presents the NPV improvement of adding the Resistive Heating TES configuration to both NETL B31B (B31A with CANSOLV® CCS) and B31A with ION Clean Energy CCS. Subplots show NPV values compared to (a) NETL B31B to show the NPV improvement from adding TES and ION CCS or (b) NETL B31B (CANSOLV® CCS) and NETL B31A+ION CCS (ION Clean Energy CCS) to show the NPV improvement from TES only. NPV results in Fig. 5a show a dramatic increase in NPV when ION CCS is used. This is due to the reduced CAPEX and OPEX costs and increased carbon capture rate compared to CANSOLV® CCS. When NPV results are simplified to only show the impact of TES on NGCC+CCS performance (Fig. 5b), Resistive Heating + Cold TES is found to have a very similar impact regardless of CCS technology used. Minor differences between the results stem from the different steam requirements (flow rate & desired temperature) of each CCS technology. Higher required flowrates as are required by CANSOLV® CCS indicate higher capacity thermal storages and a higher potential for thermal storage to offset the parasitic load. Lower flowrates as are found using ION CCS indicate a more efficient CCS unit that doesn't require as much TES to offset the parasitic power.

The real value of TES can be seen when the NPV improvement on individual electricity market scenarios is evaluated. Table 4 shows NPV improvement or detriment of adding CCS and TES to NETL B31A (NGCC without CCS or TES). NPV values are provided for both NETL B31B (B31A with CANSOLV® CCS) and B31A with ION CCS. In three of the fourteen scenarios evaluated, TES made the difference between NGCC with CCS being more economical than a NGCC without CCS. In ReEDS price signals, B31B has a lower NPV than B31A for both R100-CAISO and R150-NYISO price signals. However, B31B+TES for the same price signals has a higher NPV than B31A. The same is seen for B31A+ION CCS vs B31A+ION CCS+TES on the GenX G60-HighWind scenario. Therefore, regardless of the CCS technology used, TES could be the difference between CCS technologies being economically feasible in future electricity markets.

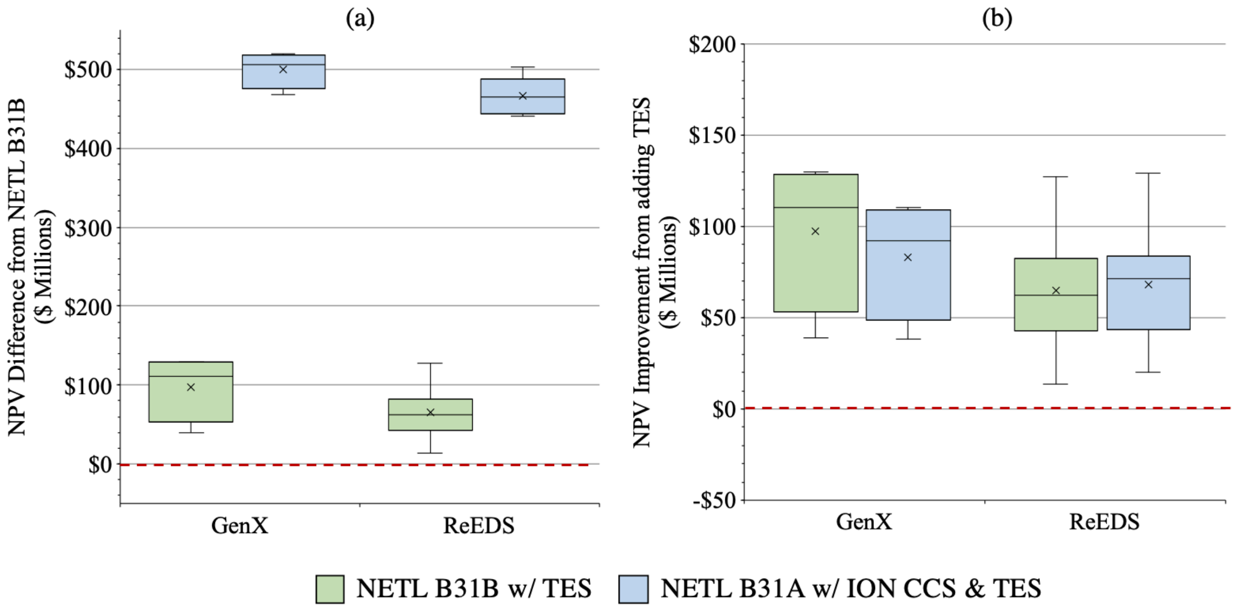

Fig. 5. NPV improvement of adding thermal energy storage to NGCC+CCS for both NETL B31B (B31A w/ CANSOLV® CCS) and B31A w/ ION Clean Energy CCS. NPV values are compared to (a) NETL B31B to show the NPV improvement from adding TES and ION CCS or (b) NETL B31B (CANSOLV® CCS) and NETL B31A+ION CCS (ION Clean Energy CCS) to show the NPV improvement from TES only.

Table 4. NPV improvement/detriment of adding carbon capture and storage (CCS) and thermal energy storage (TES) to NETL B31A (NGCC without CCS or TES). NPV values are provided for both NETL B31B (B31A with CANSOLV® CCS) and B31A with ION CCS. Highlighted rows identify scenarios where TES made NGCC+CCS become economical compared to a NGCC without CCS.

	Price Profile	B31B	B31B+TES	TES Impact	B31A+ION	B31A+ION+TES	TES Impact
GenX	G60-Base	($ 273 M)	($ 177 M)	+$ 96 M	+$ 144 M	+$ 225 M	+$ 80 M
	G60-HighWind	($ 433 M)	($ 303 M)	+$ 130 M	($ 24 M)	+$ 87 M	+$ 111 M
	G60-HighSolar	($ 344 M)	($ 219 M)	+$ 124 M	+$ 67 M	+$ 171 M	+$ 104 M
	G60-Winter	($ 213 M)	($ 174 M)	+$ 39 M	+$ 216 M	+$ 254 M	+$ 38 M
ReEDS	R100-CAISO	($ 9 M)	+$ 118 M	+$ 127 M	+$ 365 M	+$ 494 M	+$ 129 M
	R150-CAISO	+$ 115 M	+$ 222 M	+$ 107 M	+$ 490 M	+$ 603 M	+$ 113 M
	R100-ERCOT	($ 206 M)	($ 153 M)	+$ 53 M	+$ 235 M	+$ 281 M	+$ 46 M
	R150-ERCOT	+$ 21 M	+$ 69 M	+$ 48 M	+$ 429 M	+$ 477 M	+$ 48 M
	R100-MISO	($ 45 M)	($ 16 M)	+$ 29 M	+$ 361 M	+$ 397 M	+$ 36 M
	R150-MISO	($ 21 M)	($ 7 M)	+$ 14 M	+$ 404 M	+$ 423 M	+$ 20 M
	R100-NYISO	($ 158 M)	($ 84 M)	+$ 75 M	+$ 211 M	+$ 285 M	+$ 74 M
	R150-NYISO	($ 40 M)	+$ 30 M	+$ 70 M	+$ 332 M	+$ 405 M	+$ 72 M
	R100-PJM	+$ 118 M	+$ 182 M	+$ 63 M	+$ 521 M	+$ 593 M	+$ 71 M
	R150-PJM	+$ 361 M	+$ 422 M	+$ 61 M	+$ 779 M	+$ 851 M	+$ 72 M

4. Conclusions

Currently, fossil fuel-based power plants generate the majority of the United States' electricity and provide a reliable generation source for both base and peak power demands. However, future emissions standards are expected to require these power plants to use CCS, which has a detrimental impact on the power plant's performance. Therefore, this study built upon work completed by Limb et al. and evaluated four TES configurations designed to overcome the operational limitation placed on the NGCC by CCS due to the large heat load required for solvent regeneration [27].

Results from this analysis clearly show the economic value of adding TES to NGCC+CCS systems. On average, TES improved the NPV of the NGCC+CCS system by $67 million and $26 million for GenX and ReEDS future price scenarios, respectively. Additionally, a resistively heated hot TES system was found to be the best performing TES configuration in all future scenarios evaluated. Since the future scenarios in this study focused on situations with high renewable energy deployment, the lower round-trip efficiency associated with resistive heating was negated because the TES could charge at very low electricity prices when renewable energy was plentiful. Results confirmed previous findings which illustrated that low CAPEX is more important than increased round trip efficiency in future electricity markets. This study also evaluated the impact of TES on two CCS technologies: CANSOLV® CCS and ION Clean Energy's CCS. Results showed that TES has similar performance regardless of CCS system used. Further, ION CCS system was found to have a more efficient system design which results in a slightly reduced NPV benefit for TES because the ION system's regeneration parasitic load is smaller. Lastly, this work also found that TES can make the difference between CCS being profitable in future grid environments. In three of the fourteen scenarios evaluated, TES made the difference between NGCC with CCS being more economical than a NGCC without CCS. This is a key finding and should be investigated further in future studies.

Acknowledgements

The authors are grateful for financial support from the Department of Energy Advanced Research Projects Agency-Energy award number DE-AR0001306. Additionally, the authors acknowledge support from Kelli Morrill, Rori Limb, Owen Limb, and Danna Quinn.

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