# Nuclear Power Coupled With Thermal Energy Storage: Impact of Technical Performance on Economics in an Exemplary Electricity Grid

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*Thermal energy storage (TES) coupled with nuclear energy could be a transformative contribution to address the mismatch in energy production and demand that occur with the expanding use of solar and wind energy. TES can generate new revenue for the nuclear plant and help decarbonize the electricity grid. Prior work by the authors identified two technical approaches to interface TES with nuclear. One, termed the primary cycle TES, charges and discharges the TES within the main Rankine power cycle. The second, termed the secondary cycle TES or SCTES, discharges the TES to a secondary power cycle. The present work analyzes the potential economic benefits of TES in an arbitrage market for a 1050 MW$_e$ nuclear plant. The study is the first to provide a realistic quantification of the impacts of changes in capacity factor due to use of TES on revenue and internal rate of return (IRR). The analysis is for a three-year period for peaking powers from 120% to 150% of the conventional nuclear plant for an exemplary deregulated utility represented by the Electric Reliability Council of Texas (ERCOT). The SCTES consistently provides the highest revenue and IRR. The benefits increase with increasing use of TES and variability of electricity prices. The results provide a technically sound understanding of the effects of how TES is integrated with nuclear power on economics and strong economic support for pursuing design and implementation of the SCTES.* [DOI: 10.1115/1.4053419]

*Keywords: economic, energy, energy storage, fan, compressor, and turbine aerodynamic design, nuclear power system simulations*

## 1 Introduction

The electricity grid is undergoing rapid changes with the addition of variable renewable energy (VRE) sources and implementation of policies to reduce greenhouse gas emissions. These changes and the need for greater resiliency of the electricity supply in the face of more extreme weather events create demand for greater flexibility of large power sources and expansion of storage on the grid. Capacity additions of wind and solar have outpaced the addition of more traditional thermal energy sources such as coal, natural gas, and nuclear in the USA since 2010. This trend shows no sign of abatement with a 1000% growth in VRE expected by 2050 [1]. The intermittent nature of VRE supply over both diurnal and seasonal time scales creates challenges to balance the supply of electricity with fluctuating demand. At high VRE penetration, there is risk of mismatch in supply and demand that cannot be addressed simply with existing natural gas fired power plants. One solution when supply exceeds demand is to curtail VRE generation, but curtailment increases the cost of renewable electricity. At 80% VRE penetration, curtailment could exceed 120 TW h annually [2].

To support the advancement of VRE supply to 50%, it is projected that 140 GW$_e$ of energy storage will be needed in the USA [3]. A host of energy storage devices are available to provide a wide range of energy services from instantaneous grid stabilization to long term, diurnal and seasonal load shifting [4–7]. It is likely a combination of these technologies and new innovations in long-term storage [8] will be deployed in the future. Currently, the majority of utility-scale energy storage deployed in the USA is pumped hydro storage, but expansion of pumped hydro has stalled due to geographical restrictions [9], low natural gas prices, and public policy barriers [10]. Batteries and the associated power electronics are relatively expensive at present [11]. New electrochemical storage technologies, such as reverse solid oxide cells, may provide greater economic benefit in the future [8]. Another option is thermal energy storage (TES) for solar thermal and conventional thermal energy sources. TES could potentially provide large-scale energy storage at an order of magnitude lower cost than lithium-ion batteries [6,12–14].

Here we consider TES for nuclear power plants as a means to provide baseload flexibility and more favorable economics, and thus to help decarbonize electricity production [15,16], which is a leading source of direct carbon-dioxide emissions [17]. Figure 1 illustrates operation of a nuclear power plant with TES. When VRE generation is high, steam is diverted from the main power cycle and thermal energy is stored (red line). When VRE generation is low or unavailable, energy stored in the TES is used to generate steam to augment baseload power plant generation (green line). These two processes are referred to as charging and discharging the TES. The manner in which TES is integrated with the nuclear power cycle affects the capacity factor and the degree of flexibility that can be achieved [18–20]. This fact was neglected in prior economic analyses.

Curtis et al. [21] provided a qualitative description of the relative benefits and disadvantages of a number of options for TES coupled with nuclear power. Integration options fall into two categories, either discharge to the primary (existing) Rankine cycle or discharge to a secondary cycle. Gilli and Beckman [22] compared the cost of power of traditional peaking sources such as simple and combined cycle gas turbines to TES using steam accumulators that are

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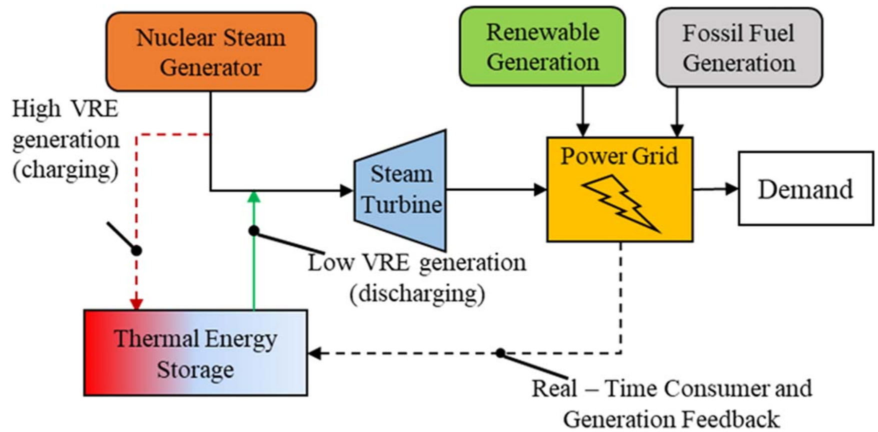


**Fig. 1 TES integrated with nuclear power to help meet peak demand and smooth transients created by the variability in the generation of renewable energy and demand**

discharged to a secondary cycle. Assuming 8% efficiency of conversion of heat from the steam generator to electricity from TES, they estimate TES could produce lower cost power than other peaking sources. Forsberg et al. [12] were early advocates for TES to mitigate the impact of lower price electricity on the economic viability of nuclear power plants. They estimated that storage requirements for nuclear energy in California would be 4% of daily nuclear generation compared to 36% and 21% for wind and solar, respectively [23]. Denholm et al. [15] quantified the potential for increased capacity factor of a nuclear power plant with storage compared to load reduction. They estimated that storage would increase the capacity factor of a nuclear power plant by 2.5% with a renewable penetration of 60% and discharge power equal to 110% of the nominal baseload. Borowiec et al. [24] considered TES to increase the revenue of nuclear power plants in US electricity markets through capacity payments, arbitrage, and ancillary services.

In the prior economic studies, TES was assumed to provide flexibility without sacrificing efficiency of the power cycle. This assumption is incorrect. Carlson and Davidson [18,19] and Carlson et al. [20] applied a thermodynamic model of a modern 1050 $MW_e$ pressurized water nuclear power plant to quantify the impact of how TES is integrated and operated within the power cycle on efficiency and capacity factor of the plant. They showed that TES penalizes efficiency of the Rankine cycle, but penalty can be ameliorated with consideration of how the TES is integrated into the cycle and how charging and discharging of the TES are handled. The present study shows that TES can provide a significant economic benefit if it is configured to minimize the penalties.

Two TES/nuclear configurations emerged from the technical modeling as the most favorable from the standpoint of maximizing efficiency and the ability to operate over a wide range of discharge or peaking power [18–20]. In the primary cycle TES (PCTES), the TES is integrated directly into the primary Rankine cycle for both charge and discharge. The TES is charged with high-pressure steam from the conventional steam generator. During discharge, steam is generated in the TES and then expanded in the low-pressure turbine (LPT) to provide peaking power. There are efficiency penalties during charge and baseload operation because of the requirements to reduce mass rate to the turbines during charging and to increase the size of the turbines to accommodate higher mass flowrates during discharge. The latter creates the necessity to operate the turbines in an off-design condition during baseload operation.

In the secondary cycle TES (SCTES), the TES is charged by steam diverted downstream of the high-pressure turbine (HPT) and moisture separator/reheater. During discharge, steam generated in the TES is passed through a secondary steam Rankine cycle. This option does not require modification of the primary cycle turbines and thus the efficiency of baseload operation is the same as the efficiency in conventional baseload operation.

The present study answers two key questions for the two TES/nuclear configurations. Does a nuclear plant with TES generate more revenue than the conventional plant? Is there a favorable rate of return for the incremental cost of adding storage to a plant? These questions are answered with consideration of changes in the technical performance of the plant imposed by TES and for an exemplary unregulated grid in the USA. The results prove the importance of maintaining high efficiency, particularly during baseload operation, and the role of price structure in profitability.

## 2 Approach

This section describes the two TES configurations, justifies the selections of the grid and TES operating conditions for modeling, and describes the economic analysis method.

**2.1 Power Plant Configurations.** The baseline nuclear power plant is the Westinghouse AP1000 pressurized water reactor. It was chosen because performance data are published [25] and it is representative of modern reactors in the USA. Figure 2 is a simplified diagram of the conventional steam Rankine cycle without TES. Steam exits the steam generator at constant temperature (271 °C), pressure (55 bar), and mass flowrate (1886 kg $s^{-1}$) and is expanded in the HPT to 10.5 bar (quality, $\chi = 0.88$). Using steam extracted from the HPT, steam is reheated to 251 °C (9.5 bar) before entering the LPT. Steam enters the condenser at 0.1 bar and $\chi = 0.88$, exiting at 44 °C. Baseload operation of the power cycle without TES generates 1050 $MW_e$ at a thermal efficiency of 31%.

Figure 3 is a schematic of the PCTES in which TES is integrated with the primary cycle of the AP1000. A more detailed schematic and description of operation is provided in Ref. [20]. An overview of operation is provided here for the convenience of the reader. This configuration was selected because it can provide significant peaking power and is an option that does not require a secondary cycle. When it is desirable to reduce baseload power, steam is diverted at the steam generator, upstream of the HPT to charge the TES. During charging, off-design operation of the HPT and LPT reduces turbine efficiency. The reduction in efficiency depends on the charging rate. Steam enters the TES at 271 °C and 55 bar. Energy is stored as the steam is cooled isobarically to 46 °C. During discharge, stored condensate is pressurized and heated in the TES to produce superheated steam that is combined with the steam exiting the moisture separator/reheater to increase the mass flowrate of the steam to the LPT. The requirement that the LPT be modified to handle higher mass flowrates than the conventional cycle imposes lower efficiency during off-design baseload operation. The efficiency penalty of TES depends on the discharge power.

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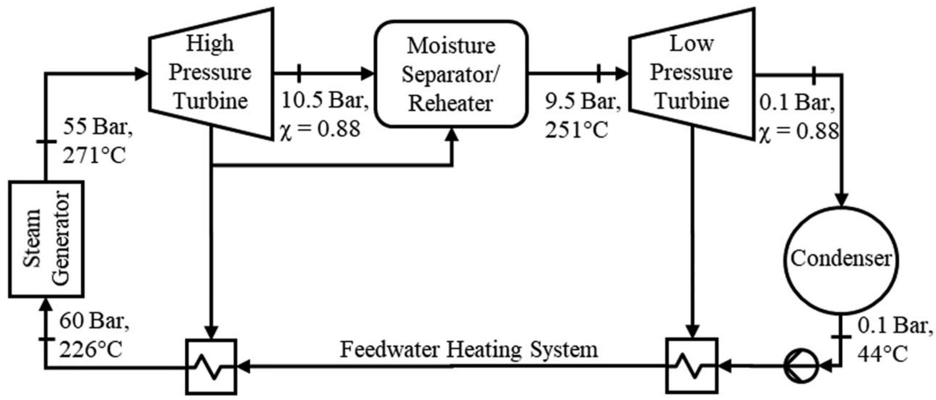


**Fig. 2 Simplified diagram of the conventional AP1000 without TES. Key inlet and outlet state points are indicated.**

Figure 4 is a simplified schematic of the SCTES in which the TES is discharged to a secondary Rankine cycle. A more detailed schematic and description are provided in Ref. [18]. The turbines in the primary power cycle do not require modification and thus there is no penalty to the efficiency of baseload operation. This later benefit is a key attribute of the SCTES. To charge the TES, steam is diverted downstream of the HPT after the moisture separator/reheater. The efficiency of the LPT decreases with increasing diversion of steam to the TES. There is no change in operation of the HPT. Steam enters the TES at 251 °C and 9.5 bar and exits at 46 °C. The TES discharges steam at 231 °C and 5.8 bar [25]. Stored condensate is pressurized and heated in the TES to produce superheated steam at 251 °C and 5.8 bar.

**2.2 Selection of Operating Conditions.** The capacity and efficiency of the PCTES and SCTES for a range of parameters including charge duration, discharge duration, discharge power ratio (DPR), and round-trip efficiency of the TES were quantified by Carlson and Davidson [18,19] and Carlson et al. [20]. The DPR is the ratio of power generated during TES discharge and the power generated by the conventional plant without TES. The round-trip efficiency is the ratio of thermal energy discharged from the TES and the thermal energy stored during charge. The capacity is described by the diurnal energy production ratio (EPR), which is the ratio of energy generated by a plant with TES to that generated by a conventional nuclear plant without TES. Results used in the present study are plotted in Fig. 5 for DPR up to 1.5, a TES round-trip efficiency of 90%, and charge/discharge durations of 4/3 h. Ninety percent round-trip efficiency is justified based on TES in concentrating solar power plants [34]. The selection of charge and discharge durations was guided by results of earlier studies of revenue from generic energy storage in a number of electricity grids [26,27,36]. A discharge duration of 3 h is also consistent with peak energy demand during summer months in California [28], where there is a rapidly growing fraction of VRE generation. Without TES, EPR is unity. With TES, EPR is less than unity with a higher fraction representing more efficient operation of the plant.

Both the PCTES and SCTES provide enormous flexibility for expansion of renewable energy sources in the power grid with achievable DPR values higher than other options considered in the prior technical evaluation [19]. The SCTES (dashed line) has the highest EPR over the full range of operating conditions considered but requires addition of a secondary cycle. The PCTES (solid line) requires a retrofit of both the HPT and LPT.

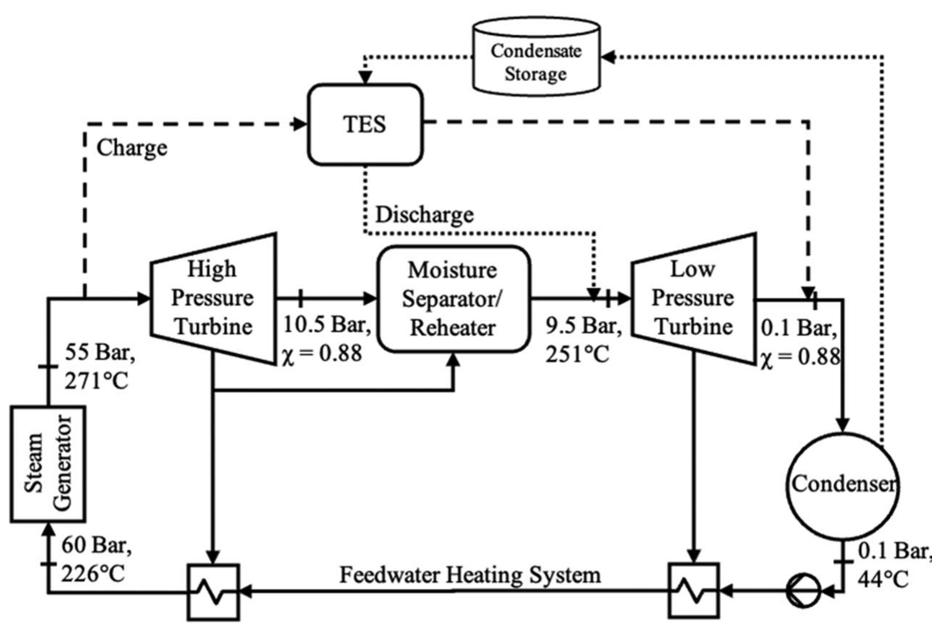


**Fig. 3 Schematic of the PCTES with charge and discharge from/to the primary cycle. TES charge is indicated by dashed lines. Discharge is indicated by dotted lines.**



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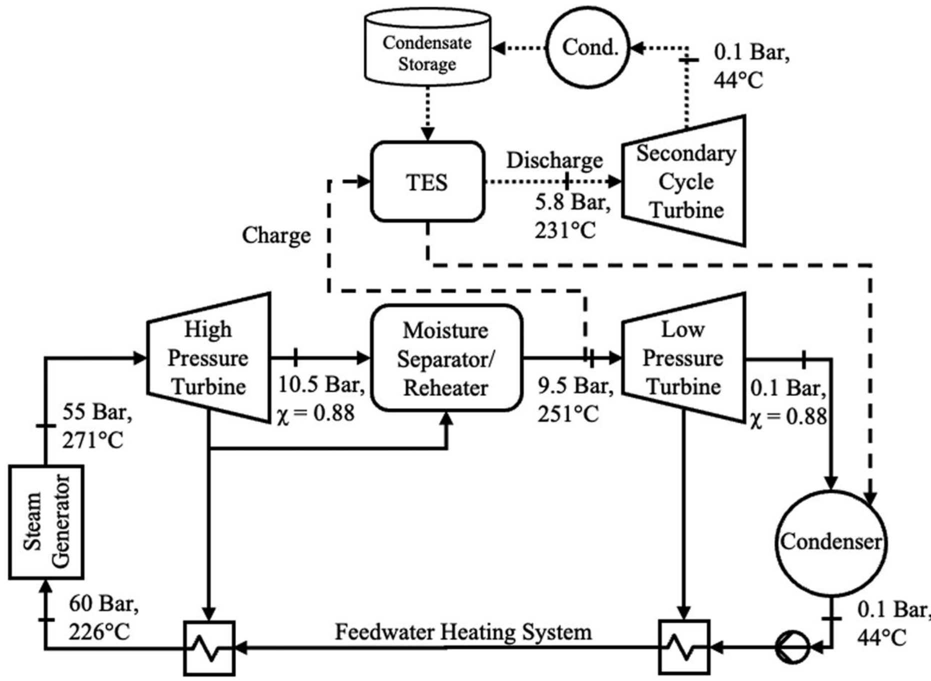


**Fig. 4 Schematic of the SCTES with charge from the primary cycle. Charge of the TES is indicated by dashed lines. Discharge is indicated by dotted lines to a secondary cycle.**

Revenue and internal rate of return (IRR) are predicted for DPRs of 1.2 and 1.5. The lower value of 1.2 is a target reported by Westinghouse [29]. The high value of 1.5 would provide greater flexibility and is feasible with existing turbine technology. Table 1 lists key performance attributes of the PCTES and SCTES for both DPRs. Values listed are EPR, diurnal thermal efficiency including charge, discharge, and baseload operation, the ratio of baseload power (BL) with TES and without TES during charging (subscript Ch), the ratio of power during charging and baseload operation, and the capacity of a rock bed storage to meet the specified DPR. The differences in the two TES options are notable during baseload, which is the mode of operation for the majority of the day, and charging. The baseload power of the conventional plant and the SCTES are identical. The baseload power of PCTES is 0.96 of that of a conventional plant at DPR = 1.2. At DPR = 1.5, power falls to 92% of the conventional plant. This reduction in baseload power is due to the need to oversize the primary turbines to accommodate additional steam during discharge of the TES. Charging occurs over 4 h and power drops compared to the conventional plant for both TES options. The power decrease is more substantial for the PCTES than SCTES. For example, at DPR = 1.2, the charging power ratio is 36% for the SCTES and 70% for SCTES. This difference is again due to the need to increase the size of the turbines in the primary cycle for the SCTES. Storage capacity is based on sensible heat storage in a rock bed. Sensible heat storage is the least expensive option for the storage temperatures required for nuclear power plants [19]. Latent heat storage materials using mixtures of salts at least double the cost of the storage material compared to rock. For DPR = 1.2, the storage capacity is about 3 GW $h_{th}$. Increasing the DPR to 1.5 increases the overall storage capacity requirements to 7.5–7.9 GW $h_{th}$.

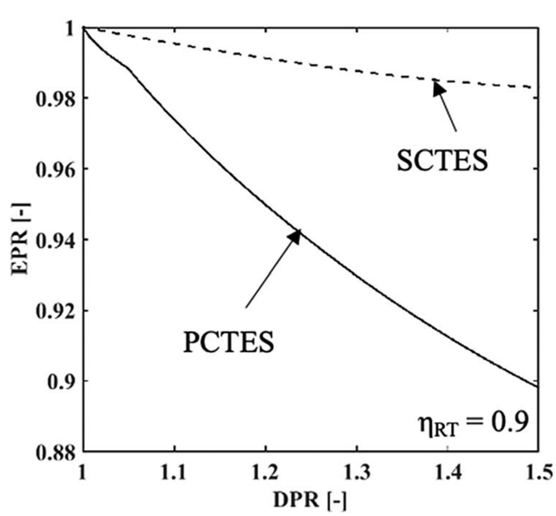


**Fig. 5 The diurnal EPR versus DPR for the SCTES (solid) and the PCTES (dashed) for TES round-trip efficiency of 90%, and charge/discharge durations of 4 and 3 h, respectively [19]. DPR is the ratio of power during TES discharge and the power of a conventional plant without TES. The round-trip efficiency is the ratio of thermal energy discharged to that stored. The diurnal EPR is the ratio of energy with TES to that of a conventional plant without TES.**

### 2.3 Revenue Model.

The revenue is calculated for the Electric Reliability Council of Texas (ERCOT), which manages a grid that serves 22 million customers with 85% of the state's electric load. ERCOT has a deregulated structure with few interconnections so the price for electricity fluctuates with the market and there is no impact of the import or export of power on price. It had 20% penetration of VRE in 2020 [30]. Revenue is analyzed for 2018–2020. The price of electricity is publicly available in 15-min increments [31].

The monthly revenue ($R$) is a sum of the revenue for each mode of operation as given by Eq. (1) from the first day of the month ($d = 1$) to the final day ($d_f$).

$$R_{\mathrm{TES}} = \sum_{d=1}^{d_f} \left[ \sum_{t_{D,s}}^{t_{D,s}+2} (\mathrm{DPR}) \dot{W}_{\mathrm{BL,conv}} P(t_D) + \sum_{t_{D,s,d-1}+2<t_{\mathrm{Ch},t}<t_{D,s,d}-3}^{t_{\mathrm{Ch},s}+3} \dot{W}_{\mathrm{TES},C} P(t_{\mathrm{Ch}}) \right] + \sum_{t=1}^{t_f - t_{\mathrm{Ch}}, t_D} \dot{W}_{\mathrm{BL}} P(t) \quad (1)$$



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Table 1 Performance attributes of the PCTES and SCTES for DPR = 1.2 and DPR = 1.5, 90% round-trip TES efficiency, and charge/discharge durations = 4/3 h

| Configuration | EPR | Plant $\eta$ (%) | Baseload power ratio, $\dot{W}_{\mathrm{TES,BL}}/\dot{W}_{\mathrm{conv,BL}}$ | Charge power ratio, $\dot{W}_{\mathrm{TES,Ch}}/\dot{W}_{\mathrm{conv,BL}}$ | TES capacity, $Q_{\mathrm{store}}$ (GW $\mathrm{h_{th}}$) |
|---|---|---|---|---|---|
| Conventional | 1.0 | 31.0 | Not applicable | Not applicable | 0 |
| *DPR = 1.2* | | | | | |
| PCTES | 0.95 | 29.5 | 0.96 | 0.69 | 3.00 |
| SCTES | 0.99 | 30.7 | 1.00 | 0.80 | 3.16 |
| *DPR = 1.5* | | | | | |
| PCTES | 0.90 | 27.9 | 0.92 | 0.36 | 7.50 |
| SCTES | 0.98 | 30.4 | 1.00 | 0.70 | 7.90 |

The time during the day for discharging (subscript $D$) is the time span with the highest 3-h average electricity price ($t_{D,s}$ to $t_{D,s}+2$). The revenue during this period is the product of the DPR, the conventional baseload power, and the electricity price. To maximize revenue, charging occurs during the 4-h period with the lowest electricity price between discharge periods, i.e., between ($t_{D,s,d-1}+2$) and ($t_{D,s,d}-3$). The revenue during charging is the product of the power of the cycle delivered to the grid and the price ($P(t_{\mathrm{Ch}})$) during this period. For the remaining 17 h of the day, the plant provides baseload power. For PCTES, the baseload power is reduced relative to a conventional plant without TES as indicated in Table 1. For SCTES, baseload power remains at the conventional value of 1050 $\mathrm{MW_e}$.

The annual revenue, $\bar{R}$, is the sum of the monthly values. Values for TES normalized by values for the conventional plant without TES are presented for monthly and annual time frames.

$$\phi = \frac{R_{\mathrm{TES}}}{R_{\mathrm{conv}}}, \quad \bar{\phi} = \frac{\overline{R_{\mathrm{TES}}}}{\overline{R_{\mathrm{conv}}}} \tag{2}$$

**2.4 Internal Rate of Return.** The IRR is the discount rate often used to evaluate the investment opportunity for a project. An investment is more attractive and less risky for higher IRR. The IRR is calculated based on the incremental revenue and cost associated with adding TES. It is expressed by Eq. (3) based on the annual revenue averaged over 2018–2020. The capital cost is the incremental cost of the TES and any modifications to the plant. $C_{\mathrm{O\&M}}$ is the annual incremental O&M and $N$ is the total lifetime of the investment. We consider $1 \le N \le 20$ years.

$$\sum_{y=1}^{N} \frac{1}{(1+\mathrm{IRR})^y} = \frac{C}{\overline{R_{\mathrm{TES}}} - C_{\mathrm{O\&M}}} \tag{3}$$

The capital cost includes the TES material ($C_{\mathrm{mat}}$), container ($C_{\mathrm{con}}$), and any modification of the power block ($C_{\mathrm{PB}}$) or secondary cycle for SCTES.

$$C_{\mathrm{TES}} = C_{\mathrm{mat}} + C_{\mathrm{con}} + C_{\mathrm{PB}} \tag{4}$$

Carlson and Davidson [19] provide an overview of different storage materials for sensible and latent storage. The narrow range of phase transition temperatures for this application limits the latent heat storage materials to relatively expensive salt mixtures, which are double the cost of rock and other materials like concrete or sand. Here we assume a rock bed sensible storage unit with

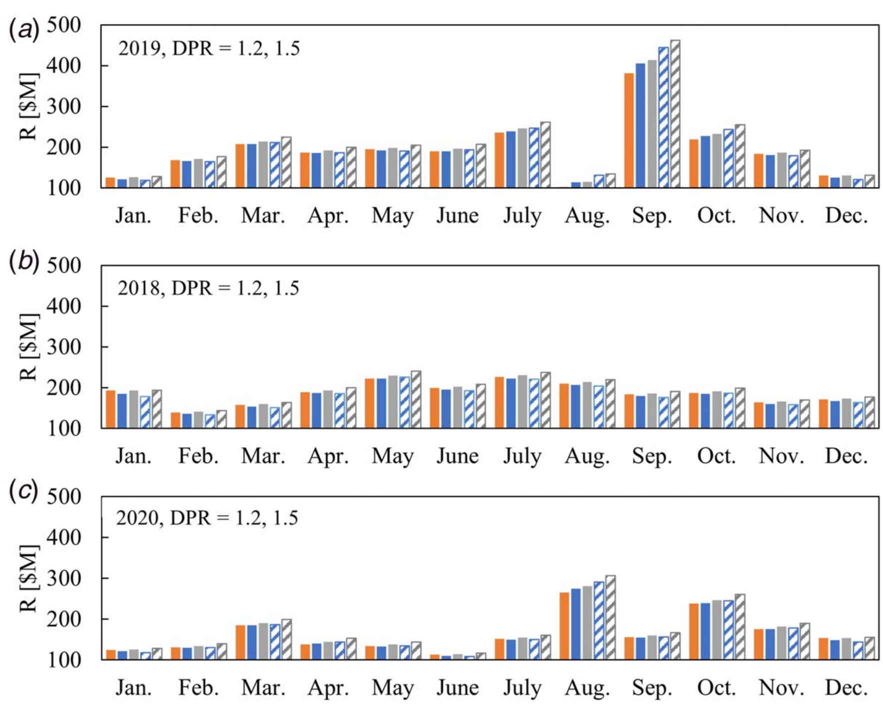


**Fig. 6 The monthly revenue of the conventional nuclear power plant, PCTES, and SCTES in an arbitrage market in the ERCOT grid for 2018–2020 (plots (*a*)–(*c*)) in millions of dollars. Revenue is shown for the conventional plant on the left (orange bar) followed by the PCTES (blue bar) and SCTES (gray bar) for DPR = 1.2. Revenue for DPR = 1.5 is shown in the crosshatched bars with PCTES in blue and for SCTES in gray.**



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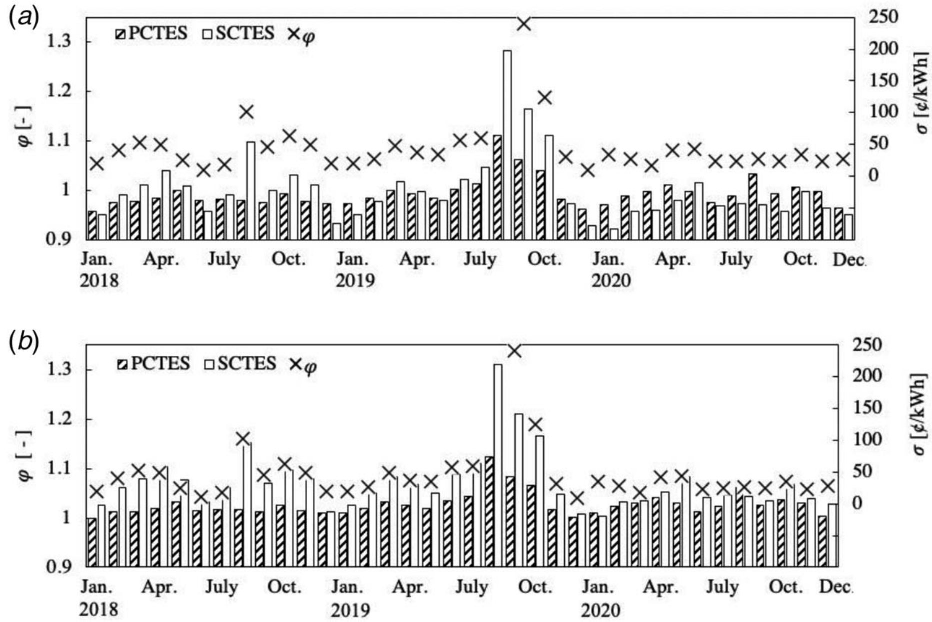


Fig. 7 Monthly revenue for (*a*) PCTES and (*b*) SCTES normalized by the conventional plant revenue (bar chart—left ordinate) and standard deviation of monthly price ("x"—right ordinate) for 2018–2020. The crosshatched bars represent DPR = 1.2. The clear bars represent DPR = 1.5.

a cost of raw materials of $c_{\mathrm{mat}} = \$1.90\,\mathrm{kW\,h_{th}^{-1}}$ [19]. The overhead cost of the rock is assumed to be 10% [32]. In Eq. (5), the storage capacity $Q_{\mathrm{store}}$ is (Table 1)

$$C_{\mathrm{mat}} = 1.1(Q_{\mathrm{store}} c_{\mathrm{mat}}) \tag{5}$$

The cost of the TES container is an estimate based using a steel container insulated with a calcium silicate material [32]. The container is sized based on the volume of rock (assuming a void fraction of 0.365 and 0.02 m particles [19]) required to provide $Q_{\mathrm{store}}$.

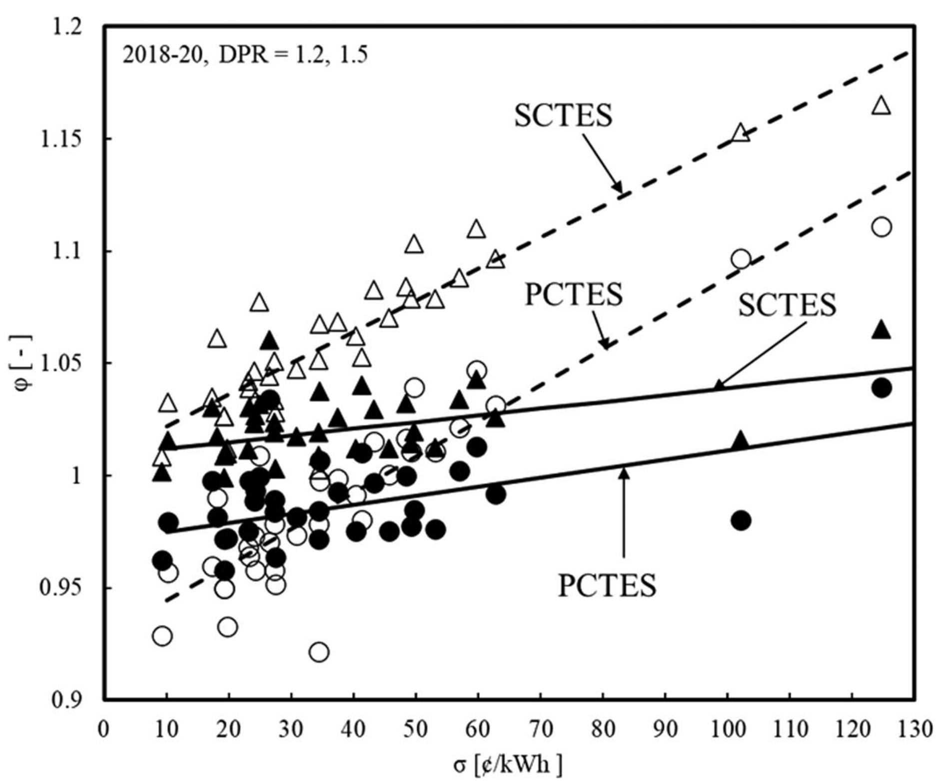


Fig. 8 The monthly relative revenue ($\phi$) as a function of the monthly standard deviation in price. The PCTES is indicated by circles and the SCTES by triangles. Data symbols are solid for DPR = 1.2 and open for DPR = 1.5. Curve fits are overlaid as a visual aid with solid lines for PCTES and dashed lines for SCTES.

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**Table 2 Average annualized pricing and revenue for TES options**

| Year | $P \pm \sigma$ ($\$\,\mathrm{kWh_e^{-1}}$) | Annual relative revenue $\overline{\varphi}$ PCTES | SCTES |
|---|---|---|---|
| *DPR = 1.2* | | | |
| 2018 | 0.244 ± 0.289 | 0.980 | 1.015 |
| 2019 | 0.351 ± 1.207 | 1.012 | 1.042 |
| 2020 | 0.212 ± 0.412 | 0.997 | 1.030 |
| Average | 0.269 ± 0.636 | 0.996 | 1.029 |
| *DPR = 1.5* | | | |
| 2018 | 0.244 ± 0.289 | 0.969 | 1.043 |
| 2019 | 0.351 ± 1.207 | 1.046 | 1.109 |
| 2020 | 0.212 ± 0.412 | 1.010 | 1.078 |
| Average | 0.269 ± 0.636 | 1.010 | 1.077 |

Note: The revenue of the conventional plant is 2.25, 2.32, and 1.97 billion dollars for years 2018–2020, respectively.

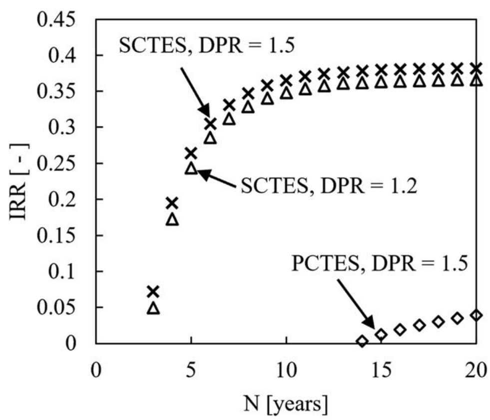


**Fig. 9 IRR versus time span for investment of SCTES for DPR = 1.2 and 1.5 and for PCTES at DPR = 1.5 . There is no IRR for PCTES for DPR = 1.2**

The cost of the power block ($C_{\mathrm{PB}}$) includes the incremental cost of modifications or additions of steam turbines and generator assembly ($c_{\mathrm{ST,G}}$) and other necessary power conversion equipment such as piping, valves, instrumentation and pumps, often referred to as balance of plant ($c_{\mathrm{BOP}}$). The assumed cost of steam turbines is $390\,\$\,\mathrm{kW_e^{-1}}$ [33]. For both the primary and secondary cycles the cost of the turbines is based on the incremental increase of power required (DPR − 1) [33]. Cost of the balance of plant ($c_{\mathrm{BOP}}$) for the SCTES is estimated to be $274\,\$\,\mathrm{kW_e^{-1}}$ [32]; this incremental cost is avoided for PCTES

$$C_{\mathrm{PB}} = (\mathrm{DPR} - 1)(c_{\mathrm{ST,G}} + c_{\mathrm{BOP}}) \tag{6}$$

The operations and maintenance cost ($c_{\mathrm{O\&M}}$) is assumed to be $0.006\,¢\,\mathrm{kWh_e^{-1}}$ for the power conversion equipment and $0.001\,¢\,\mathrm{kWh_e^{-1}}$ for the TES [34,35].

## 3 Results

**3.1 Revenue.** The revenues of the conventional nuclear power plant, the PCTES, and the SCTES are presented by month from 2018 to 2020 in millions of US dollars for DPR values of 1.2 and 1.5 in Figs. 6(*a*)–6(*c*). Figure 7 shows the revenue normalized by the monthly revenue of the conventional plant. The variation by year and month is due to temporal variations in the price of electricity. In the deregulated ERCOT grid, the price reflects the actual supply and demand of electricity. Exceptionally high average prices may be driven by an increase in demand due to external factors such as weather or decreases in supply due to planned or unplanned outages of large power plants.

SCTES consistently provides the highest revenue and revenue increases with increasing DPR as more load is transferred to the higher price periods. The benefit of increased revenue during discharge, when the price for electricity is high, offsets the loss of revenue during charging, when the price for electricity is low. The PCTES does not provide a revenue advantage for most months because the turbines operate a lower efficiency during charging *and* baseload operation. For example, for DPR = 1.2, the efficiency of the conventional plant is 31% whereas the daily efficiency of the PCTES is 29.5% for DPR = 1.2 and 27.9% for DPR = 1.5. Even seemingly small changes in efficiency can decrease revenue, particularly during baseload operation. The SCTES maintains an overall efficiency above 30%.

There is a strong trend of increased revenue for SCTES with increasing variability in price. This trend is illustrated in Fig. 8, which is a plot of the normalized monthly revenue ($\phi$) of the plant with TES versus the standard deviation in the price of electricity. Curve fits are overlaid to better visualize the trends. First consider SCTES. For DPR = 1.2, $\phi$ increases from about 1.01 to 1.04 when the standard deviation in the price increases from 10 to $100\,¢\,\mathrm{kWh_e^{-1}}$. At DPR = 1.5, $\phi$ increases from 1.04 to 1.19 over the same range. The PCTES is not profitable for DPR = 1.2 except in extreme conditions when $\sigma > 100\,¢\,\mathrm{kWh_e^{-1}}$ and $\sigma > 80\,¢\,\mathrm{kWh_e^{-1}}$ for DPR = 1.5.

Table 2 summarizes the normalized revenue for 2018, 2019, and 2020 and averaged over the 3-year period. The revenue of the conventional plant is 2.25, 2.32 and 1.97 billion dollars for 2018, 2019, and 2020, respectively. For DPR = 1.2, the PCTES is slightly revenue negative with a normalized revenue of 0.996. The 3-year averages reinforce the strong performance of SCTES. For DPR = 1.2, normalized revenue is 1.029. For DPR = 1.5, normalized revenue is 1.077.

**3.2 Internal Rate of Return.** The IRR for $1 \leq N \leq 20$ years is plotted in Fig. 9 and Table 3 lists the cost basis for these values and the IRR for 5, 10, and 20 years. IRR is a useful metric to consider the relative merits of different energy investments. The incremental capital cost of the SCTES is about 173 million dollars compared to 101 million dollars for the PCTES for DPR = 1.2. For DPR = 1.5, the incremental capital cost of SCTES is 430 million dollars compared to 254 million dollars for the PCTES. The higher cost of the SCTES is primarily the cost of the secondary power block ($C_{\mathrm{PB}}$). Importantly, the higher EPR of the SCTES justifies the increased capital cost. Even though the PCTES is less expensive to implement, it does not achieve a positive IRR except

**Table 3 Initial capital cost annual O&M and IRR**

| | DPR | $C_{\mathrm{mat}}$ (million dollar) | $C_{\mathrm{con}}$ (million dollar) | $C_{\mathrm{PB}}$ (million dollar) | $C_{\mathrm{TES}}$ (million dollar) | $C_{\mathrm{O\&M}}$ (million dollar) | IRR %, $N$ = 5 years | IRR %, $N$ = 10 years | IRR %, $N$ = 20 years |
|---|---|---|---|---|---|---|---|---|---|
| PCTES | 1.2 | 9.5 | 9.8 | 81.9 | 101.2 | 0.2 | – | – | – |
| | 1.5 | 23.7 | 22.8 | 204.8 | 253.7 | 0.6 | – | – | 3.9 |
| SCTES | 1.2 | 10.0 | 22.2 | 139.4 | 172.6 | 1.4 | 24.3 | 34.8 | 36.6 |
| | 1.5 | 24.8 | 53.7 | 348.6 | 429.7 | 4.0 | 26.4 | 36.5 | 38.2 |

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for DPR = 1.5 and for $N \geq 14$ years. The IRR is 3.9% at $N = 20$ years.

The increased revenue and IRR of the SCTES are due to more efficient performance of the cycle during baseload and charging. The SCTES could realize a 24.3% IRR in 5 years for DPR = 1.2. There is modest increase in IRR to 26.4% for DPR = 1.5. The impact of increasing DPR is modest for all investment periods. For $N = 10$ years, the IRR of the SCTES is 34.8% for DPR = 1.2 and 36.5% for DPR = 1.5. Respective values at $N = 20$ years are 36.6% and 38.2%. The revenue and IRR of the SCTES make this TES configuration an excellent candidate for investment within the price structure of ERCOT and by extension to other arbitrage electricity markets. The revenue stream would increase if the price volatility were to increase.

## 4 Conclusion

Economic aspects of integrating TES with low-carbon nuclear power to provide power flexibility and to improve the profitability of nuclear power in a deregulated US electricity grid have been analyzed. The important effect of changes in capacity factor of the plant due to use of TES, neglected in prior economic analyses of TES with nuclear, prove to impact revenue and IRR. The results show that investing more to ensure the nuclear plant with TES remains highly efficient pays off in terms or revenue generation and IRR in an arbitrage electricity market.

Two approaches to integrate TES with nuclear power were considered. In the PCTES, the TES is integrated fully into the primary cycle. In the SCTES, the TES is discharged to a secondary cycle. The capital cost of the SCTES is 70% higher than the PCTES but the capacity factor, represented by an EPR in Fig. 5, is about 9% higher due to more efficient operation during charging and baseload operation. As a result, the SCTES is a favorable investment opportunity in an arbitrage market, like ERCOT. The benefit of using the SCTES will increase in electricity markets with greater variability in the price of electricity. Using prices for the ERCOT grid from 2018 through 2020, the annual revenue of the SCTES is 3–8% higher than a conventional plant without TES. The IRR is about 35% for a 10-year investment and more than 25% for 5 years. These results justify serious consideration of TES for nuclear even without consideration of the benefits to carbon reduction and management of the grid as more solar and wind come online.

## Conflict of Interest

There are no conflicts of interest.

## Data Availability Statement

The authors attest that all data for this study are included in the paper.

## Nomenclature

$c$ = cost per unit ($\$\,\mathrm{kW\,h_e^{-1}}$)
$d$ = day
$t$ = time (min h)
$y$ = index for year in IRR
$C$ = cost (\$)
$N$ = lifetime of investment (year)
$P$ = price of electricity ($¢\,\mathrm{kW\,h_e^{-1}}$)
$R$ = revenue (\$)
$\dot{W}$ = power (kW)

### Greek Symbols

$\eta$ = first law of efficiency
$\sigma$ = standard deviation in price ($¢\,\mathrm{kW\,h_e^{-1}}$)
$\phi$ = relative revenue
$\chi$ = steam quality

### Subscripts

BL = baseload operation
Ch = charge operation
con = container
conv = conventional plant without TES
$D$ = discharge operation
$f$ = end of time in a mode of operation
O&M = operations and maintenance
PB = power block
RT = round-trip
RT = round-trip efficiency of TES
$s$ = start time of a mode of operation
store = stored energy
STG = steam turbine and generator

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