

# Diurnal Thermal Energy Storage For Cogeneration Applications

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Thermal energy storage can help cogeneration meet the challenges of the 1990s by increasing the flexibility and performance of cogeneration facilities. Thermal energy storage also allows a cogeneration facility to provide dispatchable electric power while providing a constant thermal load.

The first of two studies reported here focused on the relative performance and economic benefits of incorporating a diurnal TES system with a simple-cycle gas turbine cogeneration system to produce dispatchable power during peak- and/or intermediate-demand periods. The results showed that the oil/rock storage system for TES was the most attractive option for the assumed thermal load quality.

The second study evaluated the cost of power produced by a combined-cycle cogeneration plant integrated with thermal energy storage (CC/TES/Cogen). The results indicate relatively poor economic prospects for integrating TES with a combined-cycle cogeneration power plant. However, system design optimization and reductions in storage media costs might improve the economics, perhaps enough to make the CC/TES/Cogen an attractive option for incremental peak power production.

In addition to the economic considerations, environmental factors due to the use of thermal energy storage with conventional cogeneration systems are also reported.

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## INTRODUCTION

The U.S. National Energy Strategy estimates that 200,000 MWe of new electric generating capacity will need to be added between 1993 and 2010. Approximately 40% of the new generating capacity will be for peak or intermediate loads with the remaining 60% providing continuous baseload power generation. Gas turbine schemes such as simple-cycle cogeneration, combined-cycle power plants, and integrated-gasification combined-cycle power plants are becoming the generation options of choice because of their relatively low capital cost, flexibility, reduced environmental impact, and higher thermal efficiency. Thermal energy storage (TES) for utility applications includes a range of thermal energy storage technologies that can further improve the efficiency, flexibility and economics of natural-gas-fired gas turbine options. This is achieved by decoupling power generation from the production of process heat, allowing the production of dispatchable power while fully using the thermal energy available from the gas turbine. The thermal energy from the turbine exhaust can be stored either as sensible heat or as latent heat and used during peak demand periods to produce electric power or process steam/hot water. However, the additional materials and equipment necessary for a TES system will add to the capital costs. Therefore, the economic benefits of adding TES to a conventional cogeneration system would have to outweigh the increased costs of the combined system.

The Pacific Northwest Laboratory (PNL) leads the U.S. Department of Energy's Thermal Energy Storage Program. The program focuses on developing TES for daily cycling (diurnal storage), annual cycling (seasonal storage), and utility applications [utility thermal energy storage (UTES)].

Several of these technologies can be used in a cogeneration facility. This article discusses the relative performance and economic benefits of incorporating a diurnal TES system with (1) a simple-cycle, and (2) a combined-cycle gas turbine cogeneration system. The relative benefits of combining a TES system with a cogeneration system were determined by comparing the levelized energy costs of the combined system (for supplying the same preselected steam load) with that of a conventional cogeneration system and a base case electric plant. For example, the combined-cycle study evaluated the cost of power produced by a combined-cycle electric power plant (CC), a combined-cycle

cogeneration plant (CC/Cogen), and a combined-cycle cogeneration plant integrated with thermal energy storage (CC/TES/Cogen) systems designed to serve a fixed process steam load. The value of producing electricity was set at the levelized cost for a CC plant, while that of the process steam was for a conventional stand-alone boiler.

## DIURNAL THERMAL ENERGY STORAGE

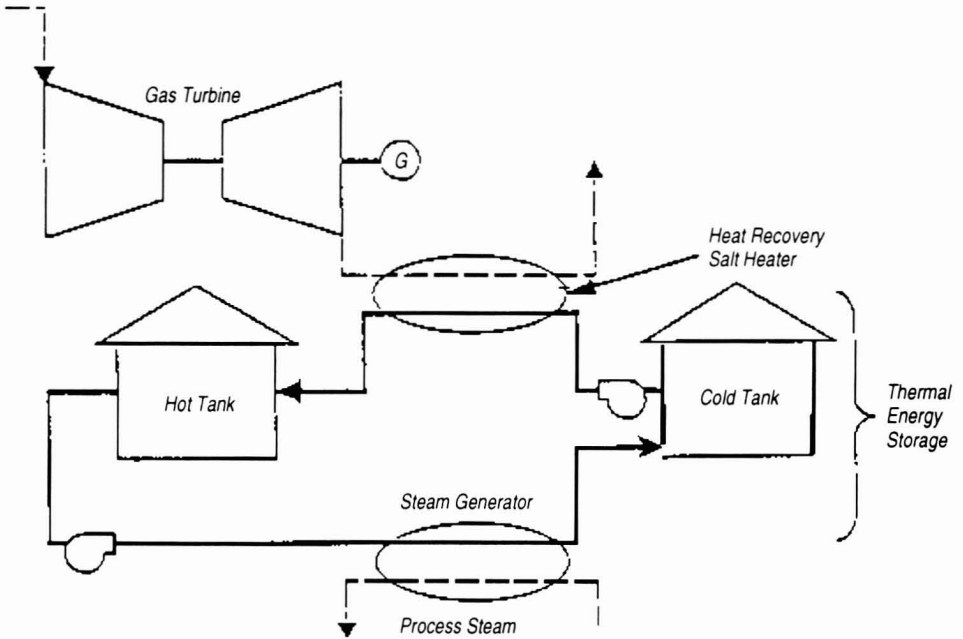
A number of emerging issues may limit the number of useful applications of cogeneration. One of these is a mismatch between the demand for electricity and thermal energy on a daily basis. Increasingly, utilities are requiring cogenerators to provide dispatchable power, while most industrial thermal loads are relatively constant during a 24-hour period. Diurnal TES can decouple the generation of electricity from the production of thermal energy, allowing the cogeneration facility to supply dispatchable power. Diurnal TES stores thermal energy recovered from the exhaust of the prime mover (gas turbine) to meet daily variations in the demand for electric power and thermal loads.

### Concept

The concept for integrating TES in a natural-gas-fired (simple-cycle) cogeneration facility is shown in Figure 1. The facility consists of 1) a gas-turbine prime mover, 2) a heat recovery salt heater, 3) a thermal energy storage system, and 4) a salt-heated steam generator. The gas turbine is operated during peak demand time periods and the exhaust heat is used to heat molten salt in a heat recovery salt heater. Cold salt at 288°C (550°F) is pumped from the cold salt tank, through the heat recovery salt heater, where it is heated to about 510°C (950°F) before being pumped to the hot salt storage tank. Hot salt is continuously removed from the hot salt tank and used as a heat source to meet the constant thermal load. A cogeneration plant with a TES system sized for an 8-hr peak demand period would provide a 30-MWe peaking capacity compared to a similar conventional cogeneration facility that would provide a 10-MWe base-load capacity.

### TES System Description

Depending on the characteristics of the thermal load, a variety of



**Figure 1. Schematic of a Simple-cycle Cogeneration Plant with Thermal Energy Storage (SC/TES/Cogen)**

thermal storage systems can be used. Options for thermal storage include:

- “60/40” Salt TES—The “60/40” salt is an excellent thermal energy storage medium for high-temperature TES applications, using a mixture of sodium nitrate (60 wt%) and potassium nitrate (40 wt%) that can operate at temperatures up to 566°C (1050°F). However, the mixture freezes at 240°C (464°F). To help prevent freezing, these salt systems are usually operated at temperatures above approximately 288°C (550°F). The minimum operating temperature limits the amount of waste heat that can be recovered from a combustion turbine’s exhaust because the exhaust can only be cooled to approximately 315°C (600°F). Typically, this type of TES system uses separate hot and cold salt tanks. A more complete discussion of the “60/40” salt TES is presented in Drost et al. (1989).

- **Oil/Rock TES**—Oil/rock TES is an attractive alternative for intermediate-temperature applications. Low-cost heat transfer oils such as Caloria HT-43<sup>b</sup> can operate at up to 304°C (580°F). The TES system consists of a single large tank filled with a mixture of oil and a low-cost filler, such as river rock. The tank is operated to maintain hot oil at the top of the tank and cold oil at the bottom. This arrangement stratifies the fluid in the tank resulting in minimal mixing between the tank’s hot and cold regions. During normal operation, cold oil is removed from the bottom of the tank, heated in the heat recovery oil heater, and returned to the top of the tank. Thermal energy is stored in the mixture of oil and rock. Oil/rock TES is less expensive than molten salt TES, but it is limited to low-temperature applications (< 300°C). Oil/rock TES is described in more detail in Drost et al. (1990).
- **Combined Molten Salt and Oil/Rock TES**—The advantages of both storage concepts above can be retained by using a combination of molten salt TES for high-temperature and an oil/rock TES for lower-temperature thermal energy storage. This allows the combustion turbine exhaust to be cooled to near ambient conditions, while maintaining higher availability than is possible with oil/rock TES alone.
- **Hitec<sup>c</sup> Salt TES**—Hitec salt is another molten salt that operates between 454°C and 177°C (850°F and 350°F). It is a mixture of sodium nitrate (7 wt%), potassium nitrate (53 wt%) and sodium nitrite (40 wt%). Hitec salt would allow greater heat recovery from turbine exhaust than the “60/40” salt, but would not be as useful as the “60/40” salt at higher temperatures (> 450°C—as in combined-cycle power production applications). In addition, the Hitec salt is a little more expensive than the “60/40” salt.

Selection of the storage medium will depend on characteristics of the thermal load. If high-temperature thermal energy is required to meet the thermal load, a choice of the “60/40” salt TES, Hitec salt TES, or a combined “60/40” salt and oil/rock TES can be used. Alternatively, if the thermal load uses thermal energy at a temperature below 288°C (550°F), oil/rock TES may be the preferred option.

<sup>b</sup>Trademark of the Exxon Corporation, Houston, Texas.

<sup>c</sup>Trademark of the Dupont Corporation, Wilmington, Delaware.

## **Benefits**

The use of high-temperature TES in cogeneration applications has the following benefits:

- High-temperature TES will allow a natural-gas-fired cogeneration facility to produce dispatchable power while meeting constant thermal loads.
- High-temperature TES integrated in a natural-gas-fired cogeneration facility allows all power generation to occur during periods of peak demand; the installed capacity of the prime mover will be substantially larger than for a conventional cogeneration facility. A cogeneration plant with a TES system sized for an 8-hr peak demand period would provide 30 MWe of peaking capacity compared to a similar conventional cogeneration facility that would provide 10 MWe of base-load capacity.
- All natural gas is used to fire the combustion turbine (compared to direct natural gas firing of the waste heat steam generator). This results in high-efficiency operation by ensuring that all natural gas is used to produce both electric power and thermal energy.

## **Technical Status**

The "60/40" salt TES has been extensively investigated for solar thermal power generation applications. Investigations have included bench-scale testing, detailed design studies, and field demonstrations. Based on the results of these investigations, the Department of Energy and a group of electric utilities are sufficiently confident of the technical feasibility of the concept to embark on the \$40 million Solar II demonstration of molten salt central receiver technology. This suggests that the "60/40" salt TES is technically ready for a large-scale cogeneration demonstration. Oil/rock storage has been successfully demonstrated for solar thermal applications and is commercially available. Hitec salt has been used in several industries. Alternative salts (ternary mixtures) that can operate between 566°C and 121°C (1050°F and 250°F) have been identified, but additional research is necessary before large-scale demonstration is justified. Successful development of a TES system using these alternative salts could avoid the need for a

combined molten salt and oil/rock TES system to cover the entire temperature range.

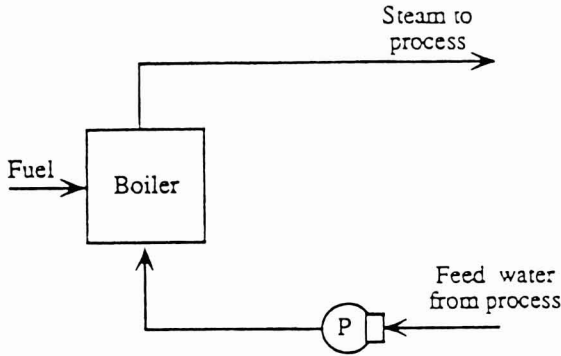
### **System Descriptions**

Design and performance characteristics were developed for the following six types of steam and/or electric power plants: 1) a boiler plant (boiler), as shown in Figure 2; 2) a simple-cycle electric power plant with steam cogeneration (SC/Cogen) as shown in Figure 3, 3) a simple cycle electric power plant with steam cogeneration and thermal energy storage (SC/TES/Cogen) (Figure 1); 4) a combined-cycle electric power plant (CC) (Figure 4); 5) a combined-cycle electric power plant with steam cogeneration (CC/Cogen) (Figure 5); and 6) a combined-cycle electric power plant with steam cogeneration and thermal energy storage (CC/TES/Cogen) (Figure 6).

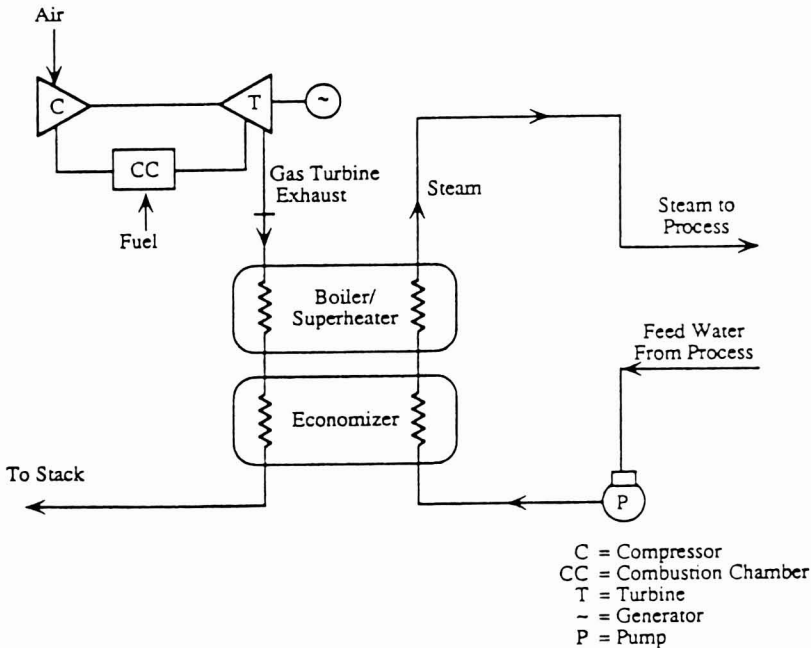
The first, second, and fourth plants were evaluated to provide a reference for comparing the cost of steam and electricity from the SC/TES/Cogen plant, while the first, fourth, and fifth plant concepts were evaluated to provide a reference for the CC/TES/Cogen plant. The boiler plant was evaluated to define the reference cost of producing steam, hence the value of steam produced by the cogeneration plants. Similarly, the CC plant was evaluated to define the reference cost of producing electricity, hence the value of electricity produced by the cogeneration plants. Many factors affect the value of products such as steam and electricity. This approach is consistent with defining value as equal to the marginal cost of production from the likely alternative source. While a conventional boiler plant was an obvious reference technology for producing steam, many different options are available for producing electricity. A CC power plant provides a convenient benchmark for comparison with CC/Cogen and CC/TES/Cogen because the latter two plants are based on modifications to the basic CC power plant technology.

### **PLANT ARRANGEMENTS**

The base-case system is a conventional boiler plant (for setting the steam cost) and a combined-cycle power plant (for setting the electricity cost) against which a simple and a combined-cycle cogeneration system (with a gas-turbine prime mover and/or a steam turbine with a heat recovery steam generator [HRSG]) were compared.



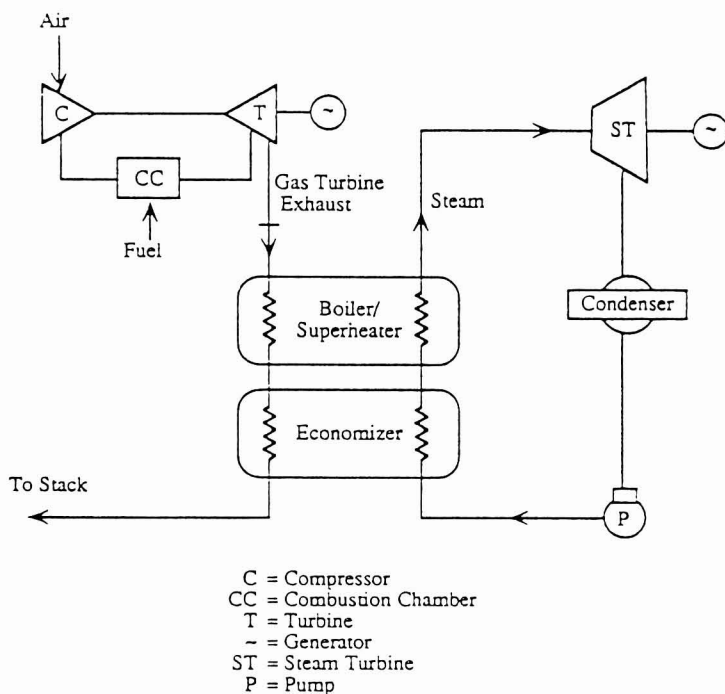
**Figure 2. Schematic of a Boiler Plant**



**Figure 3. Schematic of a Simple-cycle Cogeneration Plant (SC/Cogen)**

**Conventional SC/Cogen Plant**

The conventional simple-cycle cogeneration plant (Figure 3) consists of a gas turbine (GT) that is fired by a natural gas combustor. In addition to producing power through the generator, the turbine ex-

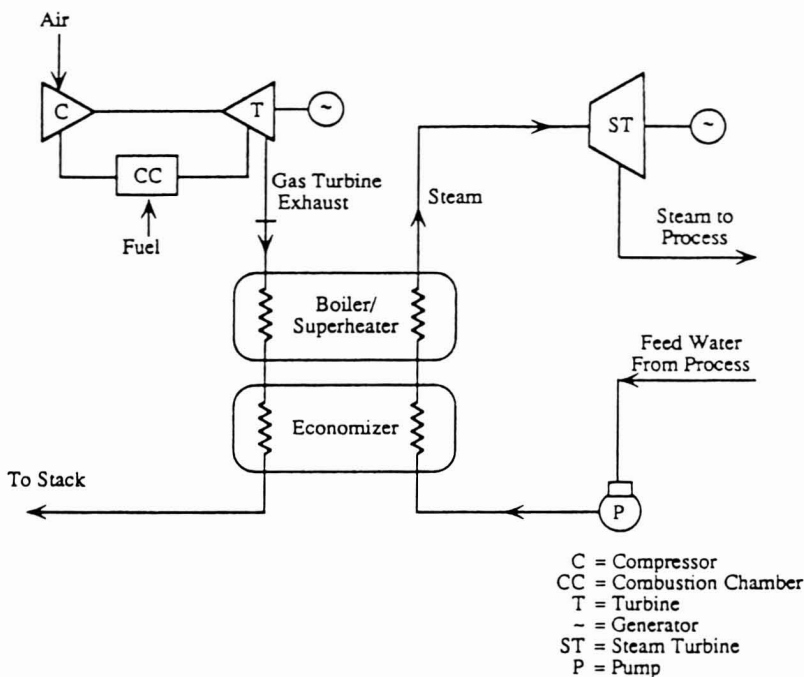


**Figure 4. Schematic of a Combined-cycle Electric Power Plant (CC)**

haust at  $538^{\circ}\text{C}$  ( $1000^{\circ}\text{F}$ ) is used in a heat recovery steam generator (HRSG) to produce the process steam load. The net efficiency of the gas turbine is assumed to be 31% (a heat rate of 11,000 Btu/kWh) for larger gas turbines ( $> 100$  MWe rating) and 29.6% (a heat rate of 11,500 Btu/kWh) for smaller turbines ( $< 100$  MWe rating).

### SC/Cogen Plant with TES for Peaking

An oil/rock or salt TES system interposed between the gas turbine and the steam generator in a conventional simple-cycle cogeneration plant can provide a cycling capability (Figure 1). Instead of generating steam directly, the heat from the gas turbine exhaust is used to heat the oil or molten salt, which is then stored in a tank until further use. The gas turbine is operated whenever peaking power capacity is needed by the utility. The TES serves to decouple the steam generator and the gas turbine from the rest of the plant, allowing process steam

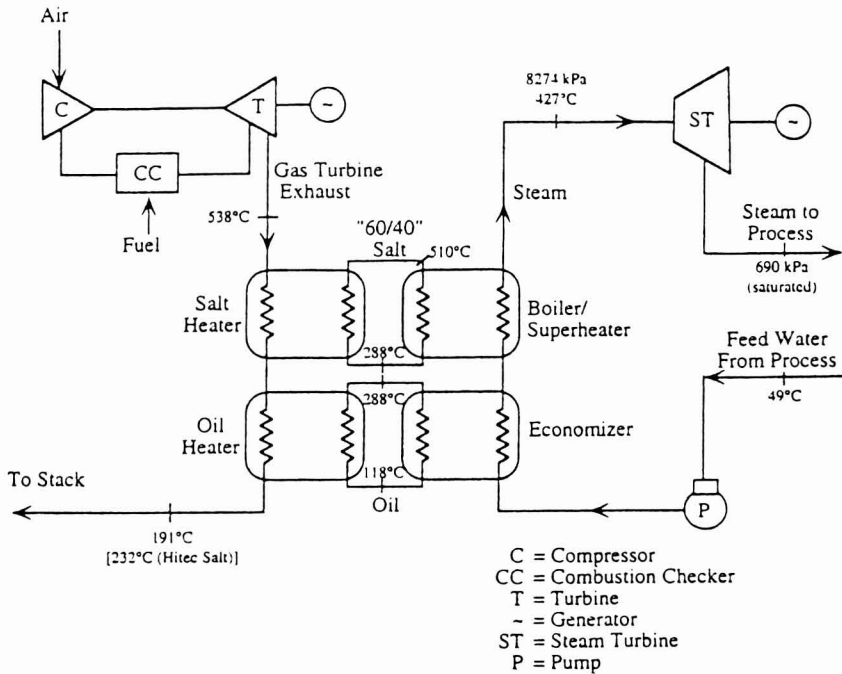


**Figure 5. Schematic of a Combined-cycle Cogeneration Plant (CC/Cogen)**

production for a steam turbine or other process thermal loads to continue for the entire day. In the case of the heat recovery salt heater, it may be possible to use direct-contact heat exchange between the exhaust gas and the salt. If feasible, this direct-contact heat exchange process would dramatically reduce the cost of the heat recovery salt heater and would improve the overall plant performance. There was no attempt made to optimize the sizes and costs of the components of the different systems evaluated in this study. Otherwise, more advantageous versions of each TES/cogeneration system or other system configurations with molten salt storage could have been designed and analyzed.

### Conventional CC/Cogen Plant

One of the primary goals of this study was to develop concept arrangements that minimize the impact of including TES on the design and the layout of a cogeneration plant. Therefore, there is sub-



**Figure 6. Schematic of a Combined-cycle Cogeneration Plant with Thermal Energy Storage (CC/TES/Cogen)**

stantial similarity between a conventional combined-cycle cogeneration plant (CC/Cogen) and the combined-cycle cogeneration with TES design (CC/TES/Cogen). The conventional combined-cycle cogeneration plant (Figure 5) consists of a prime mover (a gas turbine, in this case) that is fired by a natural gas combustor. The turbine exhaust at 538°C (1000°F) is used in a HRSG to produce steam loads of a power-producing steam turbine, which, in turn, exhausts to provide the process steam load. Therefore, the electrical capacity of this plant is greater than that of the simple-cycle cogeneration plant.

### CC/Cogen Plant with TES for Peaking

An oil/rock or salt TES system interposed between the gas turbine and the steam generator in a conventional combined-cycle cogeneration plant can provide a cycling capability (Figure 6) similar to the case of the simple-cycle cogeneration plant combined with thermal energy storage discussed earlier.

## System Steam Requirements

Process steam requirements are summarized in Table 1. Several systems were evaluated for meeting the same process steam load. In some cases, the systems are the same as one of six plant types described above, while others are combinations of two or more of the plant types. The gas turbine rating depends on the length of time during the day that the gas turbine is operated with intermediate- and/or peak-load electricity being sold to the utility. For example, having assumed the system will supply a constant 24-hr steam load, the rating is twice the base-load size if it were operating only for 12 hrs in a day. The waste heat recovery is in the form of heated oil or salt that is then stored in the oil/rock or salt storage tank to supply the 24-hr steam load. The additional system analyzed was the 8-hr operation of an oversized (threefold) gas turbine for selling peak power to the local utility. The alternative systems evaluated were 1) a boiler operating 24 hrs/day, 2) a SC/Cogen or a CC/Cogen plant operating 24 hrs/day, 3) a SC/Cogen or a CC/Cogen plant operating 8 hrs/day and selling peak-load power to the utility and a boiler operating for the remaining 16 hrs/day to supply the steam load, 4) a SC/Cogen or a CC/Cogen plant operating 12 hrs/day to sell intermediate-load power to the utility and a boiler operating 12 hrs/day, and 5) a SC/TES/Cogen plant using one of three TES systems discussed above or a CC/TES/Cogen plant using "60/40" salt and oil/rock storage or Hitec salt storage. The last alternative was evaluated with the gas turbine operating either 8 or 12 hrs/day and the steam turbine (in the CC/TES/Cogen plant) operating 24 hrs/day for both types of storage systems.

**Table 1. Process Steam Requirements**

Flow Rate:	181,440 kg/hr (400,000 lb/hr); 24 hrs/day; 320 days/year
Supply Conditions:	690 kPa (100 psia); saturated steam with a quality of 0.973
Condensate Return	
Conditions:	49°C (120°F) (saturated liquid)

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## System Sizing

Rudimentary design specifications were developed for each major system component to define the cost and performance basis. In general, equipment was sized to meet the steam requirements stated in Table 1. Key design and performance assumptions are presented in Table 2.

**Table 2. Design and Performance Assumptions**

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### Natural Gas-Fired Systems

#### Steam Turbine Inlet Conditions:

- 181,440 kg/hr (400,000 lb/hr)
- 8274 kPa (1200 psia)
- 427 °C (800°F)

#### Steam Turbine Power Calculations

- turbine efficiency = 0.90
- generator efficiency = 0.98
- parasitic power = 0.02

#### Gas Turbine Heat Rate

- 11,500 Btu/kWh for GT sizes < 100 MWe
- 11,000 Btu/kWh for GT sizes > 100 MWe

#### Gas Turbine Exhaust Temperature = 538°C (1000°F)

#### Overall Heat Transfer Coefficients

- 150 W/m<sup>2</sup> °C (26.6 Btu/hr ft<sup>2</sup> F) for HRSG and storage media heaters
- 846 W/m<sup>2</sup> °C (150 Btu/hr ft<sup>2</sup> F) for storage media steam generators

#### Storage Media Cycle Temperatures

- "60/40" salt: 288°C to 510°C (550 to 950°F)
  - Oil/rock: 118°C to 288°C (250 to 550°F)
  - Hitec salt: 218°C to 454°C (425 to 850°F)
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### *Steam Generator Sizing*

Steam generators include conventional gas turbine heat recovery steam generators and steam-generation equipment from thermal storage media. Process steam condensate and steam turbine inlet conditions define the economizer, boiler, and superheater heat duties and water/steam inlet and exit temperatures. Unit size depended on both the gas turbine exhaust temperature and the ultimate reject temperature after heat recovery. In general, lowering the reject temperature increases the waste heat recovery fraction and reduces the size of the gas turbine required, but results in larger, more costly heat exchangers. The minimum reject temperature is limited by the boiler pinch point. A reasonable ultimate reject temperature was selected from several investigated, but a formal optimization was not conducted.

The first step for sizing storage media heated steam generators was to select the media operating temperature range from within the upper and lower temperature limits. In general, the temperature range should be as large as possible to minimize storage costs. A higher upper temperature will reduce steam generator costs but increase media heater costs. Boiler pinch point limitations must also be considered in setting the lower media temperature. Thus, the operating temperature range affects all TES charging and discharging equipment, as well as the TES unit. Again, the design approach was to select reasonable, but not necessarily optimal temperature ranges; the specific temperature range for each media type was shown in Table 2. Once the media temperature range was established, the design procedure was the same as that described for the HRSG.

### *Storage Sizing*

Thermal storage capacity (MWht) is independent of the media type because the same total energy must be transferred in the steam generator, and the storage efficiency is essentially the same. Thermal losses for large (500 to 2,500 MWht) storage systems such as those required for the systems evaluated in this study are less than 1% (Williams et al. 1987). An overall efficiency of 97%, which allows for losses in piping and the thermal equivalent of pumping parasitics, was presumed. The required storage capacity is directly proportional to the steam generation energy and the number of hours the steam generator is operated from storage (or 24 minus the number of hours the gas turbine operates).

### *Storage Media Heater Sizing*

Media heater thermal duties and media temperatures were established as part of the media heated steam generator sizing process. Design considerations and procedures were similar to those described above for the HRSG sizing. In general, the minimum gas turbine exhaust reject temperature is limited by the minimum media temperature. For the nitrate salt and oil/rock storage system, consideration must also be given to the pinch point at the low-temperature end of the salt heater and high-temperature end of the oil heater.

### *Gas Turbine Sizing*

The required gas turbine generating capacity depends on its heat rate and the exhaust temperature (after thermal recovery in the HRSG or media heater). Heat rates are normally quoted in Btu/kWh. For example, gas turbines with a generating capacity greater than 100 MWe were assumed to have a heat rate of 11,000 Btu/kWh in this study. If inputs and outputs are both expressed in kWh, the equivalent heat rate is 3.223, i.e., 3.223 kWh of fuel energy are converted into 1.000 kWh of electricity and 2.223 kWh of exhaust heat. In this study, all exhaust heat was assumed to leave the turbine in the form of the exhaust gas at a temperature of 538 °C (1000 °F). Thus, the ratio of electric energy to exhaust energy is 1/2.223 or more generally, 1/(HR-1), where “HR” is the heat rate in kWh of fuel energy per kWh of electricity. Recoverable energy in the exhaust is measured relative to 25°C (77°F), the reference temperature for measuring the energy input from the gas fuel. Therefore, the heat recovery fraction becomes (1000-TR)/(1000-77), where “TR” equals the ultimate reject temperature after heat recovery. The waste heat recovery fraction can be combined with the electric/exhaust energy ratio to produce Equation (1) defining the relationship between gas turbine generating capacity and the waste heat recovery rate. The maximum capacity of an individual gas turbine unit was limited to 150 MWe, resulting in either two or three parallel gas turbine and heat recovery trains.

$$kWe = kWt * 923/[(HR - 1) * (1000 - TR)] \quad (1)$$

### *Equipment Sizes*

Gas turbine, steam turbine, media heater, storage, and steam generator equipment sizes are summarized in Table 3.

Table 3. System Equipment Sizes

Systems	Size/Rating
Boiler	181,440kg/hr (400,000 lb/hr) steam.
Simple-Cycle Cogeneration (SC/Cogen)	
Gas Turbine, MWe	89
Heat Recovery Steam Generator (HRSG), m <sup>2</sup>	4627
Combined-Cycle (CC)	
Gas Turbine, MWe	94
HRSG, m <sup>2</sup>	
Economizer	5846
Boiler	6143
Superheater	1041
Steam Turbine, MWe	50.0 (condensing)
Combined-Cycle Cogeneration (CC/Cogen)	
Gas Turbine, MWe	94
HRSG, m <sup>2</sup>	
Economizer	5846
Boiler	6 143
Superheater	1041
Steam Turbine, MWe	50.0 (condensing)
	Size/Rating

	<u>Oil/Rock</u>		<u>"60/40" Salt</u>		<u>Hitec Salt</u>	
	12 hr GT Operation	8 hr GT Operation	12 hr GT Operation	8 hr GT Operation	12 hr GT	8 hr GT
Simple-Cycle Co-generation with TES (SC/TES/Cogen)						
Gas Turbine, MWe	2 × 97	3 × 97	2 × 138	3 × 138	2 × 97	3 × 97
Media Heater, m <sup>2</sup>	13012	20772	102048	153066	36547	54818
Storage, MWht	1874	2500	1953	2604	1562	2083
Steam Generator, m <sup>2</sup>	3234	3234	649	649	1103	1103
			Hitec Salt			
Simple-Cycle Co-generation with TES (SC/TES/Cogen)						
Gas Turbine, MWe	2 × 103.5	3 × 103.3	2 × 117.5	3 × 117.3	2 × 117.5	3 × 117.3
Steam Turbine, MWe	24.4	24.4	24.4	24.4	24.4	24.4
Media Heater, m <sup>2</sup>	2 × 9201	3 × 9201				
Oil/Rock	2 × 32528	3 × 32528				
"60/40" salt						
Hitec salt						
Storage, MWht	597	795	2 × 26580	3 × 26580		
Oil/rock	1233	1644				
"60/40" salt						
Hitec salt			1830	2440		
Steam Generator, m <sup>2</sup>	2379	2379				
Economizer	1840	1840	1236	1236		
Boiler	223	223	1989	1989		
Superheater			428	428		

## ECONOMIC EVALUATION

The economic evaluation was conducted by calculating and comparing the levelized cost of steam produced by the alternative concepts being considered. Levelized cost analysis combines initial cost, annually recurring cost, and system performance characteristics with financial parameters to produce a single figure-of-merit (the levelized cost) that is economically correct and can be used to compare the projected steam costs of alternative boiler and cogeneration plant concepts. The specific methodology used was that defined in Brown et al. (1987).

Specific financial assumptions used to calculate the levelized steam cost are listed in Table 4. These assumptions are intended to be representative of industrial ownership. Brown et al. (1987) was the reference for the discount rate, general inflation rate, property tax and insurance rate, and combined state and federal income tax rate. The economic life was set at 30 years based on standards prescribed by the Electric Power Research Institute (EPRI) (1989) for facilities similar to the boiler and cogeneration plants considered in the current study. The corresponding depreciable life is 20 years (Van Knapp et al. 1989). The first year of operation was set at 1995 because the storage systems considered in the current study are mature and could be implemented immediately. The price year was set to mid-1990 for convenience. The system construction period, set at 2 years, was also based on data presented in EPRI (1989) for similar systems. Capital and nonfuel operation and maintenance (O&M) costs were assumed to escalate at the same rate as general inflation. Natural gas was assumed to escalate at 3.8% in excess of general inflation (i.e., at 7%/year overall) based on fuel price projections prepared by the Energy Information Administration (1991).

In general, a levelized cost analysis determines the revenue required to exactly cover all costs associated with owning and operating a facility, including return on investment. Typically, the required revenue is expressed per unit of production, e.g., \$/kWh or \$/klb steam. For cogeneration systems, there are two revenue producing products, electricity and steam. Increasing the revenue associated with electricity decreases the revenue required from steam and vice-versa. For the simple-cycle cogeneration analysis, the reference cost of steam was established on the basis of the boiler plant, and for the combined-cycle analysis, either the electric or steam revenue rate was assumed for

**Table 4. Financial Assumptions**

<u>Description</u>	<u>Assumption</u>
System economic life	30 years
System depreciable life	20 years
Nominal discount rate	9.3%/year
General inflation rate	3.1 %/year
Capital inflation rate	3.1 %/year
O&M inflation rate	3.1 %/year
Natural gas inflation rate	7.0%/year
Combined state and federal income tax rate	39.1%
Property tax and insurance rate	2.0%
System construction period	2 years
Price year	1990
First year of system operation	1995

each cogeneration case and the levelized cost analysis solved for the required revenue rate for the other product. The value of cogenerated steam and electricity was established based on the cost of steam from a stand-alone boiler plant and the cost of electricity from a combined-cycle plant. Capital cost and operation and maintenance cost estimates were based on models developed for the steam and cogeneration plant components (Somasundaram et al. 1992).

## RESULTS AND DISCUSSION

The break-even electric rates for the simple-cycle cogeneration analysis at which the levelized steam cost is the same as that of a boiler plant (\$9.03/klb) are given in Table 5. The break-even rate for the conventional cogeneration system is \$0.035/kWh, while that for the cogeneration system with TES varies depending on the storage medium and the power production schedule. The corresponding rate for a gas turbine plant is given for comparison purposes. It can be seen that the oil/rock TES system can provide on-peak power at a cost of \$0.045/kWh to \$0.050/kWh, which is considerably less expensive than the simple gas turbine case (or the CC plant as shown in Table 6).

**Table 5. Breakeven Electric Rates for Boiler Steam Costs (Levelized)**

System Configuration	Breakeven Electric Rates (\$/kWh)	
Simple-Cycle Gas Turbine (SC)	0.08	
Simple-Cycle Cogeneration (SC/Cogen) (24-hr GT operation)	0.035	
Simple-Cycle Cogeneration with TES (SC/TES/Cogen)		
	<u>12-hr GT operation</u>	<u>8-hr GT operation</u>
Oil/Rock	0.045	0.050
"60/40" Salt	0.079	0.095
Hitec Salt	0.059	0.070

**Table 6. Reference Steam and Electricity Costs/Values**

	Daily Operating Period		
	<u>8 hrs</u>	<u>12 hrs</u>	<u>24 hrs</u>
Boiler LEC, \$/klb	11.23	10.01	8.71
CC Plant LEC, \$/kWh	0.072	0.064	0.055

The molten salt cases are less attractive for the assumed process load conditions. The Hitec salt can provide peak power at a slightly less expensive rate than the "60/40" salt, primarily because of the wider temperature range of the storage medium. In general, lower-temperature storage reduces the size and cost of the storage media heater, while higher-temperature storage reduces the size and cost of the media-heated steam generator. Poor heat transfer in the media heater (on the exhaust gas side) puts a premium on the lower approach temperatures required of high-temperature storage systems. Thus, the oil/rock system has a heat exchanger sizing and cost advantage over the two salt systems. The oil/rock system is also the least expensive (on a \$/MWh basis) when each storage system is allowed to cycle through its maximum temperature range. It should also be noted that the

systems evaluated have not been optimized; more advantageous versions of each TES/cogeneration system could be identified by considering other combinations of storage media temperature range and heat exchanger approach temperatures. Varying these design factors trades off heat exchanger and storage system costs. Also, future research and development efforts focused on the salt storage media may further reduce the costs of such storage media and make them more attractive for wider range of temperature conditions.

For the case of combined-cycle cogeneration, the levelized costs of steam production from a boiler plant, and that of electricity production from a CC plant were calculated to establish the reference cost/value of these two commodities when produced by a cogeneration plant (Somasundaram et al. 1993). The levelized energy costs (LECs) for these two systems are shown in Table 6 for different daily operating periods. As would be expected, the LECs decline with increased daily operating hours as the fixed capital and O&M costs are spread over a larger annual energy output.

The LECs from a CC/Cogen plant were also calculated to establish a reference for measuring the impact of adding TES. Again, for any multiple energy product operation, the value of all but one energy product must be fixed to solve for the LEC of the remaining product. Thus, the LECs of steam and electricity from a CC/Cogen plant were calculated by alternately fixing the value of steam or electricity at the levels indicated in Table 6. Table 7 presents steam LECs for alternative systems producing identical rates of steam flow 24 hrs/day, with electric power being produced at different schedules and amounts. The results indicate that a CC/Cogen plant operating 24 hrs/day would produce steam at the lowest possible cost. In addition, a CC/Cogen/

**Table 7. Levelized Cost of Baseload Steam**

<u>System Description</u>	<u>Levelized Energy Cost, \$/klb</u>
24 hr boiler	8.71
24 hr CC/Cogen	2.90
12 hr CC/Cogen and 12 hr boiler	6.73
8 hr CC/Cogen and 16 hr boiler	7.62
12 hr CC/Hitec Salt TES/Cogen	8.46
8 hr CC/Hitec Salt TES/Cogen	10.77

boiler hybrid system would produce steam at a lower average cost than a stand-alone boiler, as long as the CC/Cogen part of the system is operated for at least 8 hrs/day. (Note: At some daily operating period of less than 8 hrs, a stand-alone boiler would be preferred, but this break point was not determined)

Table 8 presents electricity LECs for alternative systems producing power 8 or 12 hrs/day at different rates with steam being produced at identical rates 24 hrs/day. Finally, Table 9 shows the marginal cost of electric power provided by the CC/Hitec Salt TES/Cogen system relative to the reference CC/Cogen system. The results shown in these two tables further emphasize that the CC/Cogen system is the preferred option to the CC/TES/Cogen systems. In fact, the marginal cost of power from the CC/Hitec Salt TES/Cogen system is significantly higher than the cost of power produced by a CC plant alone.

**Table 8. Levelized Cost of Peaking Power**

<u>System Description</u>	<u>Levelized Energy Cost, \$/kWh</u>	
	<u>8-hr peak</u>	<u>12-hr peak</u>
CC	0.072	0.064
CC/Cogen	0.061	0.050
CC/Hitec Salt TES/Cogen	0.079	0.063

**Table 9. Marginal Cost of Peaking Power**

<u>System Description</u>	<u>Levelized Energy Cost, \$/kWh</u>	
	<u>8-hr peak</u>	<u>12-hr peak</u>
CC/Hitec Salt TES/Cogen	0.105	0.099

## ENVIRONMENTAL CONSIDERATIONS

Atmospheric emissions for cogeneration plants result from the combustion of fuel in the gas turbine. The principal concern for natural-gas-fired turbines is nitrogen oxides (NO<sub>x</sub>), although other components (carbon monoxide (CO) and total solid particulates (TSP)) are also emitted, albeit in relatively minor amounts. Actual emissions will depend on the design of the turbine and the operating conditions. The

emissions reported here for cogeneration systems are based on data presented in Esposito (1989) for a General Electric Model PG-7 111EA turbine used in a combined-cycle application. Reference operating conditions and emission rates are presented in Table 10.

**Table 10. Gas Turbine Emission Assumptions**

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Turbine Type: General Electric Model PG-7111EA
Ambient Temperature: 15°C (59°F)
Ambient Humidity: 60% relative humidity
Site Elevation: sea level
NO <sub>x</sub> emission concentration: 42 ppmv
NO <sub>x</sub> control method: steam injection
Fuel: natural gas
NO <sub>x</sub> emission rate = 0.535 kg/MMBtu
CO emission rate = 0.036 kg/MMBtu
TSP emission rate = 0.018 kg/MMBtu

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Emissions data for six different cogeneration systems considered here are presented in Table 11. Fuel consumption, steam production, and electricity production numbers for each of these systems is presented in Table 12 to help explain the emissions results. Total emissions are directly proportional to annual fuel consumption, which varies depending on the design of each cogeneration system. The combined-cycle (CC) systems consume more fuel, but produce more power than the simple-cycle (SC) systems. Similarly, turbine cycles with TES systems consume more fuel, but produce more power than non-TES systems with the same cycle. Emissions per unit of steam production (kg/klb) follow exactly the same pattern as total emissions because steam production is the same for all systems. When emissions are presented per unit of electricity production (kg/MWh), however, the rankings change. The CC systems have lower emissions than SC systems, and TES systems have lower emissions than non-TES systems with the same cycle. The rankings can be explained by the lower heat rates of CC systems compared to SC systems, and the lower heat rates of larger turbines used for the TES systems compared to the non-TES systems. This latter advantage is offset by relatively poor waste heat recovery for the CC/TES application, however. Therefore, emissions per MWh for TES and non-TES CC systems are about the same.

**Table 11. Cogeneration System Emissions**

System Description	NO <sub>x</sub> Emissions	CO Emissions	TSP Emissions	Units
24 hr CC/Cogen	4450	301	150	Mg/yr
	1.449	0.098	0.049	kg/klb
	4.886	0.330	0.165	kg/MWh
8 hr CC/Hitec Salt TES/Cogen	5302	358	179	Mg/yr
	1.726	0.117	0.058	kg/klb
	4.871	0.329	0.165	kg/MWh
12 hr CC/Hitec Salt TES/Cogen	5309	359	179	Mg/yr
	1.728	0.117	0.058	kg/klb
	4.872	0.329	0.165	kg/MWh
24 hr SC/Cogen	4181	282	141	Mg/yr
	1.361	0.092	0.046	kg/klb
	6.151	0.416	0.208	kg/MWh
8 hr SC/(Oil/Rock) TES/Cogen	4391	297	148	Mg/yr
	1.429	0.097	0.048	kg/klb
	5.884	0.398	0.199	kg/MWh
12 hr SC/(Oil/Rock) TES/Cogen	4390	297	148	Mg/yr
	1.429	0.097	0.048	kg/klb
	5.884	0.398	0.199	kg/MWh

## SUMMARY AND CONCLUSIONS

Thermal energy storage can help cogeneration meet the challenges of the 1990s by increasing the flexibility and performance of cogeneration facilities. Thermal energy storage also allows a cogeneration facility to provide dispatchable electric power while providing a constant thermal load. The first of two studies reported here focused on the relative performance and economic benefits of incorporating a

**Table 12. Cogeneration System Energy Inputs and Outputs**

System Description	Natural Gas MMBtu/year	Steam klb/year	Electricity MWh/year
24 hr CC/Cogen	8,319,744	3,072,000	910,863
8 hr CC/Hitec Salt TES/Cogen	9,912,320	3,072,000	1,088,527
12 hr CC/Hitec Salt TES/Cogen	9,926,400	3,072,000	1,089,807
24 hr SC/Cogen	7,816,320	3,072,000	679,680
8 hr SC/(Oil/Rock) TES/Cogen	8,208,640	3,072,000	746,240
12 hr SC/(Oil/Rock) TES/Cogen	8,207,232	3,072,000	746,112

diurnal TES system with a simple-cycle gas turbine cogeneration system to produce dispatchable power during peak- and/or intermediate-demand periods. The results showed that the conventional cogeneration system and the cogeneration plant combined with oil/rock TES produced steam at a lower cost than a conventional boiler plant operation as long as the electricity sale price remained above \$ 0.06/kWh. The break-even electricity price (at which the steam costs are the same for the different plant configurations) is \$0.035/kWh for the conventional cogeneration case, and \$0.045 to \$0.05/kWh for the cogeneration system combined oil/rock TES. This represents nearly a 40% reduction in the cost of peak power when compared to \$0.08/kWh for a gas turbine plant; and a 30% reduction compared to a peak power cost of approximately \$0.07/kWh for a combined-cycle plant. The oil/rock storage system for TES was found to be the most attractive option for the assumed thermal load quality. A higher quality of the assumed thermal load (e.g., at higher pressures and temperatures) was also explored (saturated steam at 3450 kPa or 500 psia) and the oil/rock TES still remained as the attractive option. The molten salt systems may

become more attractive in the future if the media costs are found to be lower than the assumed levels.

The second study evaluated the cost of power produced by a combined-cycle electric power plant (CC), a combined-cycle cogeneration plant (CC/Cogen) and a combined-cycle cogeneration plant integrated with thermal energy storage (CC/TES/Cogen). The two cogeneration systems were designed to serve the same process steam load. The value of producing electricity was set at the levelized cost for the CC plant, while that of the process steam was for a conventional stand-alone boiler. The results indicate relatively poor economic prospects for integrating TES with a combined-cycle cogeneration power plant. The biggest part of the problem can be attributed to the extremely close approach temperatures at the storage media heaters, which makes them large and expensive. Two potentially mediating factors should, however, be considered prior to formulating any final conclusions or hastily eliminating this system combination. First, the designs developed here were reasonably practical and would work, but were not optimized from a size or cost perspective. For example, increasing the approach temperatures for the storage media heaters might lower the media heater costs more than it would raise media storage costs. Quite simply, design optimization would improve the economics, perhaps enough to make the CC/TES/Cogen an attractive option for incremental peak power production. Second, the media heaters were based on conventional "shell-and-tube" type heat transfer equipment. Direct-contact of gas turbine exhaust with the storage media would permit a much closer approach temperature, while reducing the cost of the media heater by as much as a factor of five. This magnitude of cost reduction for the high-temperature media heater could result in economically more attractive CC/TES/Cogen applications. Therefore, further analysis of this system combination, and especially using direct-contact heat transfer equipment for media heating, is strongly recommended.

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