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ECONOMIC ASPECTS OF THERMAL POLLUTION CONTROL IN THE ELECTRIC POWER INDUSTRY

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ECONOMIC ASPECTS
OF THERMAL POLLUTION CONTROL
IN THE ELECTRIC POWER INDUSTRY

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I. Introduction

One of the consequences of producing electrical energy in steam-electric plants is the production of large quantities of waste heat. In accordance with State-Federal Water Quality Standards for water temperature, this waste heat must be controlled. Several avenues of waste heat treatment and disposal are available:

1. Direct discharge of heated cooling water to the aquatic environment after circulation through the power plant condensers, i.e., once-through cooling.

2. Dissipation of heat to the atmosphere through the use of cooling devices such as towers or ponds.

3. Use of the waste heat for beneficial purposes, e.g., irrigation; industrial/chemical processes; aquaculture, etc. Here too, most of the waste heat ultimately goes into either the water or air.

4. Combinations of the above.

Considering the fixed or diminishing supply of the nation's fresh-water resources and the forecasted increase in thermal power generation, one is led to conclude that once-through, fresh-water cooling is unacceptable for large, new thermal power plants. Similar conclusions are voiced by industrial spokesmen. At the second session of the National Symposium on Thermal Pollution in August, 1968, Shade and Smith (8) stated: "Run of River and Bay/Lake systems for rejecting power plant thermal discharge have a very limited future because of government restrictions."

In a paper presented at the American Power Conference in April, 1969, Hauser (5) concluded that by the late 1970's the fresh-water bodies will ". . . reach a point where no further heat can be injected into them without damage to the ecology." Therefore, ". . . the only natural heat sink left will be the oceans." Hauser states that ". . . approximately 31%" of the thermal power generation capacity will be able to utilize sea water cooling. Thus, he concludes ". . . that during the end of the 1970's approximately 70% of the new base load generation to be installed in this country will utilize some form of supplementary cooling apparatus."

Most new thermal power plants will use cooling devices. The purpose of this paper is to discuss the economic impact of cooling -- how it affects the power industry and the consumer.

II. Cooling Systems

Cooling water systems can be divided into two major categories:

1. Once-through Systems. In a once-through system the cooling water is taken from a water body, passed directly through the condenser where it extracts energy from the condensing steam and is discharged back to the receiving water at an elevated temperature. Generally, the temperature rise between individual once-through systems varies from 10^{o} to 25^{o} F and averages about 15^{o} F. The amount of thermal energy discharged to the receiving water is a function of plant size, thermal efficiency and load factor.

Single pass condensers are normally used in once-through systems. The size, or surface area, of a single pass condenser is inversely proportional to the log mean temperature difference (ΔT) across it (1).

$$\Delta T = \frac{T_2 - T_1}{\ln \left(\frac{T_s - T_1}{T_s - T_2} \right)}$$

Where, ΔT = log mean temperature difference

T_1 = incoming cooling water temperature

T_2 = leaving cooling water temperature

T_s = steam condensing temperature

The steam-condensing temperature controls the turbine back pressure which directly affects the plant thermal efficiency. An increase in T_s will increase the turbine back pressure and lower the plant efficiency. Since condenser costs increase with size, requirements for small ΔT's will result in higher condenser costs. Also, given a fixed condenser size, a decrease in the desired temperature rise will require a higher cooling water flow rate and thus increase pumping requirements.

2. Closed-cycle Systems. Closed-cycle systems use an "off-stream" cooling device to reduce the temperature of the condenser discharge. Cooling water is used again and again, thus the terms "recycling" and "recirculation" are often used to describe a closed-cycle system. Evaporative cooling devices are most commonly used. Only relatively small amounts of make-up water are required from an outside source. The amount of make-up water required depends upon evaporative and blowdown losses. Blowdown is a process of removing water from the system

to prevent a buildup of dissolved solids in the circulating cooling water. Blowdown rates are a function of the concentration of solids in the source water and the rate of evaporation. Make-up water requirements are normally about 4% of the total cooling water flow, with evaporation accounting for 1 to 1-1/2% and blowdown for 2 to 3%.

Cooling devices operate more effectively when condenser discharge water is at a high temperature. Thus, a large temperature rise across the condenser is desirable. Temperature rises of $25^{o}$to 35^{o} F are not uncommon. Dual pressure, double pass condensers are required when large temperature rise and high cooling water temperature exists. If single pass condensers were used, the turbine back pressure would be too high and the plant efficiency would be decreased. For 1000 MW nuclear plant, Battelle-Northwest (1) estimates the capital cost of single pass condensers at 2.1 million dollars whereas a double pass unit would cost 3.4 million dollars. The higher capital cost of double pass condensers is justified on the basis of optimizing overall plant cooling system efficiency.

In evaluating the effect of cooling facilities on the cost of a plant and on the cost of producing power, the cooling facilities should not be considered independently from the power generating equipment, but rather both must be considered as a complete package in any economic evaluation. Therefore, rather than look at each component of a power plant with respect to its individual effect on the total cost of producing power, a more useful approach is to compare the total "bus bar" costs of thermal power generation from plants employing several different types of cooling systems.

Five different cooling systems presently being used have been selected for comparison here:

1. Once-through Fresh-Water. This is the most common type of power plant cooling used at water-rich sites in the United States today, and it is usually the most economical both from the standpoint of capital cost and operating costs. Factors tending to influence the cost of once-through cooling are: control structures to prevent recirculation of heated cooling water through the system, i.e., skimmer walls , diffuser systems, long intake and/or discharge lines, and screening. Maintenance costs can increase because of abrasion of pipes and condensers caused by sediment-laden water and in preventing corrosion, algal growth, etc.

2. Once-through Sea Water. This system is similar to once-through fresh-water cooling, but its cost is increased by different condenser design and materials and the requirement for long intake and discharge lines. Battelle Northwest (1) reports a 19% cost increase for salt water condensers over fresh-water condensers of the same size. Richards (7) estimates the cost of discharge conduits at $500/ft. and a major West Coast power company puts the cost at $820/ft. for 10 ft. diameter conduits and $1000/ft. for those 14 ft. in diameter. Thus, the capital cost of intake or discharge line can vary from $500,000 to $1 million per 1000 ft.

3. Closed-cycle with Cooling Pond. Cooling ponds are large, artificial water bodies that transfer heat to the atmosphere through convection, radiation, and evaporation. This type of system is usually

more expensive than once-through cooling because of the cost of land required for the pond and the construction of the pond. In addition, the use of dual pressure condensers would increase capital costs.

4. Closed-cycle with Wet Mechanical Draft Cooling Tower. Evaporation, mechanical draft cooling towers transfer heat to the atmosphere primarily by evaporative heat loss, although convective heat exchange can account for as much as 25% of the total heat loss. Large fans are used to provide air movement through the packing, i.e. the heat transfer section of the tower. Capital cost of the tower structures, power costs for the fans, and increased condenser costs make this system more expensive than once-through cooling. Treatment of blowdown wastes may also add to costs.

5. Closed-cycle with Wet Natural Draft Cooling Tower. Large hyperbolic natural draft cooling towers are becoming familiar sights in the United States. These devices use the density difference between the incoming air and the air above the packing to promote the flow of air through the tower, so the costs of fans and power to operate them are not incurred. However, capital costs are greater than for mechanical draft units of the same cooling capability. Condenser requirements and blowdown waste treatment also add to the cost.

III. Cost Comparisons Among Cooling Systems

Table 1 presents data from several sources to compare the costs of power produced by plants using the various cooling systems described above. The cost of once-through fresh-water cooling is used as a base, and the other four systems are compared to this base. The numbers indicate the difference in total production costs (in mills per kilowatt hour). The effects of both capital and operating costs are reflected in these figures. The assumptions specified regarding plant load factor, interest rates, amortization, etc., are uniform for each column.

Table 1 indicates the economic influence of cooling systems but does not account for the variability in other factors which should be considered in minimizing power costs. Such factors as transmission distance and bond interest rates may have more effect on power costs than the choice of cooling systems. For example, Battelle-Northwest (1) states that a variation in bond interest rate of 1% is equal to a variation in unit power cost of 0.18 mills/KWH. This is the magnitude of cost involved in adding cooling towers (Table 1). Transmission costs vary with distance from the load center. Battelle-Northwest (1) cites a cost of about 0.3 mills/KWH per 100 miles of transmission. This figure is substantiated by the analysis of Hauser (5) who equates the cost of various cooling systems to transmission distance in miles. Hauser concludes that the additional cost of wet cooling towers, about 0.2 mills/KWH, is equivalent to a transmission distance of about 80 miles. These factors demonstrate that an overall optimization must be performed to minimize the unit cost of power from a new plant.

IV. Consumer Cost

The foregoing discussion has delineated the increase in production or bus bar costs (Table 1) for plants using various cooling systems as

TABLE 1

COST OF COOLING ABOVE THAT REQUIRED FOR ONCE-THROUGH FRESH-WATER SYSTEMS (Mills/KWH)

Cooling System	Hauser (5)	Battelle (1)	Converse (2)	Lof & Ward (6)
Once-through Sea Water	0.0336	0.023		
Cooling Pond	0.0331	0.092		
Wet Mechanical Draft Tower	0.1557	0.150	0.16	0.2 - 0.3
Wet Natural Draft Tower	0.1446	0.138		

The figures shown in Table 1 were derived from analyses which used the following assumptions:

Hauser (5): Based on estimated capital, operating, and maintenance cost for a typical U.S. 1000 MW nuclear plant; 14% annual fixed charge rate and 80% plant load factor.

Battelle (1): Costs are those determined in studies of 16 example locations suitable for siting 1000 MW nuclear plants in the Pacific Northwest. Analyses were performed on 18 cooling systems at the sites as follows:

Fresh-Water (Once-through)	-	6
Salt Water (Once-through)	-	6
Cooling Pond	-	1
Mechanical Draft Towers	-	1
Natural Draft Towers	-	4

Public agency financing was assumed (100% bonds . . . 4-1/2% effective interest rate); 80% plant load factor.

Converse (2): Costs are those used by Vermont Yankee Nuclear Power Corporation in evaluating plant and cooling costs for the proposed plant at Vernon, Vermont. Annual fixed charge rate = 8.42%; 85% plant load factor.

Lof and Ward (6): Analyses of costs of cooling under typical conditions in the United States.

compared to those using once-through cooling. Who pays for the increased costs? Naturally, the cost increases are borne by the consumer. It is important to note, however, that production cost variation is not the only factor influencing consumer costs. The amount the consumer pays for electric power is substantially higher than the actual production costs -- transmission, administration, maintenance, advertising, etc., all add to the consumer costs. In some cases the production cost may only be 20% of the consumer costs (2).

The Federal Power Commission has published information on 1966 consumer costs of electric power by all utilities. Data from several example utilities in various regions of the United States are shown in Table 2.

The wide variation in rates shown in Table 2 may be attributed to differences in the following areas:

1. Capital, production and delivery costs -- land, materials, labor, fuel, etc.

2. Finance and tax rates depend on the type of utility (public or private) and other economic factors.

3. Regulations -- State and/or Federal.

To demonstrate the impact of thermal pollution control on the consumer, one can compute the percent increase in consumer costs due to the increase in production cost. If one assumes that other charges are not affected by the type of cooling system, the data from Table 1 can be used with the data from Table 2 to make this calculation. For specific

TABLE 2
1966 CONSUMER COST OF ELECTRIC POWER (3,4)
(mills/KWH)

Utility	Industrial	Commercial	Residential
Commonwealth Edison of Illinois	9.91	21.87	26.84
Georgia Power Company	8.46	19.48	17.01
Los Angeles Department of Water and Power	8.60	12.92	20.12
San Antonio City Public Service Board	10.01	21.24	21.03
Southern California Edison Company	8.74	17.87	23.88
Texas Electric Service Company	9.78	18.83	23.55
Portland General Electric Company[1]	4.42	12.54	11.25
U.S. Average	9.78	21.29	23.40

[1]Hydro Base

utilities not listed in Table 2, data from the Federal Power Commission reports (3,4) can be used. Table 3 shows the effect of cooling system type on the electric power cost for the average United States consumer (based on 1966 prices). As in Table 1, once-through fresh-water cooling was used as the base. The consumer costs associated with the different cooling systems are compared to this base.

TABLE 3

PERCENT COST INCREASE FOR AVERAGE U.S. CONSUMER

Cooling System	Industrial	Commercial	Residential
Once-through Sea Water	0.34%	0.16%	0.14%
Cooling Pond	0.94%	0.43%	0.39%
Wet Mechanical Draft Cooling Tower	3.17%	1.41%	1.28%
Wet Natural Draft Cooling Tower	1.48%	0.68%	0.62%

These data were computed using the maximum figures from Table 1 and assume that the cost increase, in mills/KWH, is applied equally to industrial, commercial and residential consumer rates. These figures further assume that the cost of all the power purchased by the consumer will be increased in the same proportion as that produced by a single plant using the specified cooling system. Thus, the effect of merging a single plant into an existing power system is not accounted for. These assumptions tend to make the data in Table 3 conservative, i.e., the values are probably too high.

V. Conclusions

The foregoing data and analyses show that the cost of providing thermal pollution control is not a restrictive factor in the production of electricity. Incremental increases in the production cost of electricity from plants with closed-cycle cooling over those with once-through fresh-water cooling are not excessive. More importantly, the impact of thermal pollution control on the consumer cost of electricity is minimal.

Opinions which support these conclusions include:

Shade and Smith (8)

> "Cooling by means of closed systems such as cooling towers and captive cooling ponds is not prohibitive either in initial capital costs or operating costs, but these costs are not so low they can be ignored."

Lof and Ward (6)

> ". . . the additional on-site costs incurred by the power plant (and passed along, in turn, to the power users), due to recirculation cooling are only a small percent of total cost of electricity generation and distribution."

and Hauser (5)

> "The economic penalties associated with alternative cooling systems will not deter the electrical generation growth in this country."

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