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Analysis of Engineering Alternatives for Environmental Protection from Thermal Discharges

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March 1973

ANALYSIS OF ENGINEERING ALTERNATIVES

FOR ENVIRONMENTAL PROTECTION FROM

THERMAL DISCHARGES

By

State of Washington Water Research Center
University of Washington/Washington State University
Pullman, Washington 99163

Project 16130 FLM

Project Officer

Dr. Bruce Tichenor
Environmental Protection Agency
National Environmental Research Center
Corvallis, Oregon 97330

Prepared for

OFFICE OF RESEARCH AND MONITORING
U.S. ENVIRONMENTAL PROTECTION AGENCY
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ABSTRACT

This report summarizes a two year effort to develop an analytical framework to evaluate current and proposed engineering practices used in the protection of the environment from the impact of thermal power systems. The engineering practices modeled included the heat source/generating system, the electrical power transmission system, the water intake system, the cooling system and the chemical control of the water systems. An ecological accounting system was developed to provide a non-monetary measure of biological response to the engineering alternatives. Efforts to formulate a socio-economic accounting system to internalize externalities created by these engineering practices were unsuccessful. A computer model was developed employing a decision tree format to evaluate the environmental and economic impacts of these engineering alternatives for any given site. Methodologies available to assess the impact of a series of power plant developments in a region were evaluated and the Forrester type (1971) feedback simulation of a few variables was found to be best suited for dynamic assessment problems. Both static and dynamic analytical frameworks have been verified to be computationally correct, but an extensive demonstration program is required to prove their applicability.

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SECTION I

CONCLUSIONS

1. This research has identified a need for a systematic examination of the environmental impact of thermal power plants. Impact evaluations tend to be fragmented, lack systematic or holistic perspective, and are difficult to interrelate.

2. The results of this study include a model format for preliminary planning and evaluation of the environmental impact of thermal power plants that is systematic, holistic and consistent.

3. To augment economic evaluations in this model an ecological accounting system can be formulated based on the response of fish communities to environmental impact.

4. The engineering alternatives to protect fishes from fatalities in power plant intake structures are not as sensitive to cost as to proper design. A high cost system incorrectly designed may create more damage than a lower cost unit, correctly designed. Salt water intake protection systems may require new technological developments as these waters are abundant with eggs and larvae of valuable fishes that can penetrate existing screens. Alternatively, the use of recirculating cooling facilities will reduce the demand for make-up water and the impact of intake structures.

5. The decision tree format provides a systematic framework to evaluate engineering alternatives and their environmental impact. This procedure has a disadvantage that feedback and iterative decision making is deleted but it offers consistency and simplicity of analysis of a complex situation.

6. Dynamic assessment of the second and third order impacts of a thermal site decision can best be made by using feedback-loop structure models with a minimum number of parameters. These models can be constructed, modified, and applied inexpensively, yet they provide much insight concerning dynamic environmental impacts.

7. The major problem encountered in developing a format for environmental impact assessment of thermal power plants is the fragmented studies that focus in great detail on fairly restricted problems. There is insufficient information to create a detailed description of the overall problem, thus the only alternative is to develop less detailed general models that emphasize interactions among processes rather than a simple process.

SECTION II

RECOMMENDATIONS

1. As originally proposed, this study was one of two parts. The complementary study to verify and test these models in practical applications must be conducted before the models can be evaluated.

2. Planning and evaluation is not a single action but a continual process that responds to changing technical advances, demographic and economic conditions, and social values. There is a lack of methodology available to conduct continuous assessment at a reasonable cost. The results of this study are only a start in the development of evaluation techniques that are responsive to changing conditions. Further development of these techniques is required if environmental impacts of thermal power plants are to be properly evaluated.

SECTION III

INTRODUCTION

Man's attempts to engineer the environment have been myopic with each new solution creating a problem of equal or larger magnitude. In an attempt to increase the vision used in planning new thermal power generating facilities, the State of Washington Water Research Center in 1970 proposed a nine task program to analyze the institutional and information constraints that create the myopic vision encountered in power plant siting, to formulate a methodology to clearly assess the engineering alternatives, and to verify the methodology that was developed. The nine tasks originally proposed are listed in Table 1.

Only tasks 1, 2, 3 and 7 were funded and the level and duration of funding required that graduate students rather than faculty conduct the study. A graduate student and faculty advisor were assigned to each task and theses or reports were usually produced as a by-product of the research: Bush *et al*. (1972), Geitner (1972), Meyer (1972), Porter (1972), Saad (1971). This project report summarizes and integrates the results of these studies.

The specific goals of the funded tasks were:

1. A computerized model that defines the thermal discharges, the chemical discharges, the resulting physical environmental impacts, and the costs for a baseline 1000 MWe power system.

2. The development of economic, social and ecological accounting systems for use in the evaluation of the effectiveness of engineering alternatives for the protection of the environment from thermal power system discharges.

3. The collection of data and formulation of a model that describes the cost, performance and environmental impact of engineering alternatives used in the protection of the environment from thermal power systems.

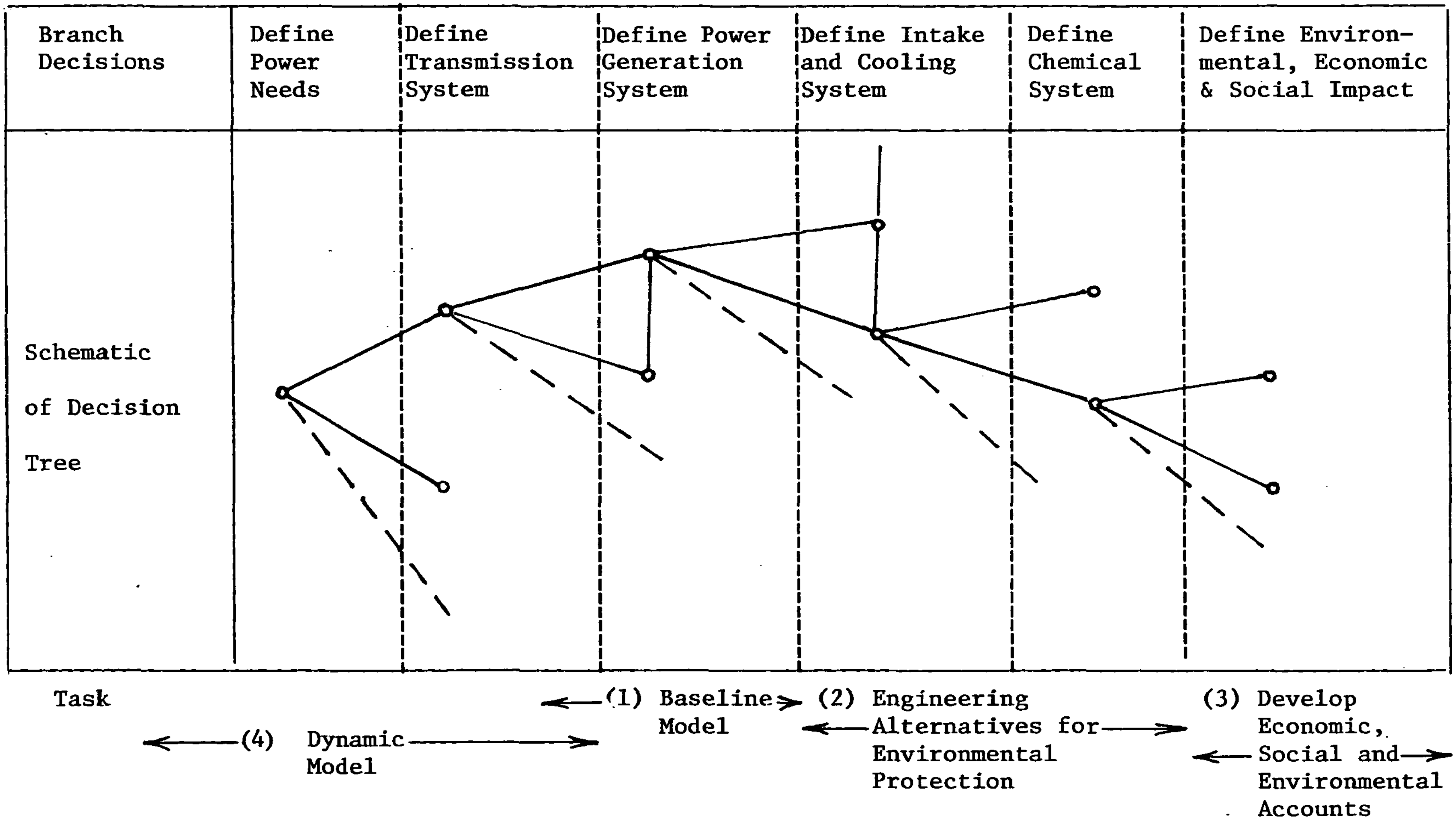
Table 1. Summary of Proposed Work

Task	Purpose	Procedure
Baseline Definition 1. Document existing once through thermal power plant environmental impact	Provide economic, ecological and social baseline for study	Use FWPCA, BPA, and industrial data plus literature
Environmental Accounting 2. a. Develop ecological environmental accounting system and define ecological response	Many changes cannot be valued in dollars; must use some quantitative measure	Survey literature, current research, and expert opinion, and then develop
b. Develop social accounting system and social response	Relate economic and environment change to social value system	Economic-social research study
Alternative Engineering Solutions 3. Define current alternatives for control of environmental changes from thermal power plants	Provide models for evaluation	Survey of FWPCA, BPA, EEI, etc. studies
Environmental Analysis 4. Examine environmental effectiveness of alternatives for 4 selected cases	To define subsequent changes necessary to protect environment	Employ output of Task 2a and computer system analysis, etc.
Social Analysis 5. Examine social effectiveness of alternatives for 4 selected cases	To define subsequent changes necessary to protect environment	A team of socio-economic researchers will conduct the analysis using computer analysis
Engineering Analysis 6. Evaluate economics of primary plus secondary actions necessary to achieve environmental quality	Determine effectiveness of total required alternatives	A team of ecology and water quality experts will evaluate the environmental response
Dynamic Analysis 7. Examine dynamic implications of multiple-plant system on environment	Determine if single plant criteria is optimum	Use models in DYNAMO analyzing gaming studies
Critique 8. Analyze results of analysis and recommend management alternatives	Discuss results	The interdisciplinary team will focus on this task
Report 9. Prepare final report		

4. The development of a dynamic or sequential analytical framework to assess the environmental impact of a series of thermal power plants in a region.

A decision tree was employed as a focal point for integration of the task outputs, and as the format for the final static siting computer model. This format is schematically presented in Figure 1.

Figure 1. Management of Project Tasks and Outputs



SECTION IV

SINGLE PLANT ASSESSMENT

LITERATURE REVIEW

History and Problems of Thermal Power Plant Siting

Geitner (1972), as part of this research effort, reviewed an extensive list of literature relevant to thermal plant siting problems, engineering alternatives and environmental impact of thermal power plants. The results are presented and analyzed in this section. Thermal power plant siting has progressed largely on an *ad hoc* basis throughout most of the history of the electric power industry. Traditional trade-offs among prospectively sites for fossil-fueled power plants have been between fuel costs and transmission costs. Little attention was paid to the externalities of thermal power generation with the exception of the soot problems experienced with early plants which, combined with limited land availability and high land cost, forced the thermal plants outside the cities. Externalities were not perceived in the early years of power development to be a problem principally due to their small magnitude and very localized impact. The number and density of plants was small. The size of generating stations was also small.

As the magnitude of electric power production grew, the number and density of thermal generating plants increased. Although the accompanying environmental impact, which had been small and localized, increased noticeably, it still was not a factor considered in siting decisions. Gilleland (1969) presents a list of siting parameters in his article concerning Tennessee Valley Authority (TVA) siting experience. The parameters discussed were:

1. Load Center
2. Fuel Transportation
3. Transmission Lines
4. Aesthetics

5. Exclusion Area
6. Meteorology, Hydrology, Geology and Seismology
7. Cooling Water Supply
8. Access

Noticeably absent from this list of traditional engineering and economic parameters is direct mention of environmental impact. Only the categories of aesthetics and exclusion imply consideration of some measure of environmental impact. Gilleland included in his discussion a statement that a properly chosen site should not necessitate the use of cooling towers. Seemingly, utilities continued to view the cooling tower as an engineering solution to the scarce water problem rather than an alternative solution to prevent adverse environmental impact from thermal discharges to native receiving water bodies.

Thermal discharges to receiving waters increased despite improvements in plant efficiencies. Older, less efficient plants became a smaller percentage of the generating capacity, and added, efficient, new plants soon over burdened receiving waters. The introduction of water-cooled nuclear central generating stations actually placed a larger burden of heat rejection per unit electrical output than an electrically equivalent modern fossil-fueled unit. These facts and other basic thermally related problems were discussed in the "Industrial Waste Guide on Thermal Pollution" by the Federal Water Pollution Control Administration (FWPCA, 1968). Larger generating plants began to remove sizeable portions of the rivers for condenser cooling water and the subsequent increases in river temperature caused concern over the health of the resident aquatic community. The Division of Reactor Development and Technology, U. S. Atomic Energy Commission (AEC), 1971, published a summary document concerning thermal effects and nuclear power stations. Table II of the AEC report is summarized in Table 2 to show the impact of increasing station size on the water requirements and the associated relationship to the adjacent river. While the table is not inclusive, it does demonstrate that certain sited plants have the potential to remove sizeable quantities of the

Table 2. Nuclear Power Plant Cooling Requirements and River Flows

Plant	Location	Cooling Water Requirements (cfs)	River Flows (cfs)		Ratio of Cooling Water Required to Low Flow (%)
			Low Flow	Average Flow	
Dresden Station	Illinois River, IL	2,660[a]	2,694	8,000	99
Monticello	Mississippi River, MN	623[b]	220	3,200	283
Quad Cities	Mississippi River, IL	2,100	12,096	50,000	17
Cooper	Missouri River, NB	1,450[c]	4,320	20,000	34
Fort Calhoun	Missouri River, NB	702	3,000 to 5,000	25,000	23-14

Ref: Table II, AEC (1971)

Key:

a 430 cfs once-through for unit 1. 2230 cfs variable-cycle flow-through cooling pond for units 2 and 3

b To use variable cycle, mechanical-draft cooling tower system

c To use cooling pond

adjacent natural flowing river. The table shows however, that some of the plants use once through or partially recirculating cycle condenser cooling devices to reduce the amount of water withdrawn from the river.

Table 3 presents results of studies by Levin et al. (1972) at nine thermal power plants operating in various environments. Of the nine sites only one, Turkey Point, Florida, has experienced large biological impact on the receiving water. It should be noted that some of the plants discussed are small and are located on relatively large water bodies. While the results of their survey of the aquatic impact of thermal power plants is not complete, it does elucidate the point that properly sited thermal power plants may cause minimal environmental impact. The difficult questions remaining are those concerning determination of sublethal effects and determination of criteria for defining a properly placed plant. Or, as an opposite accomplishment, what information is necessary to fairly precisely define the places where it is environmentally unwise to construct a large thermal power plant?

Existing Modeling Efforts for Assessment of the Impact of Thermal Power Plants

Three comprehensive modeling efforts were found to exist in the literature. Two of these efforts involved application of linear programming techniques, Mark and Borenstein (1970) and Millham (1971). The third method by Fields (1971) involves use of graph theory methods. A good description of linear programming and its applications can be found in Daellenbach and Bell (1970) or Hillier and Liebermann (1967). Graph theory and its applications are discussed in Berge (1962) and Busacker and Saaty (1969).

Marks and Borenstein (1969) used a specialized form of linear programming to analyze thermal power plant siting. This model set out to find:

1. Optimum number of generating sites
2. Optimum size of generating plants

Table 3. Biological Survey Sites Discussed by Levin, et al. (1972)

Site Name	Size (MW_e)	Water Body	Noticeable Detrimental Effects
Hanford, WA	various	Columbia River	none
Chalk Point, MD	2 x 335	Patuxeut River Estuary	no major changes
Contra Costa, CA	1298	San Joaquin River	no major changes
Morro Bay, CA	1030	Pacific Ocean	none
Humboldt Bay, CA	172	Humboldt Bay	none
Connecticut Yankee, CT	562	Connecticut River	no major changes, not enough information about sublethal effects yet
Turkey Point, FL	2 x 432	Biscayne Bay	1. 125 acre area + 4°C kill area 2. 170 acre area + 3°C algal growth disturbed; diversity and abundance shifts
Petersburg, IN	220	White River	only fish avoidance of 93°F plume water
Martins Creek, PA	not given	Delaware River	none

3. Optimum location of generating plants

The objective function for this work was minimization of total cost (defined as capital costs plus lifetime operating costs). The constraints placed on the solution were:

1. Predicted power demands of the region must be satisfied.
2. Temperature standards for receiving waters must not be exceeded.

The model equations and explanations appear in Figure 2.

The formulated problem was solved for the integer case only. The performed solution was not a temporal one. It is similar to the basic transportation problem formulation of linear programming with an added temperature constraint and imposition of integer solution variables. It addresses the question of optimum plant size with respect to a temperature constraint only. It is a good beginning effort that is bounded by: (1) its static nature, (2) its treatment of only a limited size system (no allowance for outside trading of power), and (3) solution of only a hypothetical test case.

Another linear programming model was developed by C. B. Millham (1971) as part of an environmental Research Center, Washington State University (1971) research proposal to the National Science Foundation. It is a formulation very similar, but not identical to, a time base resolution form of the transportation problem form discussed in Hillier and Liebermann (Ch. 6, 1967). Its mathematical formulation is shown in Figure 3.

This formulation is called the Capacitated Plant Model. It seeks to minimize the cost of supplying power. The formulation divides the objective function as shown into three parts:

1. Capital Costs
2. Transmission/Peak Costs
3. Operating/Base Energy Costs.

Objective Function:

Minimization of total costs

$$\sum_j [X_i F_i + \sum_j Y_{ij} L_j (P_j + T_{ij} + D_j)]$$

Constraint Equations:

Satisfaction of region load

$$\sum_j Y_{ij} L_j \leq X_i M_i$$

Receiving water excess temperature limit

$$\sum_i A_{ik} \cdot R_i [\sum_j Y_{ij} L_j] \leq C_k$$

Where:

F_i = Summation of intercept capital costs at site i (\$/wk)

X_i = Integer plant selection coefficient (0,1) and $\sum_{i \varepsilon S_m} \leq 1$

S_m = m^{th} set of plant alternatives

Y_{ij} = Load assignment coefficient (0,1) for all i, j

L_j = j^{th} load (MW)

P_j = Load dependent production cost rate (\$/MW-wk)

T_{ij} = Total transmission cost (\$/MW-wk)

D_j = Distribution cost rate (\$/MW-wk)

M_i = Maximum generating capacity for site

A_{ik} = Temperature transfer coefficient

R_i = Temperature rise at site i

C_k = Permitted excess temperature at location k

i = site index

j = load index

k = temperature monitor location index

Figure 2. Equation Set and Key for Marks-Borenstein Model

Objective Function:

Minimization of total cost

$$\sum_{i=1}^{m} f_i Y_i + \sum_{i=1}^{m} \sum_{j=1}^{n} C_{ij} X_{ij} + \sum_{i=1}^{m} \sum_{j=1}^{n} C_{ij} Y_{ij}$$

Constraint Equations:

Total generation is bounded by (peak capacity) x (load factor)

$$\sum_{j=1}^{n} X_{ij} \leq K_i \cdot F_i \cdot 8760$$

Summation of peak demands is less than or equal to source capacity

$$\sum_{j=1}^{n} Y_{ij} \leq K_i Y_i$$

Summation of energy sources equals or exceeds load center energy demand

$$\sum_{i=1}^{m} X_{ij} \geq e_j$$

Summation of individual peak demands equals or exceeds peak demand value

$$\sum_{i=1}^{m} Y_{ij} \geq d_j$$

Where:

f_i = Plant i amortized construction cost (\$/kW-yr)

C_{ij} = Plant i operating cost (\$/kW-yr)

Y_i = Plant i allocation coefficient, constrained to 0 or 1

X_{ij} = Energy transfer (non-peak) plant i to load j (kW-yr)

Y_{ij} = Peak demand transfer plant i to load j (kW-yr)

K_i = Plant i peak load capacity (kW-yr)

F_i = Plant i load factor (%)

e_j = Load j energy demand (kW-yr)

D_j = Load j peak demand (kW-yr)

Figure 3. Equation Set and Key for Capacitated Plant Model

The constraint functions are structured so that all base and peak load demands are met.

This model is a temporal one but its complex design with respect to peak and base loads negates treatment of environmental parameters. These are left to be specified exogenously. This formulation does not account for any time changing values for siting and transmission cost. A sample case has been run utilizing data from the Harty, et al. (1967) study to seek an answer only with respect to economic considerations. It should be viewed as useful only for this purpose. Additional constraint relations would have to be developed for it to be useful in environmental judgments of alternative sites for thermal power generation.

Fields (1971) developed two algorithms for scoring alternative methods of heat disposal for steam power plants. Fields' methods generate:

1. Cost/Benefit ratios for heat disposal systems
2. Ancillary effects scores for heat disposal systems
3. A decision process for selecting a best heat disposal system based on 1 and 2 above plus a cost ceiling

Both algorithms are based on a graph with three dimensions. The dimensions of the model are methods of heat disposal, M_i, characteristics of the receiving water, C_i, and hydro-environmental effects, E_i. Figure 4 shows the graph and its components. A pseudosystem, WQS, is defined for the M_i dimension to furnish a standard for comparison of the various M_i.

Fields' algorithms do not attempt to calculate microvalues or discharge quantities. His algorithms are decision tools only. Expert decision makers in the three perceived fields are needed to supply information to the decision system. Opinions of participating experts are used to establish:

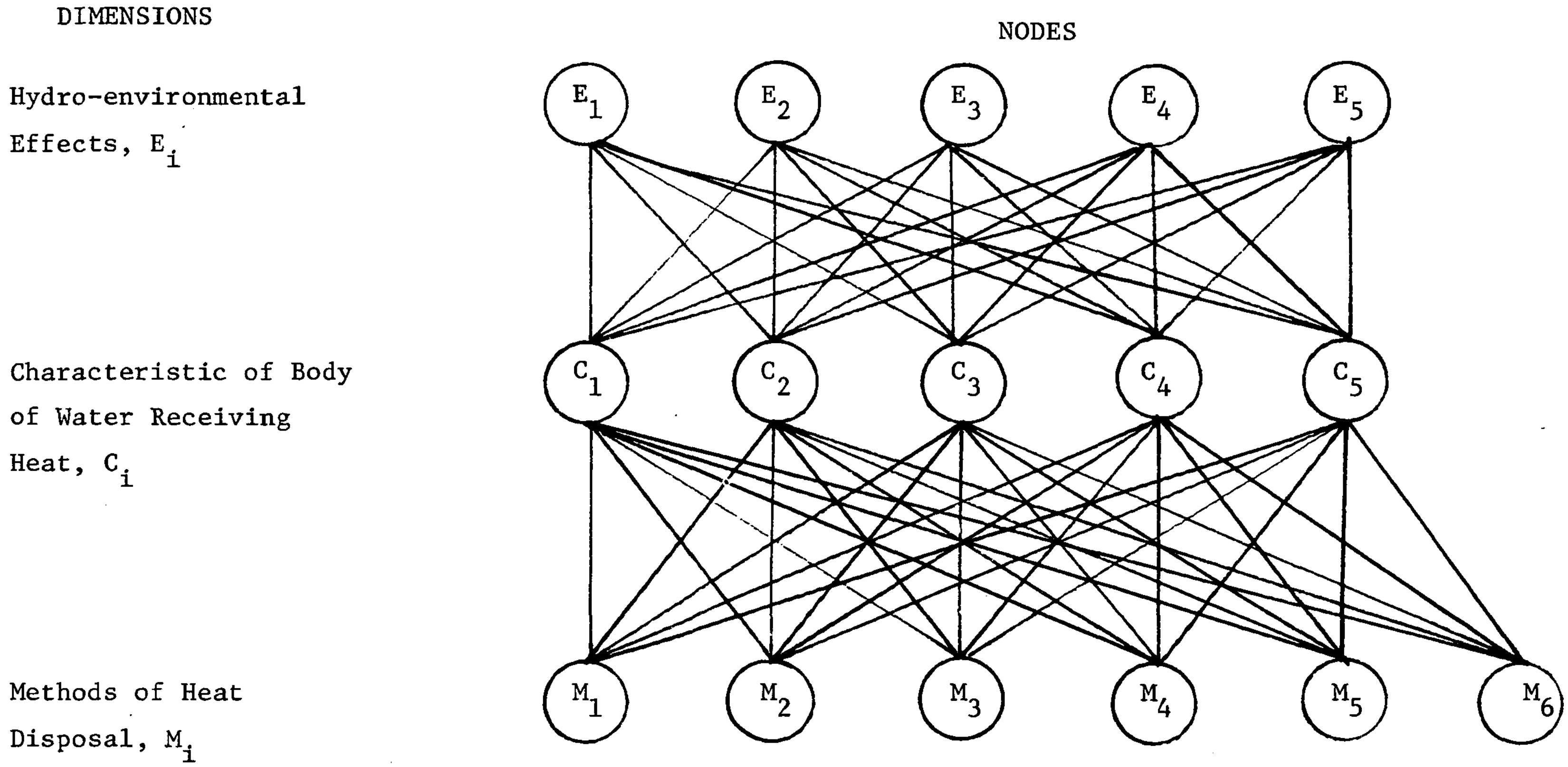


Figure 4. Basic Components in Fields Decision Model

1. Dimensions of the graph (the number of M_i's, C_i's, E_i's)

2. Sets of constant-sum preference decisions rating the interaction factors between respectively M_i and C_i, and the C_i's and the E_i's.

3. Ancillary effects dimensions and importance for use as a secondary decision variable.

The M_i's reflect the different possible condenser cooling means considered for a given site. The C_i's represent the different types of water bodies under consideration (e.g. river, estuary, ocean, lake). A set of hydro-environmental effects might include:

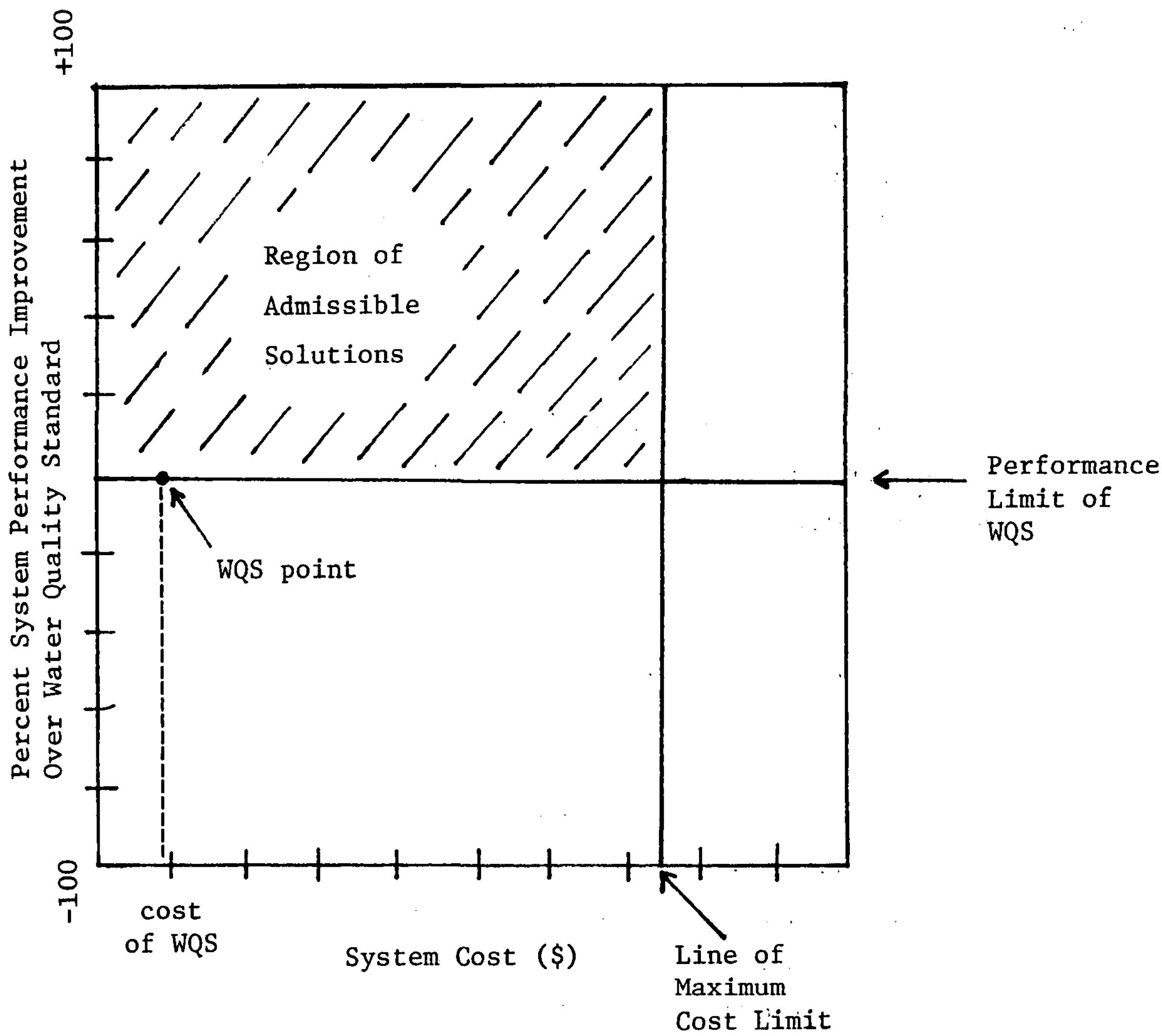
E_1 - Effects on fish
E_2 - Effects on plankton
E_3 - Effects on benthos

Interaction parameters between the dimensions are entered as constant-sum decision pairs. Information on intralevel interactions and interlevel interactions are input to the model as constant-sum paired decision comparisons. The two algorithms differ in the level of information detail and calculation procedures for interaction parameters.

Both methods share a common decision rule set for selection of the optimal M_i. The principal decision criteria is the cost/benefit ratio. This ratio is determined by dividing the system cost ($) by the percent system performance compared with the performance of the Water Quality Standard (WQS) pseudosystem. Equation IV-1 gives the cost/benefit relation.

$$C/B_i = \frac{\text{Cost of System } M_i}{\text{\% Performance better than WQS}} \tag{IV-1}$$

The WQS standard is evaluated in the method and is considered as the minimum performance limit. Two secondary decision variables are the ancillary effects scores for the various M_i's and the upper cost bound. Figure 5 shows how the region of acceptable solutions is defined and



Note: Scales and bounds are arbitrary and are for illustrative purposes only.

Figure 5. Graphical Definition of Admissible Solutions for Fields' Model

bounded. System performance worse than the WQS is not acceptable.

Acillary effects criteria (land use, visual impact, and air discharges for example) are significant only for deciding among M_i's with close C/B ratios. The ancillary effects scores are not viewed as controlling parameters.

Total system cost is the final bound on the optimal solution. After determining the C/B ratio for a given M_i the system cost is compared with the specified maximum cost. The solution is not allowed if the cost exceeds the maximum value.

Fields' methods are only preliminary planning tools. The decision process emphasizes aquatic impacts which may not be the controlling factor for a given site. Fields' classification of receiving water characteristics is too coarse to be of benefit at any given site or for deciding among a set of competing sites. To be of use for a particular site the characteristics category would have to include several of the usual water quality parameters used to describe water quality at a site (e.g. temperature, dissolved oxygen, dissolved solids). Fields' method relies heavily on exogenous inputs from experts in the related problem areas. There is no control over the methods used to determine the input to the model.

Previous Regional Siting Studies

Electric utilities and related government agencies began to realize that expansion of already large power systems implied increasing siting problems. On the West Coast two comprehensive but different studies were undertaken to assess the status of thermal power plant siting (Harty et al., 1967, and The Resources Agency, State of California, 1970). The Committee on Power Plant Siting, National Academy of Engineering (NAE), "Engineering for Resolution of the Energy-Environmental Dilemma," (1972), released their findings as this study was concluding. Not all of their results could be incorporated in this work. Both the Pacific Northwest and California had always been areas where power had been plentiful. Bonneville Power Administration (BPA), a regional wholesale distributor of electric power, contracted with the Pacific Northwest Laboratories of Battelle Memorial Institute to conduct a study of prospective nuclear power generating sites. The resultant study by Harty _et all_ (1967) considered the viability of siting 16 nuclear power plants throughout the Pacific Northwest on a site-by-site basis.

The 1970 Resources Agency study was not a site-by-site analysis of thermal siting in California, nor did it review with great detail the characteristics required for a site. Instead it reviewed the need for further development of nuclear power plant sites and encouraged continued, cooperative planning among the various public and private electrical utilities in the State. This overview study did establish some policy measures which demonstrate the multiplicity of problems predicted for future power plant siting efforts.

1. An environmental protection agreement with the State Resources Agency must be consummated as a condition of construction of all new thermal power plants.
2. Future siting must be compatible with objectives of planning and zoning authorities.

Harty _et al_. (1967) considered the following factors in studying the 16 example sites:

1. Technical feasibility from geological, hydrological, seismological and meteorological standpoints
2. Economic feasibility
3. Ease of approval by regulatory agencies

4. Minimization of adverse public and government agency reactions
5. Illustrative problems typical of the Pacific Northwest environment

Two factors specifically not included by Harty _et al_. were transmission and land acquisition costs.

Reflecting then current power plant design practices, 11 of the sites proposed by Harty _et al_. were planned for once-through condenser cooling with five sites using recirculating cooling systems in locations where a water shortage was seen to exist. Once-through cooling was recommended even though the following statement was issued at the beginning of the report:

> "Biological effects associated with thermal discharge are sufficiently defined (though not completely understood) to allow identification of sites and designs of heated effluent systems that minimize effects upon _many_ aquatic species and communities. Insufficient information is available to predict with confidence all of the significant effects of heated discharges on aquatic life in the PNW (Pacific Northwest)."

The criteria used by Harty _et al_. to determine the applicability of once-through cooling must be questioned. Of the 11 once-through cooling sites, two sites are currently under preparation. The Trojan site near Rainier, under construction, will utilize a single, large natural draft evaporative cooling tower. Hanford II, on the Hanford Atomic Energy Commission Reservation, will use mechanical-draft evaporative cooling towers. Much of the pressure for cooling towers comes from lack of understanding of thermal effects. The cost figures set forth by Harty _et al_. (1967), which were claimed to be reliable for one decade are also out of date.

In view of such inadequacies in previous comprehensive power plant siting analyses, a need was perceived for a complete, comprehensive definition of the effects of a baseline thermal power system. The literature of the various disciplines indicated little interaction and collective synthesis. It was felt that an overview, comprehensive type project might provide info rmation necessary to analyze the current status of the collective fields involved in thermal power plant siting. This definition would be keyed to identifying the interaction pathways between the power plant system and the environment and have the characteristic of continual up-dating. Such a definition could then be used as a starting point for analysis of plant/site interactions.

Considerable benefits were seen to accrue from an assembly of a multi-discipline team to examine the thermal power plant as a complete system from the generating station to the distribution point. The goal of the study was to quantify the impact of the thermal power generating system wherever possible so that trade-offs could be evaluated with some degree of certainty. Where effects could not be quantified or defined, it was hoped that a comprehensive listing of data insufficiencies could be assembled for the identifying and guiding of new research projects.

DECISION TREES AS AN ANALYTICAL FRAMEWORK

Decision trees have been employed as a systematic method to define and analyze sequential decision making that involves a hierarchical structure of choices. The literature is rich with the theory and application of decision trees. Poage (1970) presents a concise review and Raiffa (1968) discusses the analysis of decision making in the presence of uncertainty. Figure 1 presents a decision tree for the analysis of engineering and planning decisions for thermal plant siting. A node in the tree represents a decision point and the branches indicate alternative decisions that can be made and the resulting outcomes. The outcomes can be interpreted as deterministic or probabilistic events. By tracing any given path through the tree, the final result of any given set of decisions becomes apparent.

The tree serves as an information organization and transfer device (each stage adds to its input information and passes the result on to the next stage). The tree also transforms the externally supplied and internally generated information into final outputs (costs, quantitative environmental discharges, land use data, and thermal impact) for each alternative path evaluated.

This decision tree relates the alternative engineering decisions sequentially to the ultimate environmental and sociological impacts. This method permits the analysis of a large number of alternative decisions in a logical sequence. The ecological and sociological effects are keyed to the engineering decision chain. The decision chain proceeds from left to right. Knowledge from the left side of the tree is used to specify the operation and performance of the next level to the right. Thusly, sociological and environmental effects are developed as the last element or payoff. All engineering alteratives must be specified before the sociological payoff can be accurately specified. The level of complexity of the tree increases with the detail of engineering analysis specified.

The static siting model (SSM) developed in this study is a computerized tool employing a decision tree format to specify inputs concerning a particular power plant siting analysis and to evaluate the various environmental impacts through the siting tree. The SSM does not attempt to determine an optimum system for a particular site or plant. Its purpose is to display at a preliminary stage the spectrum of possible impacts accruing from alternative engineering courses of action.

The ordering of the thermal discharges tree is based on information flow requirements. The first and most basic level for single site analysis is the site/transmission path level. Parameters concerning access and on-site environmental conditions are required before accurate appraisal of engineering systems can be undertaken. The next level specifies the plant type under consideration. This level follows logically after the site information. Plant operating information must be available before cooling system performance (level 3) can be calculated. Following an evaluation of cooling system performance, screening calculations can be made. Only after specification of plant type, cooling alternative and screening system can complete evaluation of the power plant's chemical system be analyzed. The complete spectrum of decision alternatives encompasses:

1. Sites/transmission path
2. Plant types
3. Cooling systems
4. Intake systems
5. Chemical systems

The environmental and social payoffs are a function of the particular path evaluated. The SSM is capable of demonstrating variance in impact of the alternative decision paths.

TASK 1: BASELINE DEFINITION

The Baseline definition provides a reference point for comparison of engineering alternatives to reduce the environmental impact of thermal power plants. The Baseline configuration represents one path on the decision tree that contains a 1000 MWe gross steam cycle, once-through river cooled plant, with screens to protect the plant from damage, chlorine treatment of cooling water, and a submerged diffuser outlet. In the subsequent sections of this report each decision point of the tree is described indicating the analytical and computational models developed in this study, and the alternatives that can be examined.

Two rather than one baseline heat sources are available in the model. Either a nuclear water-cooled system or a fossil-fuel plant are available as baselines. All other systems can be analyzed by additional input statements describing the alternative heat sources. Table 4 presents the basic information describing the baseline configurations used in this analysis. The analysis of decisions through the cooling node employs the Dynatech (1971) cooling computer program. Much of the effort in baseline development was devoted to correction of this program and modification of the computer program to permit integration with the decision model. The decision tree has been constructed to permit alternative descriptions for the baseline characteristics shown in Table 4.

One of the early modeling decisions made in this study was the resolution of the data and information provided at each step in the decision tree. Information is provded to make inter-site comparisons at a gross level; there is no attempt to compare intra-site decisions to optimize engineering alternatives. For example, all water discharges are considered to be well mixed in evaluating thermal discharge effects, no attempt is made in the analysis to describe thermal plume behavior or the impact of floating or dispersing the heated effluent. These effects can only be incorporated at large costs, since the data requirements are increased many fold.

Table 4. Baseline Plant Characteristics

Heat Source	Nuclear	Fossil
Gross Electrical Output	1000 MWe	1000 MWe
Condenser Pressure	1.5 in Hg	1.5 in Hg
Condenser Temperature	91.7°F	91.7 °F
Gross Plant Heat-Rate	10,340 Btu/kw-hr	8,630
In-Plant Losses	5%	15%
Heat Discharge-Rate	6.4×10^9 Btu/hr	3.8×10^9 Btu/hr
Cooling	River-Once Through	River Once-Through
Chemical Discharge	.5 ppm Cl_2 Residual	.5 ppm Cl_2 Residual
Intake Screens	minimal	minimal
Cooling Discharge	Submerged diffuser	Submerged diffuser
Land	500 acres	500 acres

The thermal discharge model provided in this study integrates the results of FWPCA (1968), Hauser (1970, 1971) and Jaske (1971, 1972a, 1972b) with the Dynatech (1971) efforts. Five percent changes in heat rate have minor environmental impacts but create major thermal plant design changes.

Chemical discharges to the aquatic environment from the once-through cooled plant are a direct function of the intake water quality. Liquid chemical discharges emanate from either the circulating cooling water or untreated discharges from the steam system. The latter system in new plants has almost zero blowdown. Boiler water make-up is only required for system leaks and is generally less than 1 cfs. Complete discussions of cooling water chemical treatment processes and impacts on the aquatic community appear in Task 2 and Task 3 of this report.

Baseline plant condenser cleaning is assumed to be by the method of intermittent, break-point chlorination. While some plants are using mechanical means (abrasive balls), chlorination was seen to be a more typical method.

The high flowrate open systems for once-through cooling prohibit the use of a high concentration of chemical treatment and cleaning agents. Intermittent break-point chlorination has proven and effective means for control of biological fouling. The dose required to achieve break-point or free-residual chlorination dose is a function of the inlet water quality. The presence of both reducing compounds (Fe^{++}, Mn^{++} and H_2S) and ammonia (NH_3) affect the necessary dosage. Their uptake requirements for the chlorine must be satisfied before an uncombined residual is available for biofouling control. Metcalf and Eddy (1972) give a dose range of 1 to 10 mg/l of Cl_2 for these applications. Cooling waters containing large industrial, agricultural or municipal waste loads will require doses at the upper end of the range to achieve satisfactory results. The dose period typically is short (20 to 30 minutes) with a frequency of 2 to 3 times daily.

The residual chlorine concentration is a function of the dose necessary to achieve the free residual. For the new plant at Hanford, WA, a residual value of 0.5 mg/l is predicted using the relatively clean Columbia River in a recirculating cooling system (WPPSS, 1971). A similar value would be valid for a once-through system at the same location.

The baseline model assumed a residual of 0.7 mg/l unless an input value is specified. This value will be reduced by uptake of slime growths in the condenser system. The uptake of chlorine by the slime growths is a difficult parameter to model being a function of contact time and slime concentration. Ideally, chlorine would be dosed so that all free residual was absorbed within the confines of the condenser system for a time period that would either limit slime growth to a negligible level or kill it all together. The chlorine residual in the cooling water discharge is subject to EPA regulation. Current recommendations are for a residual of 0.1 mg/l for not more than 30 minutes per day or 0.05 mg/l for not more than 2 hours per day. If the dosage can be regulated to these levels, no additional treatment or costs will be necessary. Dosing costs are derived from the work of Smith (1967). Extra costs incurred to meet the standard are not a part of the baseline system. These cost constitute treatment above baseline and can be accommodated in the chemical treatment branch of once-through cooling.

Physical environment changes are varied and are, in general, difficult to quantify. While Thackstone and Parker (1971) give a number of from 75 to 100 acres as the minimum plant size for a nuclear generating station, most plants are located on larger sites. The baseline plant model assumes 500 acres as a base fingure for land use. Nuclear plants impact land use further by requiring certain population density zones around the plant to correspond with plant design requirements.

Other land use parameters are not standardized to the extent of precise quantification. Some of these parameters are site preparation cost and debris, specialized access construction (barge or rail transit), site aesthetics and surface water contamination during plant construction. Transmission system land use is discussed in a later section of this report.

The baseline plant is considered to have intake screening only to the extent necessary to protect the plant components from damage. The screen face for an intake system is assumed to cost \$240/cfs. (1 ft/sec. approach velocity). Fish damage is assessed on the yearly capitalized value of the fish as shown in the following equation.

$$\text{Fish damage } \left(\frac{\$}{\text{yr}}\right) = \frac{\text{condenser flow}}{\text{river flow}} \times \text{fish value}$$

This is a very crude approximation to a fish damage function.

Air discharges from the baseline plant consist of small quantities of long-lived radioactive gases. This project was instructed not to investigate in detail radioactive aspects of the site. A base figure of 0.238 microcuries/kWh was readily available and was used in the baseline model (Wegmann, 1970). The baseline fossil fueled emissions are modeled using the parameters discussed the non-water impact section of Task-3 Engineering alternatives.

TASK 2 - ACCOUNTING SYSTEMS

The introduction of a thermal power plant can cause major changes in the social, economic and ecological environment of the region. Any attempt to assess these impacts will encounter a maze of information of widely varying accuracy and completeness. In order to define engineering alternatives that can protect the environment, it is necessary to define the appropriate yardsticks to measure the increased protection and to define what needs to be protected.

Approximately one half of this study effort was devoted to the development of economic, social, and ecological accounting systems for use in evaluating the effectiveness of engineering alternatives for the protection of the environment from large, stationary thermal power systems. Historically, the evaluation of power plant development has employed engineering economics which ignored costs or benefits that were not priced in the market place. The introduction of accounting systems that reflect environmental benefits and costs is a difficult task. This project employed the strategy of examining three complementary accounts: engineering economics, ecological, and social. The ultimate goal would be to understand each account completely so transforms could be made from one system to another. Without these transforms three accounts must be used, and costs and benefits identified and quantified.

The results of the research to establish the three accounting systems have been summarized for this report. The socio-economic systems are combines followed by a description of the ecological accounting system.

Task 2: Socio-Economic Accounting

Protection of the environmental resources from the impact of thermal power plant involves the allocation of scarce resources in the form of money, labor, technology, natural resources, and the natural environment. In order to formulate a rationale for resource allocation, some framework for analysis must be established with a common set of units. As part of this research program, Meyer (1972) reveiwed the existing analytical frameworks that could be applied to the socio-economic accounting of thermal power plant siting impacts and sought specific data and methods for this model. The major thrusts of Meyer's efforts were (1) extension of benefit-cost analysis to include social accounting, (2) analysis of the effectiveness of pricing for controlling power plant siting impact, and (3) examination of transmission impacts and fisheries damages as special cases of socio-economic impact of thermal power plants. Each of these efforts are summarized in this report and the analytical framework is presented for model development.

Benefit-Cost Analysis - Economic theory provides a rational framework for allocating scarce resources using the market mechanisms. The problem encountered when this is applied to the benefit-cost analysis of thermal plant siting are well documented but unfortunately the solutions to these problems are lacking. Prices are supposed to reflect the willingness of users to pay and the willingness of suppliers to sell. Unfortunately many of the resources employed in power production are not correctly priced. Water, air, fish and certain other elements of the ecosystem are not owned, and no prices have been established for their use. A dollar value should be established for the use of these resources. If this is infeasible, the cost or benefit to these resources must be quantified in some manner. The suppliers of power have a monopoly in many instances and prices are controlled by government agencies. Thus the price of power may not reflect the willingness to sell in a competitive market. Given these imperfect prices, the user cannot efficiently substitute other resources as economic theory would predict.

The problems of proper pricing of the benefits and costs are only one of several economic problems in the assessment process. The costs of power production are incurred before the benefits, and a time preference must be developed in evaluating power plant development. The literature is rich in the discussion of appropriate interest rates and what should be the accepted opportunity costs used in the construction of power generating facilities. The model must accept interest rate as a variable in order to test the significance of changes.

Similarly, the benefits or damages created as a result of power plant siting are not fully reflected in the price power users are willing to pay. In many cases a project can generate benefits greater than costs on a national basis, yet be unacceptable because those bearing the costs do not receive any benefits. Conversely a vocal group of beneficiaries may argue for a project where costs exceed benefits since they face no costs themselves. Social accounting is a catchall phrase suggesting that all factors be considered in a benefit-cost analysis. An alternative is to conduct the benefit-cost analysis based on available economic data and concurrently conduct a similar analysis quantifying social impact and environmental impacts. In either case it is necessary to identify who pays and who benefits.

Lind (1968) provides an excellent discussion of benefit-cost analysis and cites the major analytical problems of prices, discount rates, opportunity costs, and externalities. Federal water resources programs have strongly influenced benefit-cost analysis and the recent "Proposed Principles and Standards for Planning Water and Related Land Resources" by the Water Resources Council (1971) provides a model that can be used for thermal plant siting evaluation. National, regional, and environmental accounts are proposed to permit groups with various preferences to determine whether an effect is adverse or beneficial. The model developed for this study does not address the regional and national accounts, and is limited to the environmental account.

The analytical framework for this study was formulated to evaluate the engineering alternatives to protect the environment from impacts of thermal plant siting. This approach assumes that more power production would have a net benefit, and the problem is to maximize these benefits by minimizing environmental costs. Clearly, the social costs of providing more power when other opportunities for investment would yield larger returns are ignored, even in the face of lessons learned from investments in water resources development. Discussion of the evaluation of engineering alternatives includes sections dealing with the abortive attempts to address the broader problem of optimum investment in power production.

The economic assessment of engineering alternatives developed in this study focuses on the cost aspects of power generation. Each engineering alternative is identified and the direct costs computed and adjusted to current dollars. Since costs can be sensitive to amortization period, plant life, and discount rates, these parameters are considered to be variables in the analysis. The sensitivity of project cost to these variables can be identified in this model. The factors that enter the economic analysis were established in a review of specific cost proposals for new power generating facilities and the work of Harty et al. (1967) that evaluated 16 sites in the Pacific Northwest. The basic factors used in the model are the cost of the acquisition and preparation of the site, the construction and operation of the power generating units, the transmission facilities, and the environmental protection devices.

Peak Power Pricing to Reduce Demand - A non-engineering alternative to environmental protection is to not provide all the power that is demanded and reduce the potential impacts of new power generating facilities. From an economic view the adjustment of price to reduce the demand for power is a proper and effective alternative if the price of power does not reflect marginal costs and/or during the relevant demand periods, the quantity demanded varies at a particular price. Since the storage of electricity is very expensive (most machines used in the home and factory are not built to store electricity, and people expect instantaneous electric service), demand is met exclusively on-line by production. Utilities are faced with a fluctuating demand schedule, daily and seasonally.

With its supply possibilities the utility must decide how much electricity and at what price to produce at each point in time. Average cost pricing may violate efficiency as well as equity conditions: time-uniform rates ignore the possibility that generation costs vary through time; and uniform rates fail to provide an incentive to substitute low cost (off-peak) for high cost (peak) commodities. If a high cost commodity is under priced, demand for this commodity will exceed supply. When peak power is under priced excessive generating capacity, the use of inefficient, non-price rationing practices or the subsidization of one group of consumers by another group of consumers is the result. Capacity will be under utilized during off-peak periods. And to the extent that off-peak consumers finance fixed costs incurred by peak period consumers, income will be transferred among consumers. A peak load problem exists if, at a specific price, the quantities demanded during two time periods are unequal. The objective is to specify a set of prices which encourage consumers to purchase the optimum quantity of electricity in each period, the optimum quantity being that specified by the equality of incremental cost and price.

Pricing below cost during peak periods really means that some customers pay less than the opportunity cost of those resources used during peak periods, since peak demand is greater than it would be if prices reflected the cost of expanding capacity. If a utitlity does not use peak period pricing procedures, and capacity is sufficient to meet demands upon the system, either extra-price rationing devices are used, or off-peak users are paying a portion of the peak period consumers' capacity costs.

Since utilities do not usually charge prices which vary with time, capacity costs are borne fairly evenly by both peak and off-peak consumers and, to the degree this is true, off-peak consumers subsidize peak consumers. Subsidization of this sort leads to excess generating capacity, as well as under use of that capacity during off-peak periods. Higher peak period prices would restrict peak demand, while lower off-peak prices (equated with marginal cost) would stimulate off-peak demand.

It is this purported misallocation of resources, over investment in capacity, and under use of existing capacity, that is of concern. Subsidiza- is tantamount to saying that there is over investment in system capacity, although there is no present estimate of the magnitude of this over investment.

In the ideal world, with optimal adjustment of plant capacity, the proper prices are those which, during peak periods, are equated with incremental operating and capacity costs or are high enough to ensure that potential demand does not exceed supply, and are equated with marginal operating cost during off-peak periods.

Estimation of new peak period prices was approached from two standpoints. Comparing the average price advertised by BPA of 2.4 mills per kWh ($18.60 per Kilowatt year) with a peak period price of 6.5 mills per kWh allows conclusions to be drawn.

There is the interdependence problem; peak/off-peak electricity are substitutes for each other. The position of the demand for a particular time period will be influenced by the price charged during another demand period. Instituting a price differential will bring into play cross-elasticities which are not now operative. It seems logical that if the cross-elasticity coefficients are positive, raising peak period prices will shift the off-peak demand curve to the right. This being the case, analysis of direct price elasticities will underestimate the effect on a peak period price increase on the quantity purchased.

For households, using an elasticity of -.4, the new peak period price might be expected to reduce peak period consumption by 50 percent. This means that 10 years after the price change, household consumption will be 50 percent less than presently anticipated. For the primary metals industry, into which category the aluminum industry falls, the quantity response is 230 percent. The magnitude of the adjustments is dependent upon industry's ability to shift peak consumption to off-peak periods.

These numbers must be used with extreme caution. They suggest that if peak period prices were adjusted, the additions to system capacity presently envisioned might exceed what in fact is necessary. If peak period pricing sufficiently reduced peak period demand, allowing the postponement of additional generation and transmission capacity, the economy or savings would be the annual fixed interest charges times the years delayed. Annual fixed interest charges are estimated as $19,100,000 for a hypothetical 1,000 MW plant generation plant and $5,016,000 for the related transmission facilities. Thus, $24,116,000 of capital resources can be used elsewhere if construction is postponed for a year.

By applying the household elasticity to <u>all</u> electric consumption in the Pacific Northwest, it is possible to gain a notion of the possible savings. If all anticipated consumption were reduced by 30 percent during the period 1970 to the end of 1980 the savings can be estimated, assuming that the reduction is linear over the 10 year period. Furthermore, it is necessary to assume that the fixed costs, $24,350,000 per year, are realistic, and that the mix of generation capacity and transmission capacity will be constant.

In its 1969 Annual Report BPA indicates that over 11 million kilowatts of generation capacity will be required during the period 1970 to 1980 in the Pacific Northwest. A 30 percent reduction in anticipated growth will reduce the additions to capacity by 3.3 million kilowatts. At the end of 1973, the end of 1976 and the end of 1979 the proposed addition of a 1,000 megawatt nuclear power plant would not be necessary if prices were raised. By applying an annuity factor for the seven, four and one year time periods to the $24,350,000, at the end of 1970 the present value of the potential gross savings amounts to over 150 million dollars.

There are situations in which peak period pricing reduced peak period demand. The French reduced their national peak by 5 percent after instituting a pricing schedule which more precisely reflected the costs of production; the reduction amounted to the equivalent of approximately 50 percent of the load growth anticipated during that first year. Turvey (1968) cites an example in New Zealand in which those customers who have their water heaters switched off during peak daily periods are sold electricity at approximately 1/3 the rate of those who use peak energy. This strategy reduced peak load demand by 20 percent.

For multiple-dial meters the French use ripple control equipment; high frequency electricity is used to switch meters. It is also possible to use clocks to regulate multiple-dial meters, although clocks which are electrically powered are not without their problems. Outages desynchronize the clocks with the daily or weekly load cycle. However, clocks can be powered by other means. In the United States demand controllers have been used to limit loads.

It is possible that residential customers will find metering and billing costs too high for even a two-dial meter, in which case there are other possibilities. Higher winter costs could be used as a rationale for discouraging electric home and water heaters. Or, electric home and water heaters can, as they are in England, be designed to store heat energy, and then be switched off during peak demand periods. Turvey (1968) cites examples of hot water heaters with a six-hour supply of hot water.

Obviously, any effort to promote peak period demand is not rational; and it seems likely that there are more marginal cost pricing possibilities than have been or are in use.

With potential gross savings of 150 million dollars, and given the examples of capital cost savings in other countries, peak period pricing obviously deserves further investigation. If it is decided that the anticipated additional costs of metering, billing, administration and the consumers' additional equipment costs do not exceed the potential gross savings, there are net benefits to be captured. If the costs of household appliance modification or industrial modification do exceed the potential savings, the case for marginal cost, peak period pricing is not as strong. There may be grounds for peak period pricing if it is no longer acceptable to transfer income from off-peak period to peak period consumers.

Lastly, it may be argued that a marginal cost pricing schedule will reduce peak period demand growth sufficiently to allow for a greater margin of reserve capacity or more time to plan for the proper siting of nuclear power plants.

In order to accommodate peak pricing evaluation, costs for all power generation components of a regional system must be available. Thus the peak pricing issue is not of concern in the siting of a specific plant as much as it is in the dynamic analysis of a series of site selections. The dynamic assessment model is constructed to integrate the results of individual site assessment and test the impact of alternative time sequences of power plant sitings.

<u>Methods to Include Externalities</u> - Faced with the choice to quantify externalities in dollar terms or maintain separate accounts to permit comparison of engineering alternatives, Meyer elected to examine specific externalities related to fishery damage from power plant cooling and transmission of power and develop a modeling methodology. While these studies identified methods to estimate the rent from the use of water or land and introduce some social accounting into the analysis, it is not a complete social accounting.

The market place fails to efficiently allocate common property fishery resources for reasons very similar to the market's failure to allocate external costs; fishery property rights are not defined, transferable or enforceable. The fluidity of the product, the fishery, prohibits the establishment of well-defined property rights.

Without well-defined property rights, labor and capital can freely enter the fishery. When the price (not the cost) of entrance is zero, the fishery will be exploited as long as it yields positive rents. As long as entry is not restricted, the contribution of the fishery, rent, will be viewed as excess profits and additional capital and labor will be attracted to the industry. Entry continues until rents are dissipated, and the net economic contribution of the fishery is zero. The relevant consideration, rent, is the value of the fishery optimally regulated.

Royce et al. (1963) feel that 50 percent of the gross value of the Puget Sound salmon fishery is potential rent. By eliminating redundant labor and capital and allowing the remaining gear to fish a full week, instead of two days per week, the State of Washington may capture the fishery rent. If rules enforcing the inefficient use of capital are eliminated, net rent can be expected to exceed 50 percent of the gross fishery value.

The commercial Columbia River catch averages approximately $6.7 million a year, 75 percent of which is potential rent (Crutchfield and Pontecorvo (1969)).

For the Sacramento River, Fry (1962) has estimated potential net economic yields to be 90 percent of the gross value of the fishery. Mathews and Wendler (1968) have made similar estimates for the potential yield from the 1965 Columbia River fishery for the spring and fall chinook runs.

For the sport fishery, the economic value is not the fish, but the fishing experience; although catching the fish is intrinsically involved, the service is the fishing activity.

Estimating net yields from a sport fishery is very difficult. Since only a nominal or zero price is charged, there is little price information about how intensely fishermen like to fish. For the commercial catch, some have used the price of commercially caught fish. Although gross annual sport fishing expenditures may be important from a local standpoint, they are not pertinent in a national assessment.

Economists have resorted to other methods of net yield estimation, since the traditional indicators are absent. An Oregon study, published by Brown, Singh and Castle (1964), and other studies have used distance-cost models for estimating recreational values. The estimated minimum net value for all Oregon salmon and steelhead sport fisheries in 1962 was $2.5 million for about 282,000 fish caught on 1,100,000 angler days.

Brown and Mathews (1970) have used the questionnaire approach. Although, like the other procedures, there are disadvantages, this method requires that sport fishermen establish a minimum annual price for which they would be willing to sell their right to salmon fish. The authors recommend using a minimum net value of $28 per salt-water sport fishing day in Puget Sound and along the Washington coast. This is an estimate of how much sport fishermen are willing to pay for the opportunity to fish. The authors also found that net benefits increase as catch per day rises.

If, as Mathews and Brown show, there is a positive relationship between net value and catch per trip, and their sport catch were increased, net rents would increase by $28 per angler-day and decrease by the amount of the commercial fishery rent or 50 percent of the gross value. It is assumed that the possibility of doing so would not be so great as to alter the incremental values involved.

Crutchfield and MacFarlane (1968) estimate that if similar restrictions were placed on the halibut fishery, the net rents accruing to society would be in the range of 40 to 50 percent of the gross value of the annual catch.

These data indicate that if the impact of a power plant on fishes can be determined in terms of the increase or decrease in the annual catch, some estimate of the economic value of that change in catch can be made. In the case of fishery that are damaged by the release of heat or chemicals, the full cost of these damages should be charged to the cost of producing power. Conversely, if fish stocks are increased the benefit should be credited to the power plant. When the fishery affected is privately owned, such as for oyster or fish farming, the estimate of benefits or costs created by a power plant could be directly obtained from the anticipated changes in net earnings of the firm in question.

Based on these findings, the model has been developed to estimate the changes in fisheries in terms of diversity of fishes, and value of the fishery, as a result of heat and chemical discharges, and physical losses from intake structures.

Transmission lines were evaluated for three externalities: visual impact; erosion, sedimentation and water quality changes; and non-payment for land use changes.

Since BPA has modified some of its transmission practices, avoiding scenic areas and adopting its own environmental standards, it is logical to argue that a portion of average transmission costs are the result of efforts to minimize transmission externalities. The magnitude involved cannot be defined. Whether BPA activities are optimal has not been shown.

Personal communication with BPA representatives is the source of the wheeling formulas (cost to involved in delivering power).

$1.32/kW-year - Plant west of the Cascades to the major load center
$2.33/kW-year - Hanford
$4.37/kW-year - Libby
$ .81/kW-year + $.01/mile kW-year - general formula, subject to annual negotiation

If economies of scale exist for the transmission of electricity and this service is financed so that total revenue equals or exceeds total cost, then the wheeling costs could be viewed as an upper limit to incremental transmission costs. BPA indicates that transmission of power is self-supporting; i.e. revenues including interest charges, exceed costs.

The wheeling formula costs were calculated on the basis of financial costs, not economic costs. Since interest rates influence costs, improper interest rates results in erroneous costs. Through fiscal year 1963 the rate was 2-1/2 percent; subsequently, the rate has gradually risen to 6-3/8 percent.

As mentioned earlier, the choice of interest rate is crucial and under-estimation of interest rate results in an underestimation of the opportunity cost of capital. This is especially important in the case of transmission cost since capital costs are a major fraction of the total costs. For a double circuit, 500-KV, 200-mile, 1000 MWe capacity line, using an interest rate of 7 percent, an economic life of 45 years, BPA average system line losses of 4-1/2 percent valued at $18.60 per kW-year, 15 percent overhead charges, and the construction, terminal facility and operation and maintenance costs presented in the section on peak period pricing yields an annual, incremental transmission cost of approximately $5,700,000. For 200 miles and 1,000 MWe, the general wheeling formula generates a figure of about $2,810,000. The difference between $5,700,000 and $2,810,000 is caused by an inappropriate interest rate, although the interest rate used by BPA is specified by law.

Based on this comparison, transmission costs should not be based on wheeling formulas developed by utilities unless appropriate discount rates have been used.

The visual costs that property owners adjacent to transmission line right-of-way are willing to pay to diminish the visual impact are less than the costs of transmission practice modification. To appreciably increase transmission distance or to underground wires may increase costs in excess of the amount people are willing to pay to reduce external visual effects. The apparent lack of property value depreciation due to transmission line proximity lends support to this position. In urban areas, particularly adjacent to high value residential areas or heavily used scenic areas, the cost of alternative routing or undergrounding may, however, be less than the external cost.

It also seems likely that the visual costs borne by the traveling public are directly related to the frequency of encountering towers. And if, as is possible, the public is willing to forego something in order to reduce visual costs, there are options which allow the planner to arrange the roadside view in a cost-minimizing manner. These options include undergrounding, alternative routing and the adoption of visual-impact-minimizing techniques.

Since the external costs involved are difficult or impossible to quantify, the values involved can only be imputed by alternate routing, and consequently lengthening the transmission distance, undergrounding or including the costs of constructing aesthetically superior transmission lines. Displaying the costs of alternative strategies will assist the decision maker to select the desirable alternative.

Presently, in central business districts, underground transmission lines are often the least-cost alternative; this is evidenced by the existence of underground lines, although utility decisions may be influenced by visual considerations. The Federal Power Commission (1966) indicates that underground transmission costs exceed overhead transmission costs by from 10 to 40 times in rural areas and from 1 to 20 times in urban-suburban areas. Using an escalation factor of 10, applied to the above baseline costs, yields an average annual cost of $57,000,000. Assuming there are no visual costs associated with underground lines, this figure represents one of the variants of the transmission cost alternatives. Another possibility for eliminating visual costs is to locate the power plant near the load center.

If, as was previously argued, the proper goal is environmental cost minimization, undergrounding may be optimal in particular localities. For instance, if, to avoid residential areas or scenic areas, 20 miles of undergrounding is being considered, the additional cost of $523,000 is the relevant value. The decision making body would then decide if the visual values exceeded the additional $523,000.

The estimation of social costs related to erosion, sedimentation and water quality changes caused by land use for power transmission can be obtained from rents and costs of right-of-way management practices. Engineering alternatives such as paving of roads, use of aerial transport to install facilities, and improved methods of maintaining vegetation can preserve fish, wildlife and water quality. When the land is privately owned, the rent will reflect costs to satisfy environmental criteria. However, if rent is not collected or if federal agencies do not require land management to protect the environment in transmission rights-of-way, these costs will be difficult to estimate and internalize.

Transmission and right-of-way management strategies which minimize external costs are obviously desirable, but in normal situations it does not seem likely that internalization of external costs will appreciably alter the location or length of transmission lines. For example, if a change in procedures caused right-of-way acquisition and management process costs to increase from \$19,000 to \$36,000 per mile, a highly unlikely increase, annual transmission costs for the example used above would increase by less than \$300,000 a year. Considering the large incremental cost of altering plant location it is very unlikely that internalization of these costs will appreciably change any plant's location. However, the small magnitude involved should not be used as a rationale for ignoring the diseconomy.

Social Accounting - This research has failed to produce any significant improvement in the formulation of a social account for assessing the environmental impact of thermal power plant siting. The internalization of externalities, the estimation of rents, and the selection of proper discount rates were existing concepts prior to this study. Peak period pricing is suggested to reduce the demand for power and internalize specific benefits and costs. This allows the market mechanism to allocate costs to power consumers, but does not contribute to the internalization of costs associated with environmental degradation. The model developed in this research does not reflect any other social factor.

An exploratory attempt to develop a single surrogate for social impact did not yield an acceptable solution to this problem. The most promising surrogate appears to be lead time between an identified need for power and the ability to satisfy this added demand.

Lead time costs are described by several utilities as one of the more important considerations in siting a nuclear power plant. It has been argued elsewhere that because proper consideration has not been given to the negative external effects of power generation and distribution, the public responds by impeding or, in some cases, completely blocking prospective power plants. Examples are numerous, and this occurs in spite of the fact that the utilities conduct extensive educational and advertising programs to promote public acceptance. To properly analyze public acceptance or opposition and its effect upon lead time requires extensive research, since with the comparison of two locational alternatives all other things will inevitably not be equal.

Seattle City Light's representatives have indicated that it takes approximately nine years to plan and have a nuclear power plant in operation. Felton (1971) indirectly states that the total time involved is a little over eight years. These figures seem appropriate only after preliminary studies have narrowed down the range of locational alternatives. Prior to the nine-year period resources are allocated to load forecasting, planning and preliminary site investigations. Facilities established during earlier power development may be the controlling factor on current efforts.

Felton (1971) analyzed the time period necessary to receive a construction permit. Since 1967 construction permit applications have required progressively more time. The average time was 10.5 months in 1967, 13.25 months in 1968, 19 months in 1969 and 18.25 months in 1970. Most of the increase took place prior to the final Advisory Council on Reactor Safequard's review. For 1971 Felton calculated, excluding anomalies, that the 10 plants which received construction permits required an average time of 20.5 months. These data bias any predictions since 21 applications were filed; the numerical time applies only to the 10 which received permits.

Construction and delivery times have also increased. Delivery time from contract to operation for 14 plants in operation in 1968, ranged from four to 10 years with a mean of six years (Nuclear News, January, 1970). Larger numbers of orders in 1966 and 1967 led to delays in plant delivery. Only two of the 13 nuclear power plants scheduled for commercial operation in 1969 were in operation on schedule.

One investigation into the causes of delays, Hogerton (1970), of 70 nuclear power plants for which construction permit application had been submitted concluded that delays averaged 4.5 months, ranging from one to 13 months. Causes of delay are listed in order of importance: labor, licensing, delivery, public opposition, construction problems and scheduling problems. Hogerton also states that utilities are now allowing more construction time, approximately 5.3 years.

Until very recently, public opposition has been most active prior to initiation of construction. It has forced the utilities to invest more resources in planning and ecological research. It also has produced significant changes in the licensing requirements at both the state and federal level. The recent Calvert Cliffs decision, U. S. Court of Appeals, Washington, D. C., required that 110 proposed reactors, 46 of which have construction permits and could be modified, must be subject to environmental reviews. The court held that the A.E.C. was not meeting its responsibilities for implementation of the National Environmental Policy Act, and the A.E.C. must, at all stages of licensing, evaluate environmental values.

After analyzing the proposed Bell Station on Lake Cayuga, Nelkin (1971) has argued for coordinated regulatory activities, and greater flexibility on the part of the utilities. The Bell Station was postponed approximately 1-3/4 years after formal announcement of plans. The controversy was predominantly centered about possible thermal effects. New York State Electric and Gas Corporation learned that the burden of proof rested with them; and that regardless of the misinformation about their plans, the public's tastes and perception of property-use rights had changed sufficiently to stop the plant.

Jopling and Gage (1971) considered five case studies. identifying the salient issues for each siting controversy. The authors recommend public consultation by the utilities, incorporation of public opinion into the decision process and more public hearings.

Additionally, proposals have been made for changes in the A.E.C.'s reactor licensing rules. These proposals have been made by an ad hoc group of lawyers from the Atomic Energy Industrial Forum and the A.E.C. If enacted, the changes are expected to accelerate methods of handling license applications.

At the state level new regulations have emerged also. To assure more certainty in the siting of thermal power plants some states have created comprehensive site evaluation agencies. Of note is the Washington State Thermal Power Plant Siting Council and the New York State Atomic and Space Development Authority.

Designed to protect the public and provide the utilities with a one-stop state evaluation, these agencies can be expected to reduce the red tape associated with plant siting and provide the public with the feeling that all issues are being evaluated.

The New York Agency is authorized to issue bonds to acquire and develop thermal power plant sites for resale or lease to utilities. The Washington Council is composed of the pertinent state agencies, representatives of local governments and an independent consultant to represent the public.

The available information and the experience in power plant siting of the proposing and opposing groups will be major factors in the time required to win approval for plant construction. Currently the time required reflects the delays caused by lack of proper forums for debate and decision-making, as well as time required to resolve critical issues. In the future the former delays will be minimized since one-stop approval agencies are being created and formats for impact statements are becoming standardized. The delay time will reflect more closely the concern over environmental impacts and the willingness of society to accept or reject these. It may be possible then to identify delay time as the surrogate for social cost. Unfortunately insufficient empirical data were available to develop a function that could be incorporated in the model.

Task 2: Ecological Accounting

In response to the predicted increase in use of natural waters for cooling purposes, several comprehensive literature reviews have been compiled to provide quick reference to effects of changes in water temperature upon aquatic organisms (Brett, 1956; Wurtz and Renn, 1965; Altman and Dittmer, 1966; Welch and Wojtolik, 1968; Jensen et al., 1969; Parker and Krenkel, 1969; deSylva, 1969; Hawkes, 1969; Coutant, 1968, 1969, 1970, 1971; Marble and Mowell, 1971). Despite this concentration of literature there has been a great reluctance by biologists to predict the response of an aquatic system to increased water temperatures. One reason, and perhaps the basic one, is that many of the multitude of interactions within an aquatic community are unknown and the understanding of the known is hazy at best. Thus, it may seem unrealistic to predict the consequences of altering one basic environmental parameter.

Other reasons for reluctance stem from the fact that the great majority of the data available are from research programs investigating the effects of temperature elevation on single test organisms. There is a paucity of studies at the population or community level. Also, much of the research has been performed in laboratories, and there is hesistance to extrapolate laboratory results to field situations.

However, in planning the use of a waterway for cooling water discharge, it is essential to be able to determine the amount of heated water that can be safely introduced or to be able to make some estimation of the consequences of altering the natural temperature regime. The authors recognize the immediate need for studies designed especially for the purpose of estimating the response of aquatic communities to elevated temperature, but feel in the absence of these data there is information enough to at least be able to set forth guidelines and highlight possible problems that may be expected to result from increased water temperature.

Even though only a first approximation, such guidelines would be very useful in siting power plants if properly applied and qualified.

This study has been made as a guide to the possible effects of increased water temperature on both freshwater and marine aquatic systems with special consideration to fishes as the principal indicator organisms.

Freshwater Fish - Data on the thermal requirements for 85 species of freshwater fish are presented in tabular form by Bush *et al.* (1972). Although the data are the result of numerous studies using a variety of experimental techniques, they provide a good approximation of the thermal tolerance limit and preferred temperature for a significant sample of the important fish species.

By tabulating the typical fish species inhabiting a river system and compiling the available data on thermal requirements for the species, predictions were made on which fish species would be adversely affected by increased water temperature. Such predictions are presented in this manuscript for six representative river systems in the U. S. The predictions are based upon three assumptions: (1) that a fish species would be lost from an area, either by death or emigration, if the water temperature was raised to the highest lethal limit for that species reported in the literature, (2) that a fish would be subjected to suboptimal conditions that would have a detrimental effect on its activity, growth and survival or would avoid the reach of the river if the water temperature in that reach was raised above the preferred temperature of the species (the highest reported in the literature at the highest acclimation temperature) and (3) that a change in the temperature regime that did not raise the water temperature above a fish's preferred temperature would not have an adverse effect on that species.

The estimated community response of freshwater and anadromous fish species to elevated temperature for six representative river systems is presented in Tables 5 through 10. The river systems chosen were the Columbia River, Sacramento River, Upper Mississippi River, Lower Mississippi River, Tennessee River and the Delaware River. No one reach of each river will contain all the fish species indicated for the river system. Thus, in using these tables, the reader must be aware of the fish species in the reach of the river concerned and must adjust for fish species that are predicted to be harmed but are not present. Similarly, the user must acknowledge that species not listed in the tables may indeed occur in the reach of the river concerned, and these should be considered in the predictions of community response. Estimation of the effect on any fish species not listed for the river systems (Tables 5 - 10) can be derived from the original data compiled for that species, (Bush, et al. (1971)). If compiled data for that species are not available, compiled data from fish of the same family or genus could be used as a best estimate of the response of the fish concerned.

The predictions in Tables 5 - 10 are based on preferred and lethal temperature data for adult and juvenile fish. They exclude the effect of increased water temperature on spawning and egg hatching success. Where specific data for a species were not available, data from closely related species (species from the same genus or family) were used.

A fish species is assumed to be within its preferred temperature range if the given water temperature (or mixed river temperature) is lower than the highest reported preferred temperature determined at the highest acclimation temperature for the fish. The suboptimal temperature range is the range above which a fish prefers but below its lethal limit. In this temperature range the fish is considered stressed and an adverse effect on its activity, growth and survival is predicted. Exposures to sublethal temperatures over long periods of time can be just as harmful as lethal temperatures and may cause the elimination or drastic reduction in the population size of stressed species even to the eventual elimination of species (Tarzwell, 1970). Except for the anadromous fish, the

Table 5. Predicted Effect of Increasing Water Temperature on the Fish Community of the Columbia River(1)

°C	°F	% of species within preferred temp. range	% of species in suboptimal temperature conditions (2)	% of species expected to be lost from the system	species expected to be lost from the system
8	46.4	100	0	0	
10	50.0	95	5	0	
12	53.6	93	7	0	
14	57.2	88	12	0	
16	60.8	60	40	0	
18	64.4	54	44	2	Columbia River smelt
20	68.0	51	44	5	freshwater smelt
22	71.6	28	65	7	Puget Sound smelt
24	75.2	26	48	26	sockeye salmon, chinook salmon, chum salmon, pink salmon, coho salmon, Dolly Varden, Rocky Mt. whitefish, chiselmouth jack
26	78.8	16	44	40	brook trout, Aleutian sculpin, prickly sculpin, Columbia sculpin, sculpin, starry flounder
28	82.4	9	49	42	lake trout
30	86.0	9	26	65	white sturgeon, green sturgeon, American shad, cutthroat trout, brown trout, longnose sucker, tuichub, squawfish
32	89.6	7	12	81	rainbow trout, coarsescale sucker, yellow perch, fresh-water burbot, Columbia finescale sucker, chiselmouth, longnose dace, western speckled dace, Columbia R. chub
34	93.2	0	14	86	redside shiner, threespine stickleback
36	96.8	0	7	93	tadpole madtom, smallmouth bass, black crappie
38	100.4	0	0	100	carp, largemouth bass, bluegill

(1) based on preferred and lethal temperature data for adult and juvenile fish. Where specific data for a species were unavailable, data from closely related species were used.

(2) the temperature range above the preferred temperature and below the lethal temperature.

Table 6. Predicted Effect of Increasing Water Temperature on the Fish Community of the Sacramento River[1]

°C	°F	% of species within preferred temp. range	% of species in suboptimal temperature conditions [2]	% of species expected to be lost from the system	species expected to be lost from the system
8	46.4	100	0	0	
10	50.0	97	3	0	
12	53.6	95	5	0	
14	57.2	92	8	0	
16	60.8	72	28	0	
18	64.4	72	28	0	
20	68.0	69	28	3	freshwater smelt
22	71.6	59	36	5	Sacramento smelt
24	75.2	38	44	18	pink salmon, chum salmon, coho salmon, sockeye salmon, chinook salmon
26	78.8	33	41	26	Aleutian sculpin, prickly sculpin, rough sculpin
28	82.4	23	51	26	
30	86.0	15	49	36	white sturgeon, green sturgeon, brown trout, Sacramento squawfish
32	89.6	8	46	46	rainbow trout, California sucker, Sacramento smallscale sucker, stripped bass
34	93.2	0	33	67	hardhead, Sacramento blackfish, splittail, hitch, western roach, tuichub, thicktail chub, threespine stickleback
36	96.8	0	13	87	white catfish, channel catfish, brown bullhead, black bullhead, smallmouth bass, black crappie, Sacramento perch, green sunfish
38	100.4	0	0	100	threadfin shad, carp, largemouth bass, spotted bass, bluegill

(1) based on preferred and lethal temperature data for adult and juvenile fish. Where specific data for a species were unavailable, data from closely related species were used.

(2) the temperature range above the preferred temperature and below the lethal temperature

Table 7. Predicted Effect of Increasing Water Temperature on the Fish Community of the Upper Mississippi River[1]

°C	°F	% of species within preferred temp. range	% of species in suboptimal temperature conditions[2]	% of species expected to be lost from the system	species expected to be lost from the system
18	64.4	100	0	0	
20	68.0	98	2	0	
22	71.6	75	25	0	
24	75.2	61	39	0	
26	78.8	49	51	0	
28	82.4	18	82	0	
30	86.0	14	79	7	shovelnose sturgeon, pallid sturgeon, lake sturgeon, emerald shiner
32	89.6	7	49	44	blue sucker, largemouth buffalofish, smallmouth buffalofish, quillback carpsucker, rabbitmouth sucker, silver redhorse, golden redhorse, greater redhorse, blacknose dace, longnose dace, creek chub, white bass, yellow bass, yellow perch, sauger, walleye, log perch, slenderhead darter, greenside darter, Johnny darter, banded darter
34	93.2	2	35	63	stoneroller, golden shiner, redside dace, fathead minnow, bluntnose minnow, bullhead minnow, redfin shiner, mimic shiner, blackchin shiner, ironcolor shiner, spottail shiner
36	96.8	0	12	88	northern pike, blue catfish, channel catfish, flathead catfish, yellow bullhead, brown bullhead, black bullhead, stonecat, madtom, smallmouth bass, black crappie, white crappie, warmouth, green sunfish
38	100.4	0	2	98	gizzard shad, carp, largemouth bass, bluegill, orangespotted sunfish, pumpkinseed
40	104.0	0	0	100	banded killifish

(1) based on preferred and lethal temperature data for adult and juvenile fish. Where specific data for a species were unavailable, data from closely related species were used.

(2) the temperature range above the preferred temperature and below the lethal temperature.

Table 8. Predicted Effect of Increasing Water Temperature on the Fish Community of the Lower Mississippi River[1]

°C	°F	% of species within preferred temp. range	% of species in suboptimal temperature conditions (2)	% of species expected to be lost from the system	species expected to be lost from the system
18	64.4	100	0	0	
20	68.0	98	2	0	
22	71.6	78	22	0	
24	75.2	64	36	0	
26	78.8	50	50	0	
28	82.4	26	74	0	
30	86.0	22	74	4	shovelnose sturgeon, emerald shiner
32	89.6	10	54	36	river herring, blue sucker, largemouth buffalofish, smallmouth buffalofish, quillback carpsucker, carpsucker, Alabama chubsucker, rabbitmouth sucker, black redhorse, yellow bass, white bass, Arkansas sand darter, yellow perch, log perch, dusky darter, goldstripe darter
34	93.2	4	38	58	stoneroller, golden shiner, fathead minnow, pugnose minnow, silvery minnow, cypress minnow, blacktail shiner, flagfin shiner, common shiner, blackfin shiner, river shiner
36	96.8	0	18	82	redfin pickerel, blue catfish, channel catfish, brown bullhead, black bullhead, flathead catfish, flier, black crappie, rockbass, warmouth, green sunfish
38	100.4	0	4	96	gizzard shad, carp, largemouth bass, spotted bass, spotted sunfish, bluegill, redear sunfish
40	104.0	0	0	100	blackstripe topminnow, blackspotted topminnow

(1) based on preferred and lethal temperature data for adult and juvenile fish. Where specific data for a species were unavailable, data from closely related species were used.

(2) the temperature range above the preferred temperature and below the lethal temperature.

Table 9. Predicted Effect of Increasing Water Temperature on the Fish Community of the Tennessee River(1)

°C	°F	% of species within preferred temp. range	% of species in suboptimal temperature conditions (2)	% of species expected to be lost from the system	species expected to be lost from the system
12	53.6	100	0	0	
14	57.2	99	1	0	
16	60.8	99	1	0	
18	64.4	97	3	0	
20	68.0	96	4	0	
22	71.6	72	28	0	
24	75.2	61	39	0	
26	78.8	51	48	1	brook trout
28	82.4	21	78	1	
30	86.0	15	81	4	shovelnose sturgeon, brown trout
32	89.6	6	43	51	skipjack herring, rainbow trout, blue sucker, smallmouth buffalofish, largemouth buffalofish, highfin carpsucker, carpsucker, spotted sucker, hogsucker, silver redhorse, shorthead redhorse, river redhorse, black redhorse, golden redhorse, white sucker, longnose dace, white bass, walleye, sauger, log perch, gilt darter, dusky darter speck darter, greenside darter, Tennessee snubnose darter, Johnny darter, goldstripe darter, banded darter, redline darter, spottail darter, Cumberland fantail darter
34	93.2	1	30	69	stoneroller, golden shiner, bluntnose minnow, river chub, blotched chub, spotfin chub, bigeye chub, common shiner, popeye shiner, mimic shiner, Tennessee shiner, silver shiner
36	96.8	0	12	88	muskellunge, blue catfish, channel catfish, flathead catfish, brown bullhead, stonecat, smallmouth bass, black crappie, white crappie, warmouth, longear sunfish, orangespotted sunfish, redear sunfish
38	100.4	0	1	99	gizzard shad, threadfin shad, carp, largemouth bass, spotted bass, rockbass, bluegill
40	104.0	0	0	100	white streaked killifish

(1) based on preferred and lethal temperature data for adult and juvenile fish. Where specific data for a species were unavailable, data from closely related species were used.

(2) the temperature range above the preferred temperature and below the lethal temperature.

Table 10. Predicted Effect of Increasing Water Temperature on the Fish Community of the Delaware River(1)

°C	°F	% of species within preferred temp. range	% of species in suboptimal temperature conditions (2)	% of species expected to be lost from the system	species expected to be lost from the system
12	53.6	100	0	0	
14	57.2	100	0	0	
16	60.8	100	0	0	
18	64.4	96	4	0	
20	68.0	82	18	0	
22	71.6	72	28	0	
24	75.2	52	48	0	
26	78.8	36	62	0	smelt
28	82.4	26	70	4	alewife
30	86.0	20	66	14	tomcod, Atlantic sturgeon, shortnose sturgeon, American shad, Atlantic salmon
32	89.6	8	24	22	alewife, hickory shad, common sucker, spotted sucker, chubsucker, eastern redhorse, hogsucker, blacknose dace, pearl dace, silverline shiner, striped bass, white perch, yellow perch, blackside darter, Johnny darter, creek chub
34	93.2	2	32	66	fallfish, golden shiner, fathead minnow, bluntnose minnow, northern chub, satinfin shiner, bridled shiner, swallowtail shiner, silvery minnow, silverfin shiner, threespine stickleback
36	96.8	0	12	88	chain pickerel, redfin pickerel, white catfish, yellow bullhead, brown bullhead, madtom, banded sunfish, bluespotted sunfish, rockbass, yellowbelly sunfish, smallmouth bass
38	100.4	0	2	98	gizzard shad, carp, largemouth bass, bluegill, pumpkinseed
40	104.0	0	0	100	variegated cyprinodon

(1) based on preferred and lethal temperature data for adult and juvenile fish. Where specific data for a species were unavailable, data from closely related species were used.

(2) the temperature range above the preferred temperature and below the lethal temperature.

temperature at which a species is expected to be lost from the system was derived from the highest recorded lethal limit reported in the literature. During their migration through a reach of a river with elevated temperatures, anadromous fish would not have time for full acclimation to the heated waters. Therefore the temperature at which an anadromous fish was estimated to be lost from the system was derived from lethal limits determined at intermediate acclimation temperatures.

The tables of predictions of alterations in fish communities in a river are meant to set forth guidelines and highlight possible problems that are expected to result from increased water temperature. The accuracy of these predictions must be qualified not only because of the varied techniques used by researchers who produced the data upon which the predictions are based, but also because they do not consider the response of a fish species to the numerous other environmental variables that interact with a temperature increase to affect the species.

It is impossible at this time to integrate all the biotic and abiotic environmental variables that change with increased water temperature into a comprehensive table to predict effects on fish. If possible, such integration would undoubtedly indicate a loss of more native fish species from a river system than would result from consideration of temperature alone. Recognizing the need for such qualification and more detailed studies at most sites, these predictions will be useful as guidelines in predicting the consequences from altering the natural temperature regime in a section of a river. Their purpose is to aid the initial evaluation of thermal power plant siting and cooling water discharges. In no way do these preliminary predictions replace the need for extensive studies to define thermal environmental impacts at the selected site.

Freshwater Invertebrates - The data compiled from the literature search for lethal temperature limits for freshwater invertebrates are reported by Bush *et al*. (1972). Temperature tolerances have been determined for only a small fraction of the total number of freshwater invertebrate species. There is estimated to be about 8,500 described species of freshwater invertebrates excluding protozoa and parasitic classes (Pennak, 1953). The relatively small number (94) of species for which data on thermal requirements are available precludes community response estimations similar to those given for freshwater fish. However, there seems to be evidence that in protecting fish, the invertebrate fauna will also be protected. According to Mount (1969):

> "There is a substantial amount of evidence that fishes frequently are more sensitive to elevated temperatures than are most of the food chain organisms. This is not to say that some varieties of invertebrates or phytoplankton are not more sensitive than fishes, but it does imply that, under increased temperature, sufficient food organisms will be present, though they may be of different kinds, to support the harvested crop."

Further there does not seem to be an example in the literature of a heated discharge destroying the bottom fauna to the extent that the fish population was adversely affected by lack of food organisms. Parker and Krenkel (1969) report that the heat tolerance of most macroscopic invertebrates for which data on lethal limits reported by Bush et al. (1972) are representative of the tolerance range of freshwater invertebrates in general, then Figure 6 supports the thesis that protection of the fish will in general result in the protection of most invertebrate fauna or at least an adequate fish food supply. Figure 6 gives the mean lethal temperature for each freshwater fish and invertebrate respectively for which data were found. The figure suggests that when nearly all fish species are protected from heat water discharges, the invertebrate organisms should also be protected. At least, as Mount (1969) suggested, there would be food organisms present. In an extreme case, Figure 6 indicates that invertebrate species, many of which are fish food items, will still exist after all fish are killed by heat.

Because of the regional variation in the composition of invertebrate fauna, results from the few studies reported in the literature may not be indica-

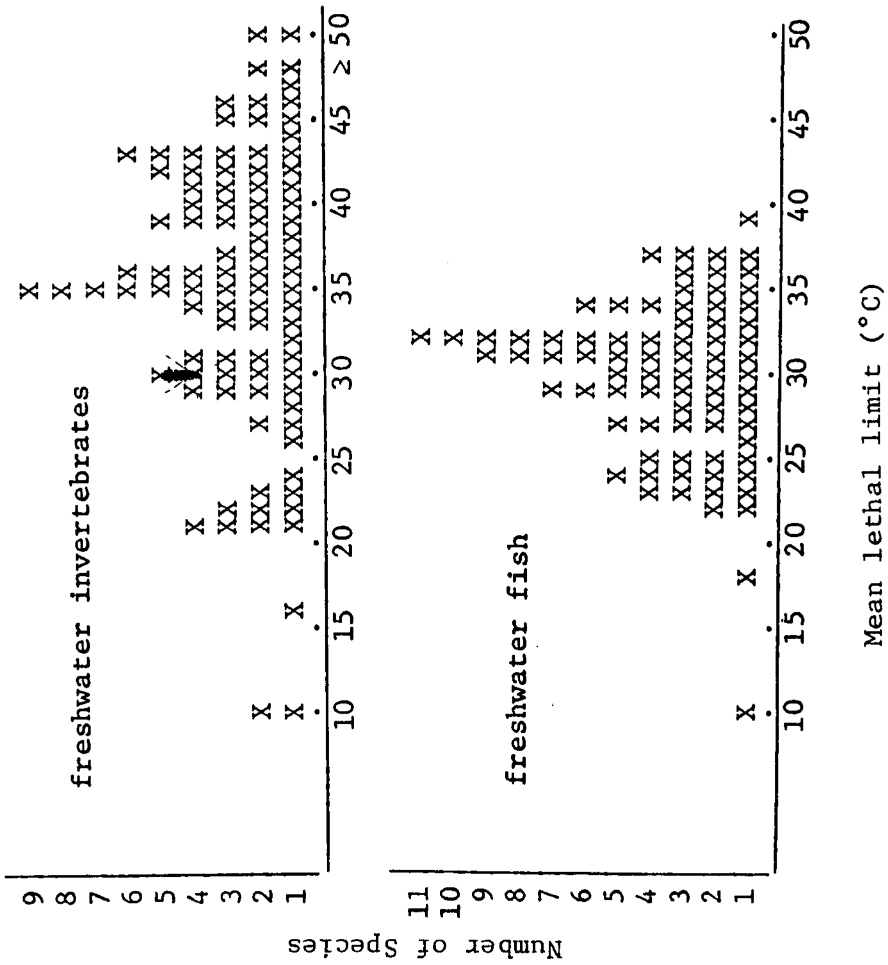


Figure 6. Number of Species and Mean Lethal Limit for Freshwater Fishes and Invertebrates

tive of the temperature tolerance for an invertebrate community in general and, therefore, are not a sound basis for guidelines. However, if indeed the adequate protection of fish species results in like protection of the principal invertebrate fauna, at least to the extent that there will be preservation of fish food organisms to support the fish population, then the use of the tables on the estimated effect of elevated temperature on freshwater fish communities will suffice as a guideline for both the protection of fishes and invertebrates.

Freshwater Algae - The composition of an algal community in a river may change with variations in environmental conditions as the competitive advantage of some forms is changed. Because of the acute competition among algal species for space, nutrients, light, etc., conditions need not reach the lethal limit for an algal species to be replaced (out-competed) by a more tolerant form. The conditions need only be less favorable for that species and for more favorable another. Thus, in evaluating the effect of temperature on an algal community, the optimum temperature for the species is of prime concern. Differences in temperature optimum are among the major factors causing succession and dominance in algal communities. Whether or not increased water temperature would result in succession to more tolerant forms would also depend on other environmental conditions such as light and nutrient supply. Given sufficient light and nutrients, changes in water temperature can cause shifts in the species composition of an algal community.

In general the optimum temperature for growth of diatoms is from 15 to 25°C (59-77°F), that for green algae 25 to 35°C (77-95°F) and for blue-green algae 30 to 40°C (86-104°F) (Hawkes, 1969). According to Patrick (1969) the blue-green algae may assume dominance when temperatures are maintained above 35°C (95°F) for fairly long periods of time. If the temperature is held between about 32.2 and 35°C (90-95°F), an increase in green algae can be expected. Below these temperatures the native diatom population will be maintained unless the stream is polluted from other sources and the diatoms have already been replaced by green or blue-green algae. The effect of passage of algae through the condenser system of a power plant is uncertain. Temperatures above 34°C (93.2°F) will have a negative effect on algal survival and temperatures below this may decrease the photosynthetic activity of the algae. Since complex and dynamic algal communities are an integral part of any ecosystem, statements of consequences from altering the algal community structure by increased water temperature can only be speculative at best.

The selection preference towards blue-green algal forms is an advancement towards dominance by nuisance algae. The community increase in blue-green algal mass is characteristically greater than the concurrent decrease of other algal forms resulting in greater total biomass (Coutant, 1966). Further, the blue-green algae are not utilized in the food web to the extent that diatoms and green algae are. Thus, the increased production resulting from blue-green growth is lost to the higher trophic levels. The consequences of this are relatively unknown.

Marine Fish and Invertebrates - Data on thermal lethal limits for marine fish and invertebrates have been compiled by Bush *et al*. (1972). Because of the relatively small number of marine organisms for which there are available data, predictions of community response to elevated temperatures similar to those made for freshwater fish are not possible. Instead, general statements must suffice for guidelines and more emphasis must be placed on special site studies.

The thermal tolerances of the major groups of marine fish and invertebrates are summarized in Table 11 in order of increasing sensitivity or decreasing tolerance. As was the case in freshwater, the most sensitive groups of organisms are the fish with mean values for thermal tolerance (lethal) limits of 26.5°C (79.7°F) and 28.3°C (82.9°F) for Osteichthys and Chondrichthys, respectively. Data are also most prevalent for the bony fishes. Marine phytoplankton, macroalgae and rooted plants are not included in the table. However Marble and Mowell (1971) do indicate that thermal tolerance values are higher for these groups than for fish. Based on 22 values for marine phytoplankton, they gave a man tolerance value of 32.2°C (90°F) with a range of 16-41°C (60.8-105.8°F). The mean reported for red algae (Rhodophyceae) is 30.5°C (86.9°F) with a range of 27.0-35.0°C (80.6-95°F) (based on four species). The mean reported for brown algae (Phaeophyceae) is 37.0°C (98.6°F) with a range of 27.0-42.5°C (80.6-108.5°F). Three species of sea grasses were reported to have a mean thermal tolerance of 37.6°C (99.7°F) with a range of 33.0-45.0°C (91.4-113.0°F).

Although studies in the vicinity of power plants are scarce, several are significant. The flora of Morrow Bay, California, was found to be much more sensitive than the fauna to heated water discharge. Abundance and species diversity of both the aquatic plants and benthic organisms were reduced for about 500 feet away from the power plant; the flora however was affected much more severely. The fish population did not seem to be affected. The mean intake temperature of the water to the power station at Morrow Bay was 13.3°C (~56°F) with an annual range of 10-15.6°C (50-60°F). Temperature increments of 5.6°C (10°F) above normal were found within 500 feet of the discharge (Adams, 1969; Zeller and Rulifson, 1970). North and Adams (1969) suggested that if the water temperature increased 5.6°C (10°F) above summer ambient in areas on the Pacific coast all cold water biota would be eliminated and many of the species considered to be able to tolerate warm water would be adversely affected. An increase of 1.1°C (2°F) over normal summer temperatures was predicted to reduce or eliminate cold water biota during warm summers. They report that the Laminarian kelps of California will be severely affected by a 5.6°C (10°F) increase in water temperature in the summer months and that canopy deterioration of Macrocystis spp (kelp) frequently occurs when summer temperatures 1.1°C (2°F) greater than normal are maintained for several weeks. Such predictions are supported by the Morrow Bay experience.

Table 11. Thermal Tolerance of Various Groups of Marime Fish and Invertebrates

	Mean Temperature °C	°F	Range °C	Number of species
Order Thoracia (barnacles)	47.3	117.1	42.3 - 53.7	5
Class Xiphosura (horseshoe crabs)	42.7	108.9	42.7	1
Phylum Protozoa (unicellular animals)	38.5	101.3	34 - 43	2
Phylum Mollusca (molluscs)	37.2	99.0	29 - 45.5	44
Phylum Coelenterata (jellyfishes, hydroids, sea anemones, corals)	36.6	97.9	27.4 - 40.9	17
Phylum Annelida (segmented worms)	36.2	97.2	31.6 - 42.7	3
Phylum Echinodermata (sea urchins, starfishes)	35.9	96.6	29 - 40.7	13
Phylum Arthropoda* (arthropods)	34.5	94.1	17 - 53.7	52
Order Amphipoda (amphipods)	34.4	93.9	27.5 - 41	13
Order Decapoda (shrimps, lobsters, crabs)	32.9	91.2	17 - 43	26
Phylum Ctenophora (comb jellies)	32.1	89.8	26.5 - 38.2	4
Order Eucopepoda (copepods)	30.3	86.5	28 - 32.8	3
Order Anostraca (fairy shrimp)	30.0	86.0	28 - 42	2
Class Chondrichthys (fishes with cartilaginous skeletons)	28.3	82.9	26.7 - 29.8	4
Class Osteichthys (fishes with at least partly ossified skeletons)	26.5	79.7	10 - 38	58
Order Euphausiacea (euphasids)	25.1	77.2	23.2 - 27	2

**Includes several orders and a class listed separately

Fewer species and numbers of fish were reportedly found in the discharge area of the Turkey Point power station on Biscayne Bay, Florida. The effluent also altered the aquatic plant and benthic communities. Summer ambient temperatures were 30-31°C (86-87.8°F). Many plants and animals in the zone +4°C (7.2°F) above ambient were killed or greatly reduced. The turtle grass (Thalassia testudium) population was killed within the +4°C (7.2°F) isotherm. The turtle grass provided an important habitat and food source for many of the invertebrate species of the area. Within the +3°C (5.4°F) isotherm, species diversity and abundance of algae was reduced. The mollusks and crustaceans increased while the number of fish decreased in this area (Levin et al., 1972; Marble and Mowell, 1971).

Chemical Impact - The economic efficiency of thermal power cooling systems is heavily dependent upon chemical treatment in controlling corrosion, scaling, wood deterioration and biological growth. The chemical treatment used in cooling systems is discussed in detail by Saad (1971) and in section Task-3 Engineering Alternatives, of this report. A summary of chemical treatment employed in cooling systems is presented in Table 12. Because of the poor and scattered information available in the literature, the table is far from complete but offers a useful guideline and serves as a base for future study. Several of the chemicals used in water treatment are toxic to aquatic organisms. Of particular concern are the chromium and zinc compounds used in prevention of corrosion and the biocides used to control biological growth.

The scope of this section is to briefly discuss the impact of these chemicals if released to receiving waters. A discussion of the methods and cost of treatment of cooling water containing the chemicals used in control of corrosion, scaling, etc. is presented in section Task-3 Engineering Alternatives and by Saad (1971). The most widely used corrosion inhibitors in cooling systems are polyphosphates, silicates, the dianodic combination of phosphates and chromates and the zinc dianodic combination of zinc, phosphate and chromate.

Table 12. Summary of Chemicals Used in Cooling System Treatment

PROBLEM	CHEMICAL TREATMENT	CONTROL OF:
Scaling	Lime softening	Calcium carbonate
	Sulfuric acid addition	Calcium carbonate
	Chlorination	Organic slime control
	Orthophosphates (10-30ppm)	Calcium phosphate, iron
	pH control	Calcium sulfate
	Magnesium oxide	Silica
	Tannins, lignins, starches (30-100ppm)	Iron
	Polyacrylates, chelates	
Corrosion	Polyphosphates (2-10ppm) sodium tripolyphosphate sodium hexametaphosphate sodium decaphosphate	Calcium carbonate, CO_2 mineral acids
	pH adjustment	Reduce 50-100 times phosphate needed
	Dianodic	Pitting control
	phosphate (30-100ppm)	
	zinc (8-35ppm)	
	fluoride	Aluminum contamination
	chromium	Hydrogen sulfide, mercaptors
	Lignins	Corrosion cells
	Other inhibitors sodium nitrite silicates	
	Chromates (up to 10,000ppm)	Corrosion
	Nitrates	Control for high pH waters
	Soluble oils	Minimize couples
Micro-biological Fouling	Tannins, lignosulfanates (20-50ppm)	Anaerobic sulfur reducing forms
	Synthetic polyphosphates	Spore formers
	Stabilizing chelates	Aerobic sulfur bacteria
	Chlorine	Fungi
	Organic phosphates	
	Thiocyanates, Copper salts	Algae
Other Fouling	Polyelectrolytes	Muds, silt, etc.
	Polyacrolytes	Oils
	Lignosulfanates	
	Polyphosphates	
Wood Deterioration	Biocides (60-120ppm)	
	Chlorine, Bromines	
	Fungicides	

Examples of the polyphosphates are sodium tripolyphosphate, sodium hexametaphosphate and sodium decaphosphate. Although very little data are available, sodium phosphates do not seem to be strongly toxic to fish. Henderson et al. (1959) report the lethal level of sodium tripolyphosphate to the fathead minnow (Pimephales promelas) to be 140 mg/ℓ in soft water and from 1,300-1,350 mg/ℓ in hard water.

Phosphorus is one of the nutrients most often cited as the cuase of accelerated eutrophication resulting in nuisance concentrations of algae. Significantly increasing the phosphorus loading of a stream or lake may result in nuisance levels of algae. Surely algal growth can be limited by many nutrients such as nitrogen, carbon, iron and many trace elements. However phosphorus is most scarce naturally relative to algal needs. To limit nuisance growth of algae the National Technical Advisory Committee (1968) recommended as a guideline that the concentration of total phosphorus should not be increased to levels exceeding 100 μg/ℓ where streams enter lakes or reservoirs.

Sodium silicate used in corrosion prevention does not seem to be toxic to aquatic organisms in concentrations expected to be released from cooling systems. The toxicity threshold of sodium silicate to Daphnia magna, a zooplankton species, has been reported at 247 mg/ℓ. Sodium silicate was found not to be lethal to fingerling rainbow trout (Salmo gairdnerii) at a concentration of 256 mg/ℓ (McKee and Wolf, 1971). Some species are much more tolerant.

The use of the dianodic combination of phosphates and chromates and the zinc dianodic combination of zinc, phosphate and chromate to control corrosion can result in chromate concentrations as high as 500 mg/ℓ as CrO_4 (220 mg/ℓ as Cr) and zinc concentrations as high as 35 mg/ℓ in recirculating waters (Saad, 1971). Heavy metals such as zinc and trivalent chromium are considered highly toxic to fish (Doudoroff and Katz, 1953). Hexavalent chromium (in solutions of chromates or dichromates) was reported to be less toxic to fish than trivalent chromium and was classified as intermediate in toxicity to fish.

A wide range of chromium concentrations are reported as toxic to fish. For example, McKee and Wolf (1971) show a range in toxicity of hexavalent chromium to many species of fish from 5 to 520 mg/ℓ as Cr. In part the wide range reported in the literature is due to the widely varied experimental conditions and methods used in determining and reporting a toxic value. This makes it difficult to choose a limit that will prevent fish mortality from chromium salts. Moreover, the concentration that can be tolerated indefinitely is more important and also elusive. The National Technical Advisory Committee (NTAC) (1968) has recommended a fraction of the TLm (an application factor) that would provide protection indefinitely (1/20 of the 96 hour TLm value in freshwater at any given time or place). Further, the 24 hour average of the toxic substance should not exceed 1/100 of the TLm. They also recommend an application factor for metals in marine and estuarine environments of 1/100 of the 96 hour TLm. Where application factors have been determined for a specific toxicant NTAC recommends the use of that factor.

The range in 96 hour TLm values for hexavalent chromium are from 17.6 to 177 with a mean of about 104 mg/ℓ as Cr for six species of fish (Cairns, 1957; Kemp _et al._, 1971; McKee and Wolf, 1971; Patrick _et al._, 1968; Trama and Benoit, 1960; Wallen _et al._, 1957). Using an application factor of 1/100 of the 96 hour TLm, the concentration of hexavalent chromium assumed to be safe for fish would be 1.0 or 0.176 mg/ℓ Cr for the mean or lowest 96 hour TLm value, respectively.

Species in the aquatic community besides fish, such as zooplankton and algae, seem to be more sensitive to chromium (Dowden and Bennet, 1965; Patrick _et al._, 1968; McCann, 1972; and the National Technical Advisory Committee, 1968). Data are inadequate to permit a well defined guideline, but the value of 0.05 mg/ℓ of chromium recommended by McKee and Wolf (1971) to protect all aquatic life seems to be the best estimate available.

Zinc is extremely toxic to fish. The range of 96 hour TLm to eight species of fish is from 0.88 to 35.5 with a mean of 10.14 mg/ℓ Zn (Ball, 1967; Brungs, 1969; Cairns, 1957; Kemp et al., 1971; McKee and Wolf, 1971; Mount, 1966; Patrick et al., 1968). Using the recommended National Technical Advisory Committee application factor of 1/100 of the 96 hour TLm for the mean and lowest TLm value gives an assumed safe concentration of about 0.1 and 0.01, respectively. Since concentrations as low as 0.01 mg/ℓ of zinc have been reported to be toxic to fish (McKee and Wolf, 1971), 0.01 mg/ℓ seems more desirable as a limit. When exposure to the toxicant is for short periods, 0.1 mg/ℓ may provide adequate protection. Other forms of aquatic life do not seem to be more sensitive to zinc than are the fishes.

The chemicals used to control biological fouling and wood deterioration are presented in section Task-3 Engineering Alternatives and by Saad (1971). Those chemicals for which toxicity results are available are chlorine, acrolein and copper salts used in prevention of biological fouling and chlorophenol used for control of wood deterioration. Chlorine is the most widely used agent in controlling biological fouling and wood deterioration.

Hydrolysis and ionization of Cl_2 gas occur when added to water resulting in HOCl and OCl^-. The toxicity of HOCl to microorganisms is from 40 to 80 times that of OCl^-. There exists a wide discrepancy in the concentrations of free chlorine (HOCl and OCl^-) found toxic to fish (0.03 to 3.0 mg/ℓ) and the concentrations in which fish have been reported to survive (0.1 to 5.0 mg/ℓ) (McKee and Wolf, 1971). The discrepancy results from differences in the toxicity of total chlorine due to variations in water quality and make it impossible to estimate a toxic limit for free chlorine.

Free chlorine will combine with reducing agents such as NO_2^-, H_2S, Fe^{++},

Mn^{++} and organic matter. Of importance in fish toxicity are the chloramines. Data cited by McKee and Wolf (1971) give conflicting evidence as to whether chloramines or free chlorine are more toxic to fish. The dosage range of chlorine to control slime growth ranges from 1 to 10 mg/ℓ which is similar to that used in an activated sludge treatment plant for disinfection (Metcalf and Eddy, Inc., 1972). Since chlorination procedures used in activated sludge treatment plants have resulted in fish mortality in receiving waters, it is strongly recommended that the chlorine residual in the effluent be kept below 0.05 mg/ℓ unless contact time is less than one hour.

Few data exist on the toxicity of acrolein to aquatic organisms. Concentrations recorded toxic to salmon, killifish and shrimp were 0.08, 0.24 and 0.1 mg/ℓ respectively (Kemp *et al*., 1971). Data are too incomplete to set a guideline; caution is urged in the discharge of acrolein.

The copper salt most utilized in the control of biological growth is copper sulfate. Concentrations of copper sulfate from 0.002 to 200 mg/ℓ have been reported lethal to many kinds of fish in a variety of water conditions. Also concentrations from 0.14 to 900 mg/ℓ have been reported as non-toxic to a variety of fish. Copper sulfate requirements to control plankton range from 0.05 to 12 mg/ℓ. For control of other types of aquatic forms concentrations of 0.1 to 20 mg/ℓ have been used (McKee and Wolf, 1971). Because of its high toxicity to aquatic life McKee and Wolf (1971) recommended a threshold concentration of 0.02 mg/ℓ Cu to protect aquatic organisms in fresh water and 0.05 mg/ℓ Cu in sea water. The freshwater limit is very close to that Mount (1968) found as the maximum acceptable concentration for indefinite exposure (threshold concentration) of copper sulfate - Cu for the fathead minnow, *Pimephales promelas*. He reported the threshold concentration to be between 0.015 and 0.033 mg/ℓ Cu.

Chlorophenol has been reported to be toxic to fish in concentrations from 8.1 - 58 mg/ℓ. 96 hour TLm values for the fathead minnow (*Pimephales* promelas), bluegill (Lepomis macrochirus), goldfish (Carassius auratus) and the guppy (Lebistes reticulatus) have been reported at 12, 10, 14 and 23 mg/ℓ respectively (Kemp et al., 1971). Using an application factor of 1/100 of the mean 96 hour TLm would give a value of about 0.15 mg/ℓ as the maximum concentration assumed to be safe for fish.

The National Technical Advisory Committee (1968) has recommended the following formula to estimate the permissible concentration of mixtures of toxic substances:

$$\frac{Ca}{La} + \frac{Cb}{Lb} \dots + \frac{Cn}{Ln} \leq 1$$

where Ca, Cb and Cn are the measured concentrations of toxic substances in the water and La, Lb and Ln are the concentrations permissible for each toxic substance. If the sum of the fractions exceed 1, then restriction of one or more of the toxic substances is necessary. This method of summing the effects of toxic materials was also reported by Brown (1968). The method assumes that all toxic materials can contribute in a similar manner to the total toxicity of a mixture. Brown (1968) cites several examples where this condition was satisfied often enough to make such a method a reasonable estimation of the toxicity of a mixture of toxicants in the environment.

TASK 3 - ENGINEERING ALTERNATIVES

Evaluation of engineering alternatives that can reduce the environmental impact of thermal power plants is the major goal of this research. Research emphasis has been placed on developing an analytical framework that will specify the type and resolution of data to be used in such evaluations. Previously, the evaluation of engineering alternatives has been accomplished in a fragmented manner. It was necessary in this study to equalize data; data on heat sources and cooling systems were aggregated and abstracted to simplify the evaluation, while data on chemicals, intakes and non-water environmental impacts were generated in this study. The project officer directed that nuclear radiation impacts be excluded from this study.

The following sections describe the specific models developed for the decision tree analysis. The first two sections discuss the results of major research efforts in this study to (1) define and evaluate engineering alternatives for screening intakes to prevent damage to the physical plant and protect fishes and (2) to identify chemicals used in the control of corrosion, scaling, and fouling of process and cooling waters. The chemical study also produced a model to evaluate the impact of windage losses and blowdown chemical concentrations on plant cost and ecological response. The final parts of this section describe the models that were modified rather than developed by this study. The engineering alternatives for cooling were modified from Dynatech (1971), and the engineering alternatives for transmission of power were abstracted from BPA data reported by Meyer (1972). The air pollution, solid waste, and land management impacts were defined by previous decisions in the tree and are modeled as dependent variables.

Task 3: Engineering Alternatives, Screening of Intakes

The impact of screening on the environment and the cost of power generation is directly related to the amount as well as the fraction of available water diverted by the system. For a 1,000 MWe plant a once-through cooling system will require on the order of one to two thousand cubic feet per second (cfs) of cooling water, while a recirculating evaporative cooling system will require less than 100 cfs. Screening is required to protect the plant from debris in the intake water as well as to prevent aquatic life from entering the plant. Obviously, screens and trash racks will prevent debris from entering the system and damaging or plugging the cooling system. Screens are also the most effective device to prevent fish from entering the cooling system. An alternative to screening are the use of artificial guidance devices to direct fish away from intakes. An extensive literature review conducted as part of this research revealed that little success has been achieved with any form of artificial guidance including light, velocity, channel configuration, temperature, electrical shock, bubble curtains or chemicals. These methods can be used to complement mechanical screens; proper design will utilize these factors of fish guidance. Electric screens have proven successful as barriers but not as guidance mechanisms.

The engineering alternatives for intakes are basically screens or no screens. Once an engineering decision has been made, the effectiveness of a screen is not so much a function of cost, but of design. The design for minimum fish mortality is almost independent of screen cost. Fish mortality in screens can be as high as 50 percent when they are trapped on the screens (either fixed or rotary). Once trapped the fish usually suffocate unless by-pass configurations are properly designed. Head losses across the screens should not exceed 0.02 feet of water. The screen and by-pass configuration must provide a smooth path along the screens to permit lateral movement of the trapped fishes. Improper screen designs have corners that trap fish as they move laterally across the screen or force fish to swim upstream to escape. A comparison of proper and improper screen configurations is shown in Appendix A.

The cost differences between configurations are minimal and costs for mechanically operated screens are estimated as $240 per square foot of contact surface ($100 for screen face and $140 for support structure). Intake structures and pumps are not included in these costs. The annual operation and maintenance costs were found to be approximately 10 percent of the capital investment. If a design approach velocity of 0.5 fps is used, the screening costs would be $480 per cfs.

The purpose of a screen will vary with the type of cooling water source. Screens for river intakes are usually be designed to prevent the intake of young anadromous species and they must accommodate the debris, sand and silts, that can clog the screen and abrade the cleaning mechanism.

Screening design for lake intakes is simplified because of the lack of currents and the smaller level fluctuations that are encountered in rivers. In lakes, the location of the intake sometimes can be selected to avoid areas where fishes are present, while a river intake will usually encounter all the fishes. In both lakes and rivers the exit from the screen by-passes must be designed so the fishes are not guided to areas where predators can concentrate.

The design of screens for salt water cooling systems is complicated by (1) the tidal fluctuations that create positive, negative, and slack flow conditions, (2) the presence of active fouling organisms present in the water, (3) the presence of organisms and larvae of most important local food fishes, and (4) the corrosive nature of sea water. A pump is required to provide flow for proper operation of a screen by-pass. Pumps are available that can pump fish without major mortalities. Unlike freshwater fouling organisms, those in salt water can freeze guides and bearings. Barnacles are attracted to intake, screen, and outfalls and can plug these systems. These can be controlled by chemicals (see chemical treatment section) or freshwater backwashes. The most significant difference between screens in fresh and salt water is the presence of eggs and larvae of demersal or pelagic fishes and bivalves (clams, scallops, and oysters), crustaceans (crabs and shrimp), and gastropods (abalones) in salt water. The screening decision must be based on the size of organism to be screened. In the case of river screens only the migrants and adults are of prime concern. In the case of salt water screens, the abundant eggs and larvae of high valued food fish present a serious problem. The alternatives may be to select locations in non-nursery areas or employ infiltration beds. Screens are not effective against organisms such as larvae and eggs.

Very little cost or performance data are available for infiltration beds but rough cost estimates suggests $1,000 per cfs. Major cleaning or back-washing problems will be encountered with infiltration beds. When screens are used in salt water, they must be constructed of stainless steel in order to avoid corrosion. While impeding corrosion, the use of stainless steel increases screening costs. The problem of fouling remains despite the change in screening material.

The engineering alternatives to minimize fish damage at intakes are a zero/one decision. Once the type of protection is selected, the design of the system must consider the behavior of the fishes. Increasing the cost of screen systems will not always increase the protection. The proper design appears to be an ill-defined "art" rather than a science. The research effort of this study was directed toward documenting this art so that it may be approached as a science.

The screening and intake alternatives modeled in the decision tree are of the zero/one form. The performance, cost and impact of the intake system are functions of the intake water flow and the fraction of the receiving water removed by the intake.

Task 3: Engineering Alternatives, Chemical Discharges from Thermal Power Plants

Treatment of cooling waters used in thermal power plants to reduce corrosion or fouling is a common practice. Chemicals can be removed by pretreatment of waters supplied to the cooling system or chemicals may be added directly to the water in the cooling system (Table 12). In either event, such treatment will create wastewater streams that contain significant levels of chemicals that may damage the environment. The environmental impact of chemicals released by thermal power plants has not been well documented in the literature, and definition of the problem is difficult. To provide sufficient data to construct a model of chemical discharges from thermal power plants, Saad (1971) conducted a literature review and assessment. No information was uncovered that would permit the estimation of chemical concentrations in water from air cleaning devices and only chemical discharges from the cooling system could be modeled. Over 70 journal articles and documents were analyzed as a basis for this model. Based on these data, a simple model is developed for the estimation of chemical discharges from thermal power plants.

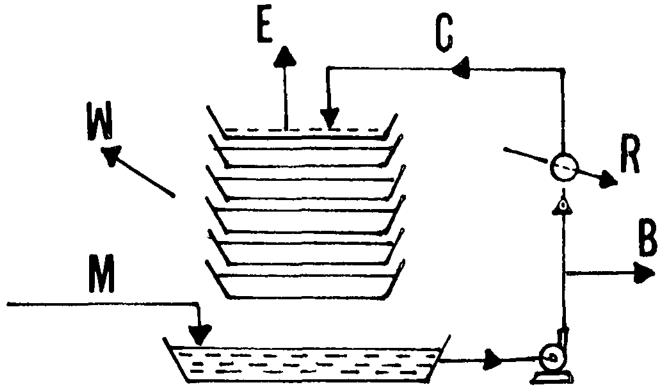
The model is formulated to estimate the chemical discharges from (1) once-through cooling systems, (2) cooling ponds, (3) evaporative cooling towers, (4) dry cooling towers, and (5) any combination of these basic systems such as tapping or variable cooling systems cycles. These cooling systems are widely discussed in the literature (FWPCA, 1968) and their characteristics are not repeated in this report.

The general water balance for thermal power plant cooling system is shown in Figure 7 and is expressed as

$$M = E + B + W \tag{1}$$

where M = make-up water flow rate

B = blow down flow rate



Definitions:

M = Make-up Water (gpm)

B = Blow-down (gpm)

C = Circulation (gpm)

E = Evaporation (gpm)

R = Condenser

W = Windage or drift (gpm)

X = Salt Concentration (ppm)

$X_{m,c}$ = Concentrations (ppm) of the make-up and circulating waters respectively

Figure 7. Water and Chemical Balances for Thermal Power Plants

E = evaporation rate

W = windage or drift loss rate

C = circulation flow rate in system

Water is discharged from ponds and wet cooling systems by two basic means besides evaporation. Blowdown is term used to described water withdrawn from the cooling system to maintain a desired concentration of chemicals in the recirculating system. Windage and drift are losses due to natural processes such as ambient wind or tower draft carrying away, but not evaporating, water droplets. Both methods achieve the same effect in terms of system water loss. If the drift and windage losses were of the magnitude necessary to maintain the desired chemical concentration in the circulating water, no blowdown would be necessary. Dry cooling towers utilize on only blowdown to maintain chemical concentrations in the recirculating system.

For the various cooling system alternatives, this equation will have the following specific forms;

1. Once-through system

   $M \sim C = B; \quad W = 0; \quad E \sim 0$

   since the water is not recirculated and evaporation occurs after discharge
2. Wet cooling towers and ponds

   $M = E + B + W$
3. Dry cooling towers

   $M = B \neq C; \quad E \neq W = 0$

   since the recirculating cooling water is not exposed to the atmosphere

A total solids material balance can be defined for these cooling systems with the following general expression;

$$A + MX_m = (B + W)X_c \qquad (2)$$

where X_m = concentration of material in make-up water

X_c = concentration of material in circulating water

A = mass of material added/unit time

Equation 2 can also be used to describe the material balance for specific chemicals that are added to the cooling system, but do not react chemically or biologically. In this case X_m, X_c and A refer to a specific chemical. When the chemicals added to the cooling system react, two situations are of great interest. The first is when the chemical added is toxic or has significant environmental impact and is consumed or reacts in the system.

In this case can be expressed by modifying equation 2;

$$\gamma A + MX_m = (B + W)X_c$$

where γ is the fraction of A that is in stoichiometric excess at the amount of A required for chemical reaction. The second case would be when the addition of a chemical would cause a reaction with other chemicals in the cooling system to form a product that is undesirable. The production of chloro-phenals is an example. The mass balance in these cases must be based on stoichiometric balances for the specific reactants.

The other major source of chemical discharge from cooling systems is the chemicals removed by pretreatment of make-up water. The expression for these wastes is given as;

$$M(X_{in} - X_m) + P \tag{3}$$

where X_{in} = concentration of material in make-up water prior to treatment

P = mass of chemicals added in treatment

The expression can be written on a total solids basis or for specific conservative chemicals. Figure 8 summarizes the alternative chemical adding processes that can be introduced into the cooling water system.

The volume flow rates for the chemical discharge model are defined by

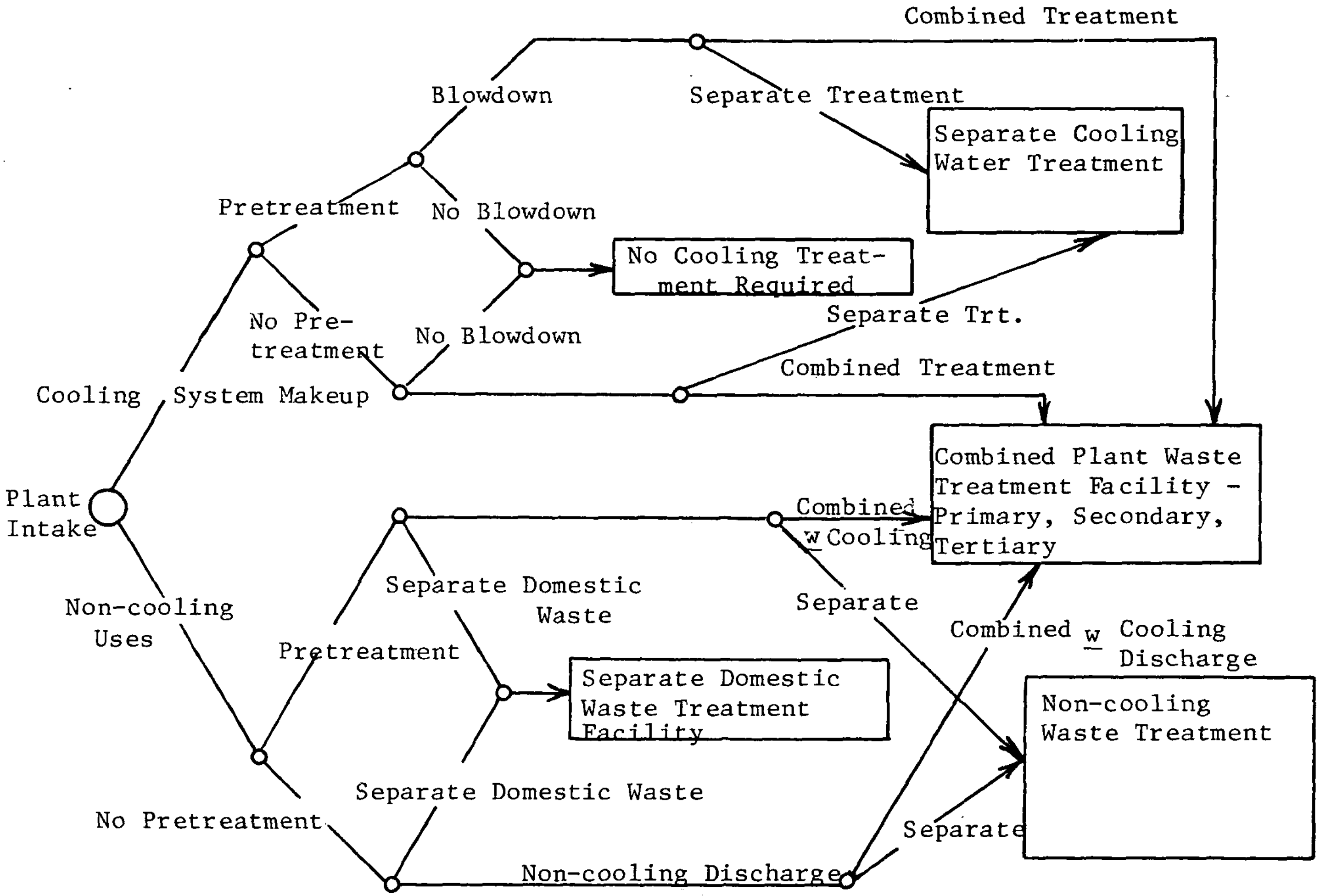


Figure 8. Power Plant Water System

the turbine heat rate, the type of cooling system, the type of cooling water, environmental conditions, and the water quality standards for the effluent or receiving waters. The amount of water passing through the condensers C, is determined by the amount of heat to be transferred and the allowable increase in cooling water temperature:

$$C = \frac{H}{C_p \Delta T} \quad \text{(lb/sec)} \tag{4}$$

where H = heat removed per unit time, Btu/sec

ΔT = allowable temperature increase of coolant, °F

C_p = heat capacity of coolant, Btu/lb F°

When the heat from the coolant is dissipated by evaporation, the water lost in evaporation is given by:

$$E = \frac{H}{L} \alpha \text{ (lb/sec)} \tag{5}$$

where L is the latent heat of evaporation of the coolant water in Btu/lb. For water L is approximately 970 Btu/lb and C_p is approximately 1 Btu/lb/°F. °F

The parameter α is the fraction of the heat rejected from the system via the evaporative cooling process. Some heat is rejected by advection or in the form of temperature increase in the blowdown. The fraction of the circulating water evaporated can be determined by dividing equation (6) by equation (5). The resulting equation gives the ratio of E to C as a function of α and ΔT.

The percent of cooling water evaporated can be expressed as:

$$\frac{E}{C} \times 100 = \frac{\alpha H/L\ 100}{H/C_p\ \Delta T} = \frac{\alpha 100\ C_p \Delta T}{L} = \frac{100\ \Delta T \alpha}{1000}$$

$$\frac{E}{C} = \frac{\alpha \Delta T}{10} \ (\%) \tag{6}$$

However, as water is lost, the chemical concentration of the remaining cooling water increases. In order to maintain the concentration at a desired level, some of the coolant can be withdrawn from the system as the "blow-down", B.

For freshwater coolant, no blow-down may be required in an open recycle system if windage losses remove a significant fraction of the coolant stream and maintain the desired chemical concentration.

Using the mass balance of Equation (2) and neglecting the addition of make-up chemicals and treatment, the ratio of chemicals in the coolant to that in the make up is:

$$\frac{X_c}{X_m} = \frac{M}{B + W} \tag{7}$$

The sum B + W can be denoted as D, the water discharged from the system. D can be expressed in terms of the flow rate of circulation water and allowable temperature use of this water:

$$\frac{X_c}{X_m} = \frac{D + \frac{\Delta T \cdot \alpha}{970} C}{D}$$

$$D = \frac{\alpha \Delta T C}{970(\frac{X_c}{X_m} - 1)} = \frac{\alpha H}{C_p(970)\ (\frac{X_c}{X_m} - 1)} \tag{8}$$

This expression can be used to define the water discharge required to maintain any given level of chemical in the cooling water stream.

The parameter α is equal to 1.0 for the case of pure evaporative heat transfer. For mechanical and natural draft evaporative cooling tower recirculating system α is usually less than 1.0 but greater than 0.8. Cooling ponds have natural evaporation in addition to the evaporative load imposed by the steam plant and thus have α values greater than 1.0.

Figure 9 shows that a small fraction of the circulating water need be discharged to maintain stable chemical concentrations for cycles of

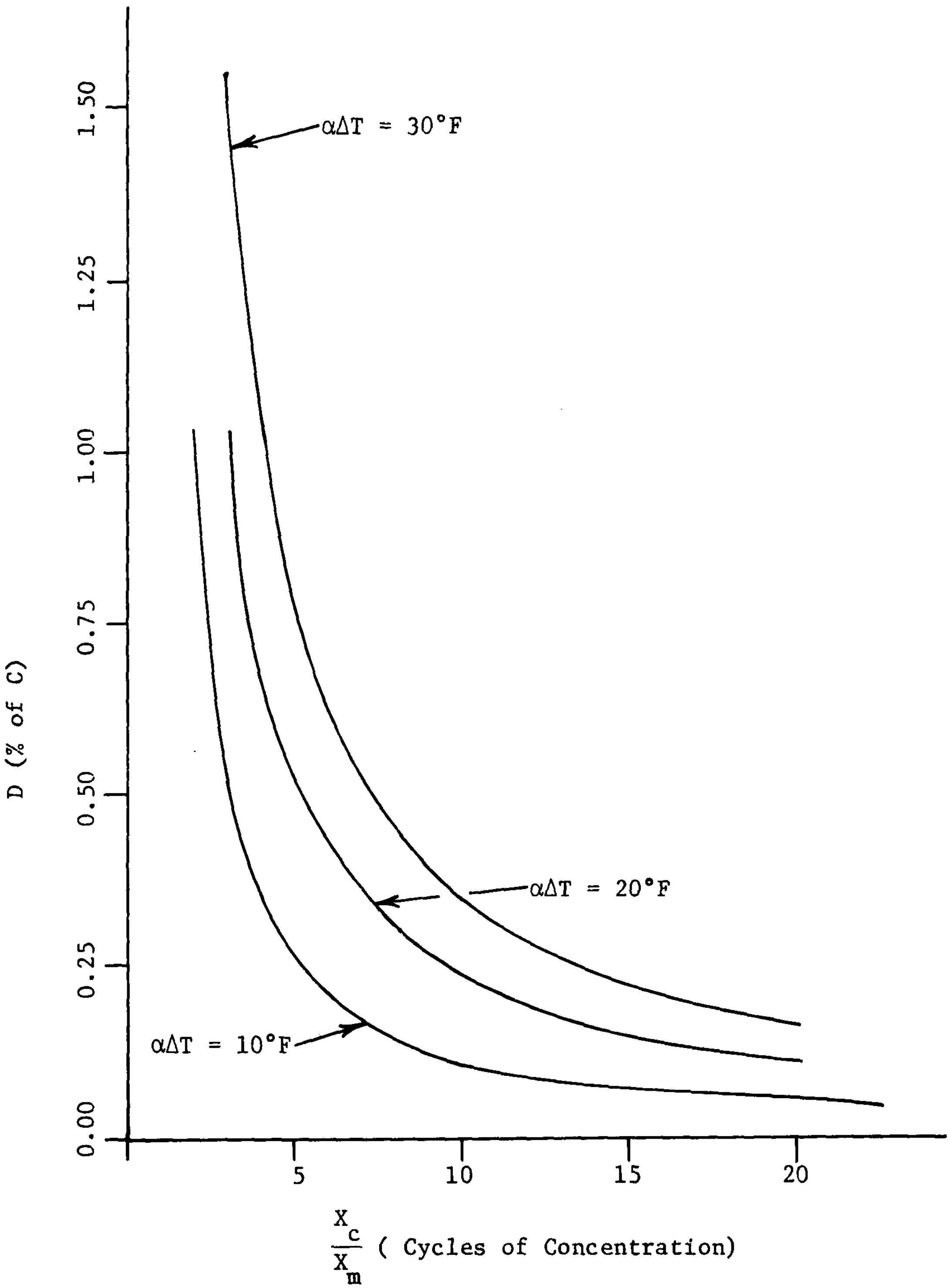


Figure 9. Water Discharge as a Function of Cooling Water Chemical Concentration

concentration in excess of 5. Blowdown is necessary for all systems as current generation evaporative cooling towers are designed for drift losses of 0.01% or less. Salt water natural draft towers are designed for 0.002% (circulation) drift in order to minimize detrimental effects of salt spray. Drift losses can be seen to only be significant in discharge calculations for very high cycles of concentration (greater than 20). The maximum value of cycles of concentration is not limited by drift in modern towers but by inlet water quality. Both blowdown and drift remove chemicals from the recirculating system. One discharges to the air. The other to the water environment. It is essentially impossible to treat drift as a source. Drift can only be minimized by design.

For sea water systems the cycles of concentration is usually kept lower than in fresh water systems. The cycles of concentration are kept low to prevent possible problems with salt precipitation and corrosion. Sea water systems have correspondingly higher blowdown rates. Drift, as mentioned early, is designed to be minimal due to possible damaging effects. Some salt systems with cycles of concentration less than 2 are essentially flow through devices used to lower discharge temperatures.

It should be restated that all of the above work is concerned with conservative materials in open recirculating systems. For example the above work is not applicable to chlorine which is removed from the system by the scrubbing action of evaporative towers. The above equations are good for other chemicals used in the cooling systems for which reaction rate constants are very slow or which are added in excess concentrations. For a particular system it will be necessary to determine which water quality parameter is limiting and set the cycles of concentration by that parameters. Chemical additions may be necessary to adjust other water quality parameters to values desired. Determination of an optimal chemical system is a matter for detailed plant design.

Calculation of Treatment Costs - The water streams in a power plant that may require treatment are the make-up water M, the blow-down B, and the noncooling water stream. The use of water recirculation significantly reduces the volume of water to be treated to a few percent of that required for once through cooling. The previous discussion develops the models to predict the volume of water to be treated. This section describes the procedure to estimate the degree and cost of treatment. An alternative to chemical control is mechanical cleaning of the system. This process was not modelled.

Assuming that water quality standards are established for each type of pollutant in the wastewater from a power plant, the degree of treatment can be defined as the difference between the blow-down or wastewater concentration and the allowable effluent concentration defined by these standards. Similarly, given the quality of intake water and the quality criteria for make-up water the treatment requirements for intake water can be established. Table 13 summarizes the treatment requirement for removal of anti-corrosion or fouling agents added to cooling water. Since most of these agents are dissolved and cannot be effectively removed by biological treatment, chemical or physical treatment is required. Processes such as ion exhange, electrodylasis, or other forms of desalination, chemical precipitation, or carbon absorption are required. The cost of these types of treatment reported for waste waters can be expressed as:

$T.C. = AF^b$ ¢/1000 gallons

b, A = empirical constants

F = water volume/day to be treated, mgd

Typical values for the constants are:

	A	b
microstraining	1.7	-.051
coagulation and sedimentation	4	-.02
sand filtration	8	-.4

Table 13. Disposal Characteristics and Treatment Requirements of Cooling Tower Chemicals (after Saad, 1971)

Inhibitor System	Concentration in Recirculating Water	Stream Standards	Ratio Blow-down Conc. Stream Std.	Disposal Cost $/ 1000 gal Blow-down
Chromate only	200-500 as in CrO_4	0.05 as CrO_4 3.0 as Cr	10,000 80	0.70
Zinc Chromate	8-35 as Zn 17-65 as CrO_4	5 as Zn 0.05 as CrO_4	7 1,300	0.16
Chromate Phosphate Zinc	10-15 as CrO_4 30-45 as PO_4 8-35 as Zn	0.05 as CrO_4 3.0 as Cr 0.3 as PO_4 5 as Zn 0.05 as Zn	300 2 150 7 35	0.13
Phosphate	15-60 as PO_4	0.3 as PO_4	200	0.12
Zinc Phosphate	8-35 as Zn 15-60 as PO_4	5 as Zn 0.3 as PO_4	7 200	0.14
Phosphate Organic	15-60 as PO_4 3-10 as organic	0.3 as PO_4	200	0.13
Organic only	100-200 as organic 10 est. as BOD 100 est. as COD 50 est. as CCl_4 extract 5 est. as MBAS	20 as BOD 40 as COD 0.2 as exotic organic	2.5 250	1.25
Organic Biocide	30 as Chlorophenol 5 as sulfone 1 as thiocynate	0.2 as phenol 0.1 as is (est.) 5.0 as SCN (est.)	100 50	

carbon adsorption	16	-.3
electrodialysis	21	-.18

These are based on the values of Smith (1967) and can be adjusted for inflation, cost increases, and amortization schedule. There are no data for cooling water treatment specifically and these data of Smith are reported for an estimate. The coagulation and sedimentation, and sand filtration are primarily pretreatment processes, while all can be used for post treatment.

These costs do not include costs of ultimate disposal of brines or sludges produced by water treatment. Many water treatment systems discharge these wastes to the receiving waters or employ land disposal. Cost data for such systems are inadequate to formulate cost equations. The model will account for these ultimate disposal costs by a constant, α, to reflect these added costs. The treatment cost will be represented by the expression

$$T.C. = \alpha AF^{b}$$

The levels of treatment have been classified into three major types: physical-chemical for removal of solids, hardness, and microorganisms; biological, to remove oxygen demanding waste; and advanced, to remove toxic chemicals, biocides, fungicides, salts, and corrosion and scaling inhibitors. Make-up water treatment is limited to only physical-chemical, while discharges can provide any or all types of treatment depending on the flow separation designed for the discharge streams. With the exception of once-through cooling, the cost of treatment should not be large even for complete purification of the water since the volumes are small (a few percent of once-through cooling volumes). All costs for treatment include ultimate disposal of sludges and brines produced in the treatment process. Treatment is assumed to be sufficient to avoid environmental impact from the chemicals since total rather than partial treatment is proposed. Cost data are insufficient to permit the estimation of partial treatment costs.

Task 3: Engineering Alternatives, Cooling Systems

All thermal power systems require an engineered system to dissipate heat in a manner not damaging to the surrounding environment. There are six major methods commonly considered for heat rejection. These systems are shown in Table 14 together with relevant design parameters as summarized by Hauser, *et al*. (1971). Several comprehensive discussions (Edinger and Geyer, 1965, Parker and Krenkel, 1969a and 1969, NAE, 1972, FWPCA, 1970) have been published giving extensive reviews of alternative cooling systems. More recent publications (e.g. Thackston and Parker, 1971, Brady, 1970 and Kadel, 1970) have tended to deal with the performance of individual components or to elucidate solutions and refinements of cooling tower performance and designs previously set forth by McKelvey and Brooke (1959).

Matching of all the components in a large steam-electric power plant is a complicated, multiparametric process. Steam plant operating characteristics, environmental conditions (air and water data) and economic factos must be combined in a calculational package to yield an optimal configuration. Two methods of cooling system calculation appear in the recent literature (Hauser *et al*., 1971 and Dynatech, 1971).

Hauser *et al*. (1971) discuss the multiplicity of problems inherent in cooling system optimization studies. They point out that the system under consideration extends from the last stage design of the steam turbine through physical system components of condensers, pumps, pipes and heat dissipation devices. Hauser *et al*. conclude that final detailed design methods are necessary to predict system performance with enough accuracy to discern savings and cost potentials of alternative systems.

The Dynatech (1971) sutdy does not contain all parameters specified in the work of Hauser *et al*. (1971). It was available in a computerized package and did contain many of the major design parameters of the Hauser *et al*. model. The Dynatech package was evaluated and found to give

COOLING SYSTEM	Wet Bulb Temperature	Dry Bulb Temperature	Barometric Press	Wind Speed and Direction	Cloud Cover	Latitude	Solar Radiation	Stream-Flow (Make-up - H_2O)
	DESIGN PARAMETERS							
Once-Through	1	1	2	1	1	2	1	1
Cooling Pond	1	1	2	1	1	2	1	2
Spray Pond	1	1	2	1	2	2	2	2
Natural Draft Wet Tower	1	1	2	0	0	0	0	2
Mechanical Draft Wet Tower	1	2	2	0	0	0	0	2
Dry Cooling Tower	2	1	2	0	0	0	0	0

Key:

0 = Parameter is of minor importance in determining system performance

1 = Parameter is of prime importance in determining system performance

2 = Parameter is of secondary importance in determining system performance

Table 14. Major Cooling System Types and Relevant Environmental Design Parameters (after Hauser et al., 1971)

adequate results of necessary accuracy for use in a preliminary site planning and evaluation model. This package contained routines for calculating the performance of a given steam turbine system with alternative cooling devices (once-through river, cooling pond, mechanical-draft evaporative tower and natural-draft evaporative tower). This package of cooling routines slightly modified, formed the cooling calculational level in the thermal siting analysis decision tree.

Traditional analysis of engineering cooling alternatives ends with the determination of the economic parameters for a given system and possibly a determination of the resulting river temperature from a thermal discharge. All cooling analyses are extended in this study to include prediction of biological impact based on the mixed river temperature at the point of thermal discharge. This provides an additional measure of the impact of thermal power plants. Table 5 through 10 presented in Task 2 are used as the basis of this analysis to predict the response of fishes to the river in question with and without the thermal plant in operation. Similarly, the chemicals used in cooling systems are defined and their impact estimated.

Once-through, pond, mechanical draft wet tower and natural draft wet tower performances are calculated using the basic Dynatech (1971) cooling package. Hauser and Oleson (1970) summarize the effects of alternative cooling devices on water consumption as functions of several parameters. For most closed cycle evaporative devices, the water consumption is roughly twice that of a once-through cooled system ($\simeq$ 1 gal/net kWh v. $\simeq$ 0.5 gal/net kWh).

Use of an evaporative cooling system does not necessarily eliminate discharges to the natural waters. These discharges to the atmosphere and receiving waters are summarized for the various cooling systems in Table 15.

COOLING DEVICE	WATER DISCHARGES		AIR DISCHARGES	
	WATER QUANTITY	QUALITY[2]	QUANTITY	QUALITY
Cooling Pond	Variable[1]	System	Evaporation	Pure
Spray Pond	Variable[1]	System	Evap. + Windage	System[3]
Mechanical Draft Evaporative Tower	Blowdown[1]	System	Drift + Windage + Evaporation	System[3]
Natural Draft Evaporative Tower	Blowdown[1]	System	Drift + Windage + Evaporation	System[3]

Notes:

1. Blowdown quantity applies to recirculating systems only. Some ponds may have no discharge. Topping(flow-through) devices will have large discharges of essentially the same magnitude as the condenser flow.
2. Assumes no treatment. Quality of effluent is the same as is found in the operating system.
3. Quality factor applies to windage and drift losses only. The evaporite is assumed pure.

Table 15. Evaporative Cooling System Discharges to Air and Water

Task 3: Engineering Alternatives, Control of Non-Water Impacts

The decision tree has been constructed to compute land requirements and non-water waste loads that can be used in evaluating the impact of power plant siting. The land requirements for any given path of the decision tree are the sum of the power plant, cooling and transmission requirements. The power plant land requirements are 500 acres for the baseline plant, unless modified by input. The cooling system land requirements are computed from the Dynatech (1971) model for cooling ponds, or .0046 acres/MW for mechanical draft system and .0007 acres/MW for natural draft systems (Kolflat, 1971). The transmission land requirements are correlated with transmission voltage and distance. Table 16 summarizes the values used for this study. The total land requirements can be used to estimate land cost as well as the increasing demand for land as power demands increase in a region.

When fossil fuels are used to generate power, the air emissions are estimated by the model. The pollutant emission factors of Duprey (1968) and Marks (1958) have been incorporated in this model. The emission factors are:

	pounds/ton of coal
Aldehydes	0.0005
Carbon Monoxides	0.5
Hydrocarbons	0.2
Oxides of Nitrogen	20
Oxides of Sulfur	38

The ash is estimated as 0.24 pounds per kWh and is either a solid waste or emission problem. The water emissions are computed as the sum of vapor and droplets. Vapor is equated to evaporation loss and droplets are equated to windage losses. The amount of chemicals released in the windage is based on the system concentration.

Transmission Voltage (KV)	Double Circuit Capacity (MWe)	Required Right-of-Way (Ft.)	Area per Mile (Acres)	Area per MWe-mile	Minimum Loss/Distance (%) (mi.)	Loss Functions %/100 mi. transmitted
345	500	125	15	0.03	2.2/200	$2.2 + .05(x-2)^2$
500	1,500	150	18	0.012	1.2/300	$1.2 + .04x$
700	3,000	175	21	0.007	1.0/300	$1.0 + .03x$

x = transmission distance in 100's of miles

Table 16. Transmission Line Parameters (McIntyre, 1970)

The computations of these emissions provide bases for treatment decisions to reduce emission levels. The introduction of additional nodes for these decisions is simple in the proposed analytical framework.

COMPUTER MODEL - Calculational Routines

The following sections discuss the elements of the program. The discussion begins with the main call sequence and proceeds through the subroutines used at each tree level.

The thermal analysis tree structure was conceived to contain six decision levels. The levels are:
1. site - transmission path
2. plant type
3. condenser cooling means
4. water intake screening alternatives
5. water chemical treatment alternatives

The tree diagram was selected as the method for portraying the range of alternatives for a given site. Evaluation of the tree proceeds from left to right with the information from the previous level(s) providing input to the calculational routines in the subsequent levels. For each identified set of alternatives the payoff routine outputs:
1. water use information
2. air and water discharge information
3. thermal status of representative water body
4. land use information
5. power cost information

A complete program listing and list of variables are provided in the Appendix B.

The main program (BUILD) part of this work is composed of two sets of call sequences. The main routine is an executive routine only. All system calculations are performed in the subroutines for each level of the tree diagram. The first action of the main program is to list or not list the thermal plant tree diagram depending upon the value of tree print flag (ITO). The tree is printed by calling the subprogram TREE.

The program call sequence can operate in either of two modes depending upon the call sequence control flag (CF). For ICF = 1 the program is placed in the single payoff mode. For ICF = 0 the program will evaluate the payoffs for all options subject to the values of the other control variables. For the complete tree mode the number of payoffs calculated depends upon the number of sites being evacuated (NSEI), the maximum number of transmission options for each site (MNTR), the maximum number of plant types to be considered (MNT) and the maximum number of cooling alternatives (MNC).

For the individual payoff claculations the control flags are specified previously. Only two maximum bound flags (MNTR, NSEI) must be input for this calculation option.

The program will process calculations for any number of sites. The program treats each site as a separate case. Either a complete set of alternative payoffs or a single payoff can be calculated for one site.

Subroutines SITE and PLANT are input routines. The subprogram names describe the functions of each subprogram. All variables with respect to the site to be valuated are input to the calculation via the SITE routine. Input blocks, $ CØNFLG, $INPUT, $ WATRV and $VARAMB in addition to the two title cards, are handled by this subprogram. Control flag and site related data are input to common blocks for access by the calculational routines. The listing of input data is controlled by the IØØ flag. For short form output (IØØ = 1 or 2) the input data is not listed.

Subroutine PLANT handles all data relevant to the type of power plant being evaluated. Power plant data may either be input or internal. Two complete internal sets of power plant input data are provided. For NT = 1 and IPF = 0 a representative set of light water reactor type parameters are available. For NT = 2 and IPF = 0 a representative set of coal-fueled plant parameters are available.

Following the input section of PLANT are data conditioning and checking routines from Dynatech (1971). Printing of generated values is controlled through the use of the IØØ flag. At the conclusion of the plant subroutine sufficient information is available for transmission calculations. The transmission calculational routine TRANS is called as the final action of PLANT.

Length of transmission lines is a significant parameter in the determination of system costs and efficiencies. Transmission calculations are treated in two discrete pieces. A new construction distance DISTR (I)) is used to treat the length of new transmission lines (in miles) that must be added to the existing network in order to accommodate the new plant and its added generation capacity. With respect to the new construction distances the following parameters must be available for use in determining capital and operating costs of the new lines for every transmission option I.

Variable	Definition and Units
CCPM(I)	Capital cost of new lines (\$/MI-1000MW)
YØPCM (I)	Yearly Operation and Maintenance Cost (\$/MI-1000MW-YR)

The fixed charge (.81 \$/KW-YR) and the TMCST (I) value can be adjusted to fit the nature of the grid under study. The total transmission cost is the sum of the new construction and load center related costs.

TRCST = TPEM + TC

Land use by transmission lines represents another significant parameter relevant to the siting of thermal power plants. Land use is calculated using data obtained from McIntyre (1970). Using 500 KV as a transmission voltage, a right-of-way 150 feet wide is required for transmitting 1000 to 1500 MW of power. Land used is then classed into new construction (SPNC) and grid (SPTR).

SPNC = (DISTR(I)*150.*5280.)/43560. (ACRES)

SPTR = (DISLC(I)*150.*5280.)/43560. (ACRES)

Cooling calculations are based on the slightly modified cooling calculation package written by Dynatech (1971). A dummy routine CØØLING is used to call the appropriate cooling routine depending upon the value of the cooling index (NC). The options available are:

NC = 1, once-through cooling

NC = 2, artificial cooling poind

NC = 3, mechanical draft evaporative cooling tower

NC = 4, natural draft evaporative cooling tower

The logic of all Dynatech cooling routines is similar. Calculation is started at the minimum condenser operating temperature. For systems with a specified set size condenser the approach temperature is incremented until the maximum condenser temperature is reached. For systems designing both condenser and cooling device for a recirculating system, the program increments both condenser and approach temperatures to determine the minimum cost system. Design of topping systems for a system with a fixed condenser is a one stage process with condenser temperature determined by trial and error to obtain the design outlet temperature. Topping systems that contain a condenser design are iterated until a maximum condenser temperature is obtained. For all systems the least cost system is the design output. For the backfitting case (condenser specified) with topping operation only one system is evaluated.

Three basic screening configurations are available for power plant use:

1. basic intake only
2. rotating/self-cleaning screens
3. infiltration beds

For this work the basic intake system was taken to be that which was necessary to withdraw water from the environment and protect the plant machinery and piping from damage that might be caused by ingested objects, living or inert. This intake system design does not protect fish only plant components.

Two design options are available in the current model:

NSC = 1, basic intake structure only

NSC = 2, rotating screens installed.

Screening cost functions have been developed. Costs are a function of the intake flow rate. The costs are taken to be the sum of a fixed factor plus a flow dependent term.

$$CC\emptyset STS = F1 * FLOI + F2 \quad (\$)$$

The screened flow rate (FLØI) is in cubic feet per second (cfs). The values of F1 and F2 are a function of flow rate and are illustrated in Table 17. The cost per unit power generated is:

$$CCPUP = \frac{CC\emptyset STS*ANFCR}{PSIZE*1000.*CAPFAC*8.76} \qquad \text{(mills/kWh)}$$

Operation and Maintenance yearly costs are taken to be ten percent of the capital costs

$$OCPUP = \frac{0.01 * CC\emptyset ST}{PSIZE * 1000.*CAPFAC*8.76} \qquad \text{(mills/kWh)}$$

The total cost to the plant is the sum of the two unit costs. Fish damage from intake into the plant is considered to be zero.

Intake-only costs are valued at sixty percent of system costs with screens.

$$X2 = 0.6 * CCPUP$$

$$X3 = 0.6 * \emptyset CPUP$$

Flow Rate (cfs)	F1 ($/cfs)	F2 ($)
FLØI ≥ 500	240	0.0
10 ≤ FLØI < 500	1000	0.0
FLØI < 10	0.0	8000

Table 17. Screening Cost Factors as a Function of Flow Rate

An intake damage function is constructed for the intake without screens. The damage function assumes that the percentage of fish damaged is proportional to the percentage of river flow withdrawn by the plant. The value of the resident fishes in dollars per year is assumed to be known and input. This valuation should reflect both commercial and sport fishery elements.

$$DAM(age) = \frac{FISH*FL\emptyset I}{QFLRIV} \qquad (\$/YR)$$

Using this relation a first approximation to the impact of a non-screened plant can be determined. A benefit/cost ratio may be constructed if desired. The benefits would be damage prevented. The costs are the difference between the intake only costs and the screening system costs. This formulation assumes that all fish damage is prevented with the installation of the rotating screens.

Chemical discharge costs are calculated in this version of the code. Current options are no treatment (NCH = 1) and treatment (NCH = 2). Costs involved are calculated on estimated treatment procedures and are based on the cost estimates of Smith (1967).

Discharged effluents contain original chemicals from the intake water plus chemicals added to protect plant components. The concentration of the original chemicals is increased with the use of a closed-cycle cooling system through water loss to evaporation (cycles of concentration). On a total solids basis the amount of original chemicals remains roughly the same with system losses occurring due to deposition of material in the cooling system, blowdown, drift and windage. Added chemicals are assumed discharged at their operating concentrations. Nonconservative chemicals such as chlorine may be removed from the system or reduced in concentration through the scrubbing action in the system tower or biologic uptake by resident biota in a cooling pond. Disregarding reactions in the relative short residence time within the system, once-through cooling systems do not modify the natural chemical content of the water used for cooling. Chlorination in once-through systems was discussed in the baseline section. Mechanical condenser cleaning would not involve addition of chemicals. Removed material that was not collected and treated would be discharged to the receiving water.

The subrountine PAYØFF calculates the air, water, solid waste, and land use impacts and an itemized total system cost for the set of alternatives specified. For each plant type at a site there are sixteen identified alternative decision paths per transmission alternative.

Air impacts of the plant are specified by fuel type. Coal emissions from Duprey (1968) were used for emissions. The calculation gives emissions for the base heat rate condition plus the perturbation effects (if any) on the air emissions from non-once-through cooling means. Nuclear emissions are not closely tied to the heat rate value and are estimated at 0.238 microcuries/kWh.

Water impacts of the plant are specified as a function of cooling means, screening and chemical discharges. Tables of fish community response for the six representative rivers evaluate the thermal status of the community with respect to before and after the presence of the plant.

Land use impacts represent the total acreage used for plant, cooling and transmission. Each component is itemized.

Cost factors are output with respect to the capital costs involved at each decision level plus the cost per unit power production (mills/kWh).

Solid waste impact is keyed to fuel residues from the fossil fired plant. Information from Duprey (1968) and Baumeister (1958) was used to obtain a value of 0.24 lb/kWh for ash and other solid matter resulting from fossil fired combustion. This value is increased as the heat rate increases. Nuclear fuel presents no on-site solid waste problem as its processing is handled in a separate area.

The payoff calculation is presented in a two page summary form that gives the above information without the detailed results of the sublevel calculations. This output form makes the program more desirable for remote terminal acess.

COMPUTER MODEL - Input Data

This section describes the input data necessary to run the static siting model. It is not a complete listing of all variables contained within the program. The term data card and information line will be used interchangeably in the text. A complete listing of the input values, names and units is described in the following section of text. With the exception of title cards and the tree print-out control card. All data is input via NAMELIST. This input method is standard on most FØRTRAN IV compilers and eases the field counting problems encountered when using standard, format-dependent input statements. The problems of counting spaces and setting tabs are alleviated with the NAMELIST input procedure. The input quantities are now described in the order in which they are used by the program. Figure 10 is a sample data set.

Variable	Definition	Permissible Range
NS	Number of site being analyzed	1 to 4
NSEI	Total number of sites to be analyzed	1 to 4
NTR	Number of transmission options for site (NS)	1 to 5
NT	Plant type designation number: 1 = Water Reactor 2 = Fossil fueled	1 or 2
MNT	Number of plant types to be evaluated for sites (NS)	1 to 2
NCØ	Cooling System Code Number 1 = Once-Through 2 = Pond 3 = Mechanical Draft Wet Tower 4 = Natural Draft Wet Tower	1 to 4

```
2

 $CONFLG NS=1,NSEI=1,NTR=1,MNTR=1,NT=1,MNT=1,NCO=3,MNC=1,NSC=2,NCH=1,

 IPF=0,ICF=1,IOO=2 $

SAMPLE DATA INPUT CASE FOR SITING PROG.

PLANT ON RIVER CLASS NO 1

 $INPUT TDB=90.,TWB=73.,WIND=8.,RAD=5200.,PRPAGR=1000.,NTAMB=4,ACC=2.,

 CONSCT=5.,YOPCM(1)=325.,TMLS(1)=0.0005,TMCST(1)=0.01,ANFCR=0.10,

 CCPM(1)=300000.,DISTR(1)=15.,DISLC(1)=150. $

 $WATRV QFLRIV=150000.,WIDTH=1000.,DEPTH=10., TAVH2O=66.,NH2O=0,

 FISH = 6000000., NR=1 $

 $VARAMB TAMDB(1)=95.,29.,80.,40.,TAMWB(1)=75.,20.,45.,33.,TAMRV(1)=68.,

 60.,67.,60.,AMWIND(1)=6.,20.,8.,7.,AMRAD(1)=5600.,2140.,5500.,1000. $
```

Figure 10. Sample Data Set for Static Stiting Model

MNC	Maximum number of cooling alternatives to be evaluated	1 to 4
NSC	Screening alternative code 1 = No environmental screening 2 = Environmental screening	1 to 2
NCH	Chemical treatment alternative code 1 = No chemical treatment 2 = Complete chemical treatment	1 to 2
IPF	Power plant input factor 0 = Program uses internal power plant data 1 = Power plant data in input	0,1
ICF	Program control mode 1 = Individual payoff calculation Any other value full tree mode	0,n
IØØ	Output option control =1 Only payoff values output =2 Level calculations and payoff values output =3 Input data, level calculations and payoff values output	1 to 3
MNTR	Total number of transmission paths to be evaluated for Site (NS)	1 to 5

The first value input is the control flg (ITO) for printing out the tree display. The format for ITO is I1. A value of 3 causes the tree to be displayed. Any other value entered (including 0 or a blank card) will defeat the printing of the tree. It utilizes almost the full width of the line printer and is not cropped to the 72-column width requirement of a teletype terminal. Therefore, ITØ must not be set equal to 3 for remote terminal use. A copy of the tree may be kept with the input instructions for ready reference.

The first NAMELIST input block is named CØNFLG. This input block contains the information that controls the calculational sequences. All input values in this block are integers. When using the NAMELIST input routine, it is not necessary to input variables in any particular order. The tree printout (Figure 11) can be referred to as an aid in selecting individual payoff calculation input controls. The tree shows the range of options

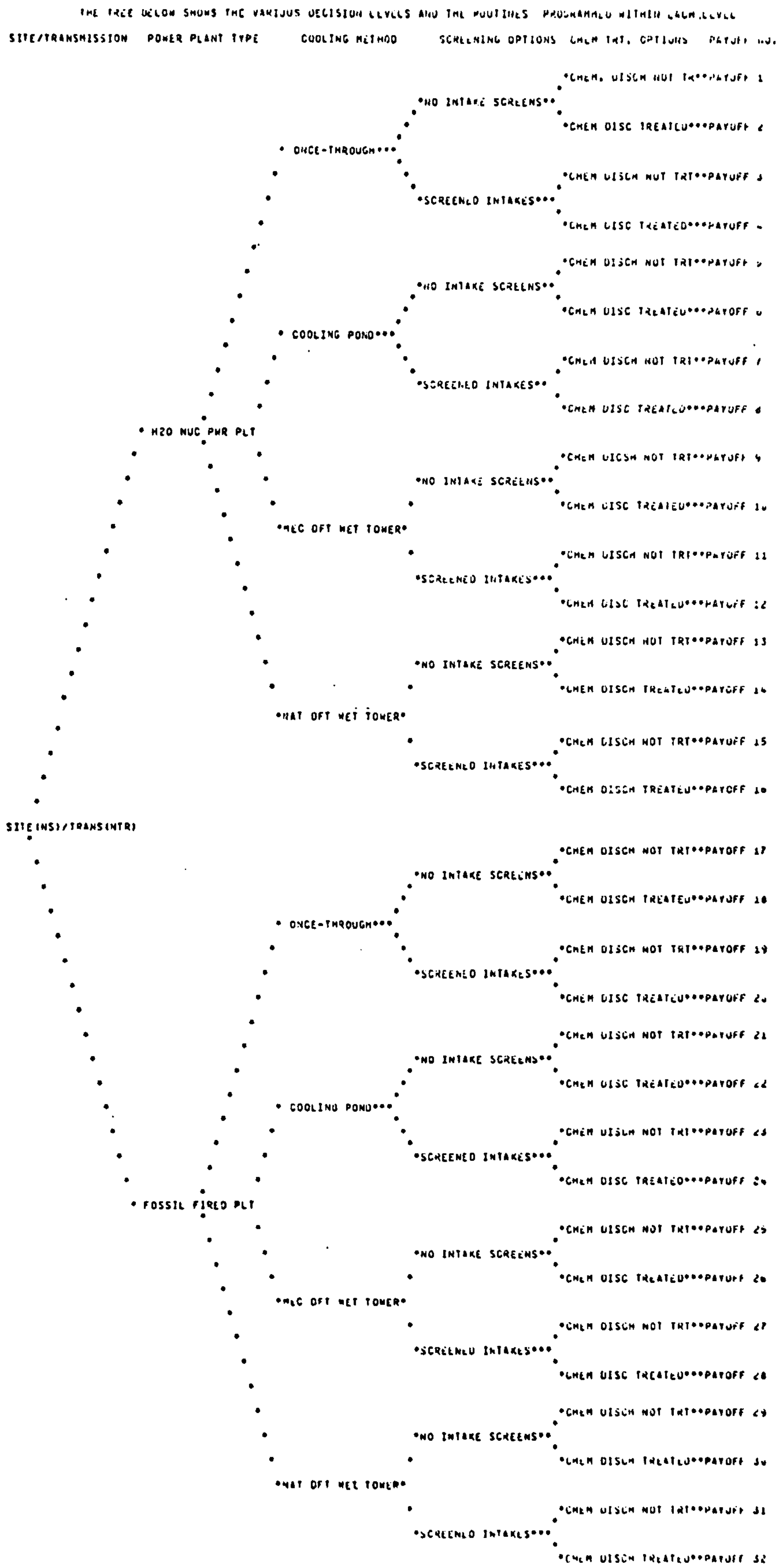


Figure 11. Static Siting Model Decision Tree

that are available.

For an individual payoff calculation concerning a particular site, plant type, cooling system, screening alternative, and chemical treatment process, all of the above variables must be input with ICF equal to one. With ICF equal to one the internal call sequence for alternative combination generation is defeated. When this is accomplished, values for NS, NTR, NT, NCØ, NSC, and NCH, which are usually internally controlled, must be supplied as specified above. For a complete tree evaluation these values must not be input.

Output option control is provided to shorten the printed output for remote terminal use. The entire tree contains 32 discrete payoff calculations in its present form. Thus, if the tree were evaluated in its entirety with input data and level calculations, a teletype unit would become output bound and non-optimally utilized. Lengthy runs may be submitted remotely and channeled directly to the central computer line printer. For remote terminal output individual payoff calculation mode (ICF = 1) and shortened output IØØ equal 1 or 2 are recommended.

The next two cards are title cards. The first forty spaces on each card are utilized. Any characters may be entered including blanks. For example, the first card may contain a plant name and the second card the site location.

The next NAMELIST input block (input) is for variables specifically related to the plant site. All of these variables are required input for complete program execution. Variables input are:

Variable	Description	Range and/or Units
TDB	Design dry bulb temperature for cooling systems	°F
TWB	Design wet bulb temperature for cooling systems	°F

WIND	Design wind speed	m.p.h.
RAD	Design net radiation	Btu/ft^2/day
PRPAGR	Land cost	$/Acre
NTAMB	Number of alternative ambient operating conditions	0 - 4
ACC	Accessibility parameter for adjustment in base plant cost due to moving of major material and components	0 - 100 (% of base cost)
CØNSCT	Escalation parameter for adjustment in base plant cost due to local labor costs	0 - 100 (% of base cost)
YØPCM (I)	Yearly operating cost of transmission lines on Ith path	$\frac{\$}{\text{MI-YR-1000 MWe}}$ I=1, MNTR
TMLS (I)	Fraction of power lost per mile transmitted on Ith path	$\frac{\text{fraction lost}}{\text{mi}}$ I=1, MNTR
TMCST (I)	Transmission cost	$\frac{\$}{\text{1000MW-YR-MI}}$
ANFCR	Fixed charge rate for plants at this site	% x .01
CCPM (I)	Capital cost of new transmission lines on Ith path	$/1000MW-MI (I=1, MNTR)
DISTR(I)	New construction transmission distance for Ith path	mi (I=1, MNTR)
DISLC (I)	Load center distance (total including DISTR (I)) for Ith path	mi

Input values specifically pertaining to the native water body are input in the NAMELIST block WATRV. All variables in this block are required input.

Variable	Description	Range and/or Units
QFLRIV	Design river flow rate	c.f.s.
WIDTH	Design river width	ft.
DEPTH	Design river depth	ft.

TAVH2Ø	Design available river temp.	°F
NH2Ø (Integer)	Available water type = -1 salt water = 0 untreated freshwater = +1 treated freshwater	-1 to 1
FISH	Yearly capital value of fish at site (including transient and resident populations)	$/yr.
NR	River classification index = 1 Columbia River = 2 Sacramento River = 3 Upper Mississippi River = 4 Lower Mississippi River = 5 Tennessee River = 6 Delaware River	1 to 6

Next follows the NAMELIST input block VARAMB. VARAMB is the input data block of the evaluation of the design plant at the various operating conditions at the site under consideration. The entering of this data block into the input information is optional. The program will only seek this data block if NTAMB is greater than 0. If NTAMB is equal to 0, this data block must be omitted from the input string.

The variables are input in sets with incident radiation, dry bulb temperature, wet bulb temperature, wind speed, and available water temperature needed to comprise an input data set. The variables are divided into sets by the storage index. Variables stored in these arrays should be keyed into sets based on the storage index value (e.g. all variables in the first set entered as the first element in their respective arrays).

Variable	Description	Range and/or Units
TAMDB (I)	Dry bulb temperatures (I=1, NTAMB)	°F
TAMWB (I)	Wet bulb temperatures (I=1, NTAMB)	°F
TAMRV (I)	River water temperature (I=1, NTAMB)	°F

AMWIND (I)	Wind speeds (I=1, NTAMB)	m.p.h.
AMRAD (I)	Net over-water radiation values (I-1, NTAMB)	$\frac{\text{Btu}}{\text{ft}^2/\text{day}}$

All of the following NAMELIST input blocks pertain to internal steam plant detailed operating characteristics. If IPF = 1, all must be included. If IPF = 0, all data blocks must be omitted. The namelist data sets will be discussed in order of their appearance should they be included. All variables listed must be entered for proper program execution (except as noted under $ SYSDTA). The variables listed under their namelist block names are:

Variable	Description	Range and/or Units
$ PLPARM		
PSIZE	Plant electrical output	Megawatts (MWe)
CCPKW	Plant capital cost	$\frac{\$}{\text{kW}}$
FUCST	Fuel cost	¢/10^6 Btu
SPGR	Land needed by steam plant (excluding cooling and transmission facilities)	Acres
NCAPS (integer)	Number of plant operating capacities	1 to 6
$ CATURL		
CAP (I)	I^{th} design operating capacity (1 to NCAPS)	1 to 6
TØTLD (I)	Number of hours spent @ CAP (I). Must total to 8760 hours (1 year).	hours
CØLPCT (I)	Fraction of time cooling system is in use for CAP (I)	0.→1.
NHRPTS (I) (integer)	Number of turbine heat rate points input for CAP (I) Minimum is 3; maximum is 6	3 to 6
PCMIN (I)	Minimum condenser operating pressure for CAP (I)	in Hg.
PCMAX (I)	Maximum condenser operating pressure for CAP (I)	in Hg.

$ TURØPD

HRP (I,J)	Condenser pressure (I) corresponding to TURBHR (I) for capacity J	in Hg.
TURBHR (I,J)	I^{th} turbine heat rate for I^{th} capacity, minimum of 3 for each J	$\frac{Btu}{kWh}$
PCBASE	Base design condenser pressure	in Hg.
PCTAMB (I,J)	Fraction of time spent at I^{th} capacity for J^{th} ambient condition. Sum over J must equal 1.0 for every I.	0.0→1.0

$ SYSDTA

NSYSØP (integer)	System operating flag = 0 Closed cycle operation = 1 Cooling system is of helper design (once-through base)	0, 1
NSPCØN	Condenser design flag = 0 Condenser is designed internally = 1 Condenser is specified by the following data	0, 1
UØVALL (optional)	Heat transfer coefficient Input only if NSPCØN = 1	$\frac{Btu}{hr/ft^2/°F}$
AREAC	Condenser area. Input only if NSPCØN = 1	ft^2
SPFLØW	Condenser flow rate. Input only if condenser is specified (NSPCØN = 1)	$\frac{lbm}{hr}$

NAMELIST input blocks have a few basic rules. Column one must always be left blank. The NAMELIST block name is the first entry starting in column two. The proper entry is $NAME with no imbedded blanks. One blank space is left between the name and the first data entry (e.g. $NAME A = 1.,). Each input value is separated from the next with a comma. Each line of information (data card) must end with a complete record (e.g. A = 1, or Z = 100._$). The last value input is followed by one space and a dollar sign indicating the end of the NAMELIST block (e.g. Z = 100._$). Variables may be input in any order desired.

SECTION V

DYNAMIC ASSESSMENT

Incremental decision making is a symptom of our society. The fragmentation of decision making, the market mechanism that ignores externalities, and the lack of adequate feedback mechanisms permit rational appearing incremental decisions to become a chain of events with sufficient intertia that environmental degradation cannot be avoided without major societal changes. Many water pollution problems were not the result of initial decisions to locate waste discharges, but the result of the magnetic attraction of development for other development with accompanying increases in waste discharges. Another aspect of incremental environmental decision making is the satiating factor where "too much of a good thing" can create environmental damage. In the Pacific Northwest the hydroelectric projects on the Columbia River are at a satiation point from both a physical and an environmental standpoint. Future power generation must come from thermal systems.

The static model developed for this study is an incremental decision making tool. It does not address the questions of established precedence of a siting decision, nor the subsequent options that such a decision may eliminate, nor any of the problems cited above. While it is naive to think that a perfect model of the future can be developed or that a twenty year plan for thermal plant locations can be constructed without periodic updating, it may be possible to examine alternative futures and select a siting pattern that is least sensitive to social change.

The goal of the dynamic assessment effort in this study was to evaluate methods that permit the examination of a sequence of siting decisions rather than just the impact of a single plant location. Questions that were addressed included:

1. Given that n plants must be located in a region in t years, identify the sequence of sitings that minimize environmental impact.

2. Will an incremental optimal siting decision now create irreversible conditions that preclude optional siting in the future?

3. How sensitive is a given site location to alternative patterns of urban and industrial growth in a region?

4. What are early warning signals that indicate current siting patterns will create serious environmental impacts in the future?

Models for Dynamic Assessment

A major concern of siting models is that they are severe abstractions of the real world which contain so many assumptions that all reality is lost. In this study, each model was studied to determine what real world conditions were simulated and what assumptions were necessary. Since the focus of the dynamic assessment was time variance, this was given greater value than specific static details concerning power plant performance. Three different dynamic models were studied for applicability to the thermal siting problem; the linear-programming (LP) transportation model, the Forrester-"dynamics" models; and dynamic programming. Each model was constructed for a 20 site system and a 20 year time period.

The linear programming-transportation model addresses the problem: given i generation sources and j load centers, and a demand for service as a function of loads, determine the optimum assignment of sources and load centers over time. The model requires as input the cost to generate and transmit power from i to j, C_{ij}, the demand at each j, D_j, and the maximum source capacity for each i, S_i. The linear programming algorithm will allocate the power from sources to the sinks, P_{ij}. The mathematical model is written:

$$\text{Min. } \sum_i \sum_j C_{ij} P_{ij}$$

Subject to the constraints that

$$\sum_i P_{ij} \geq D_j$$

$$\sum_j P_{ij} \geq S_i$$

Obviously this model lacks a time variable and cannot be used directly as a dynamic model. Two modifications are possible; (1) let j represent time rather than space, so that D_j represents load demands at different time periods, or (2) add a subscript k to represent time periods. The first modification sacrifices spatial resolution of load centers, but does introduce the time variable. The second modification increases the number of variables geometrically and presents a serious computational problem. Both require the introduction of a constraint establishing the maximum power generation at each source for each time period. All linear program formulations impose an abstraction that the cost functions are independent of power produced or transmitted (no economy of scale). This constraint can be avoided by repetitively processing the model employing different coefficients until the cost coefficient and magnitude of power P_{ij} are correct, but this can be very time consuming. The advantages of the linear program are that standard computer programs exist to process the model, there is minimal input preparation, and sensitivity analysis can be easily obtained. The disadvantages are that demand and supply are independent and no feedback can be represented. The model cannot be made to relate increased supply at a point to increased power demand or to increased cost of producing power. One would expect power costs to increase in aregion as more development occurs or population increases. The linear program cannot provide an abstraction of these interactions.

An example of the dynamic assessment of power plant siting using linear programming is shown in Figure 12. Very complex models are costly; for

Objective Function:

Minimization of total costs

$$\sum_i \sum_j C_{ij} P_{ij}$$

Constraint Equations:

Demand must be satisfied

$$\sum_i P_{ij} \geq D_j$$

Power produced at site i and time j must not exceed the maximum capacity of site i

$$\sum_j P_{ij} \geq S_i$$

Water interaction limitation factor

$$\sum_i \sum_k w_{ik} P_{ij} \leq W_j$$

Air interaction limitation factor

$$\sum_i \sum_k a_{ik} P_{ij} \leq A_j$$

Transmission limitation path

$$\sum l_{ij} P_{ij} \leq L_j$$

Where:
- i = site index
- j = time index
- k = dummy site index
- C_{ij} = cost to produce and transmit power from site i at time j
- P_{ij} = Power produced at site i and time j
- D_j = Power demand at time j
- S_i = Power production capacity of site i
- w_{ik} = Water quality interaction coefficient between plants i and
- W_j = Water quality limit at time j
- a_{ik} = Air quality interaction coefficient between plants i and k
- l_{ij} = Transmission line area per unit power factor from site i at time j
- L_j = Total amount of land available for transmission at time j

Figure 12. Linear Programming Formulation

example, Watt at UC Davis is funded for over a million dollars to create such an energy model.

An example model using Forrester's concept with a linear programming optimization imbedded in the structure was constructed for evaluation. The model considered the power demands and generating capacities for the PNW power supply areas in Washington, Oregon and Idaho using the following variables in each region:

Power loads
Power generation
Population
Power cost
Environmental quality

Figure 13 defines the cause-effect relationships included in the model in matrix form and Figure 13 translates the matrix into flow graph form. A transform must be defined for each arrow in the flow graph and these transforms can be programmed for the computer. Initial conditions are defined for each parameter at the initial time period; these values are used in the program to compute new values at the next time period. For example, the population in region J can be expressed as:

$$\Delta POP(J,T) = POP(J,T-1) * K(J)EQ(J,T-1) * [KPOP(J) - POP(J,T-1)]$$

where $\Delta POP(J,T)$ = change in population of region J at time T
$POP(J,T-1)$ = population of region J at time T-1
$K(J)$ = annual rate of population growth
$EQ(J,T-1)$ = quality of environment of region J at time T-1
$KPOP(J)$ = maximum population desired in region J

This transform indicates that the population increase is a function of the existing population times a growth constant, times a correction for limiting growth. Such a function is commonly used in population dynamics. Dynamic models of this type permit <u>flexibility</u> in modifying transforms and

	Power Load	Power Generation	Population	Power Cost	Environmental Quality
Power Load (PL)	1	1		1	1
Power Generation (PG)	1	1		1	1
Population (POP)	1		1		
Power Cost ($P)	1			1	
Environmental Quality (EQ)			1		

Figure 13. Interaction Matrix Within a Region

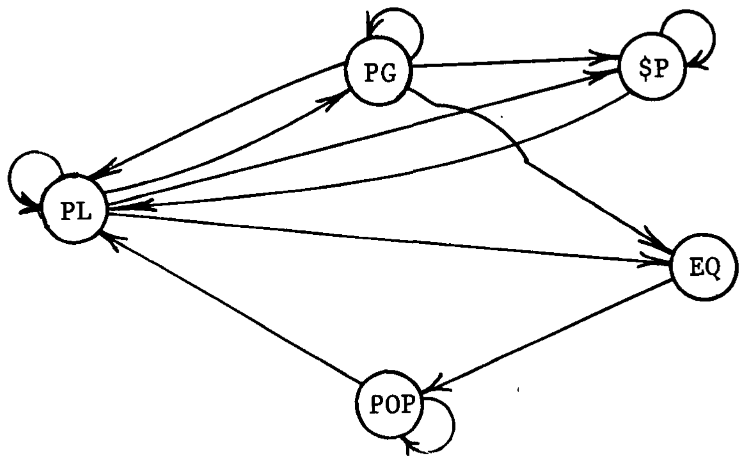


Figure 14. Flow Diagram Based on Interaction Matrix

cause-effect relationships. The purpose of these models is to test the sensitivity of the system to various assumptions concerning transforms. If the matrix in Figure 13 is not acceptable, it can be easily changed and the model reevaluated. For example, if one feels that environmental quality should directly impact power cost, this can be introduced by modifying the statement defining power cost.

In the example model the linear program has been imbedded by computing the power load at time t and employing the power generation values of time t-1 for each sector. These values define D_j and S_i for the linear program (see p. 116) and the optimization of new power units and transmission can be performed using an LP. The cost functions for each region were defined as constant for each type power source. Figure 15 shows a typical cost function. The step increments A, B, C, D indicate the maximum incremental power that can be supplied in this region by a particular type of power generation system. Again the purpose of this type of model is to explore the impact of assumptions concerning the values in the transforms. Variation of costs and limits can be simple model changes. A program listing, sample input, sample output and list of variables for this model are presented in Appendix C.

The major criticism of these types of models is the lack of resolution. Notice that in the population transform there is no definition of age, sex or income structure. Many would argue that each of these additional variables have significant impact in a model and cannot be aggregated. Proponents argue that the purpose of gross models is to demonstrate the complex interactions of such gross concepts. (Looking at forests rather than trees.) For the purpose of dynamic assessment of power plant siting, this method does provide a rapid method to examine the gross system structures and to test assumptions concerning such structure. Any criticism can be incorporated as a model modification to test its validity. The model can continually be adjusted with minimal effort to reflect the

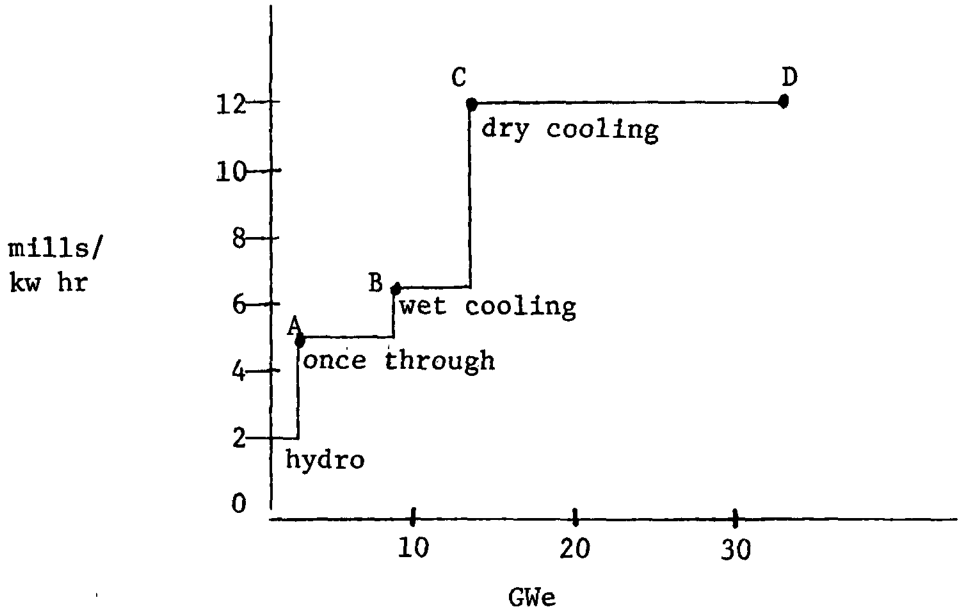


Figure 15. Typical Cost Function for Dynamic Model

current state of knowledge.

The final method examined for dynamic assessment of power plant siting was dynamic programming (Bellman, 1957). This concept has been extensively used to optimize sequential decision making. Using an example of a region requiring 20 new power generating sources in the next t years, the dynamic program assessment can be formulated as follows:

1. The first decision is to select which of the 20 plants to construct.
2. Depending upon this choice the regional demands, economy, population and social values may change. This change may depend on which plant is selected.
3. These changes may in turn change the costs for the remaining 19 plants, so new estimates must be made based on the first decision.
4. The choice is made for the next plant to be constructed, and steps 2, 3 and 4 repeated.
5. The problem is to find the proper sequence of plant installation to minimize power costs, environmental impact or other parameters of interest.

Using the preceding methods of linear programming, dynamic modeling and the static siting model, the analysis outlined could exhaustively be made by the following algorithm:

1. Use the static siting model (SSM) to evaluate the costs for each of the 20 sites
2. For each site use the dynamic model to estimate the change in conditions that would affect the construction of the remaining plants
3. Use these new conditions and the SSM to evaluate costs for the next site selection
4. Repeat

These data can be placed in a decision tree with the construction costs determined by the algorithm representing the pay off at each node (Figure 11). By assuming that each site can accommodate only one plant the tree will converge so that the 20th decision will be deterministic (only one plant is left). If this assumption is not made there will be 20^{20} nodes to evaluate in order to define the optimum path. In order to reduce the number of evaluations one can use the theorem of dynamic programming: "Given a current state, an optimal policy for the remaining stages is independent of the policy adopted in previous stages." In this definition, a stage is one of the twenty decisions to build a specific plant, and a state is the number of existing plants. For example, in the 20 plant problem, at stage 1 the decision to be made is what plant to build, with the system in its original condition. Once the decision is made, the state of the system becomes the original plus the selected plant (20 possible). At stage 2, the decision required is which plant to add given the system in the new state. This simplifies the problem from evaluating 20^{20} paths, each 20 nodes long to evaluate 20 stages with 20 states, but each equivalent path is 2 nodes rather than 20 nodes long. The problem is reduced to a simple case of cost minimization of each point in time using the SSM to generate the costs. If costs are time dependent, the computation process would be too complex to practically apply given the varying quality of input data.

SECTION VI

EVALUATION

The models developed in this study have emphasized the overview rather than the specific. This strategy immediately will draw concern from most readers who concentrate on only one aspect of the siting impact assessment, since the models will not contain the resolution and richness that is desired. The purpose of the models developed in this study were to provide, for the specialist on any aspect of plant siting, an insight into the remainder of the system, and the impact his evaluation of alternatives will have on the total system. The goal was to distill from specific models of system components, those essential features that would strongly influence other components.

One of the most significant concepts used in this study was the hierarchical order of decisions used in power plant development. This order of decision indicates which decision can still be changed after previous decisions have been made, and which cannot. The analysis of siting problems with such a hierarchy is independent of the resolution of data used in the decision making. If the level of information developed in this study is inappropriate, other data can be substituted without modifying the analytical framework.

In each section of this report, the need for model verification has been stressed. The models developed in this study are gross, and in many cases data were found to be proprietary so model refinement was not possible. In other cases, the model resolution was designed to be intentionally gross to be compatible with other segments of the model. Each user of these models should examine the components of the siting problem that he is familiar with and ask "Given the resolution specified is the model an adequate representation?" The resolution of the developed models was established by financial and informational constraints. Limits of resolution can be modified by relaxing these constraints.

The principal application of this model is to explore alternatives and to obtain relative rankings of potential alternatives that should be explored. If higher resolution components were placed in the analytical framework, the models could be used for preparation of detailed impact statements.

SECTION VII

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SECTION VIII

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SECTION IX

GLOSSARY

Acclimation temperature (°C or °F) - The temperature to which an organism has become adapted thru prolonged exposure.

Approach temperature (°C or °F) - The difference between the outlet temperature of an evaporative cooling device and the wet bulb temperature of the surrounding air (theoretical cooling limit).

Benefit-Cost analysis - A technique used to evaluate the economic feasibility of a project. Includes in analysis all benefits and costs in an effort to determine best allocation of monies to project or set of projects designed to achieve a given goal.

Biological impact - Change in the aquatic community caused by the state parameter change.

Biomass - Weight (per unit area) of biological organisms under study.

Blowdown - The quantity of fluid discharged per unit time from a recirculating system in order to maintain the desired chemical concentrations.

Break-point chlorination - That minimum dosage of chlorine necessary to form a free residual of chlorine after uptake by ammonia and reducing compounds.

Capital recovery factor - The uniform, end-of-period payment required for the amortization of capital investment (of magnitude one) over n periods. The sum of the sinking fund payment plus interest on the capital.

Community diversity - The ratio of the number of types of organisms to the total number of organisms.

Condenser cooling water - That water flow rate which is circulated through the steam system condenser in order to provide a heat sink for the heat released by the condensing the steam.

Constraint equation - An equation used in a mathematical model which describes a system boundary as a function of a certain combination of system variables.

Constant-sum decision pairs - Sets of variables considered two per time in which both are compared to a given third parameter. The sum of the comparison scores given the comparison variables is required to be a constant value.

Cooling tower - A device used in a recirculating of topping system which transfers heat from the condenser cooling water to the adjacent air mass. It may accomplish this by conductive heat transfer alone (dry tower) or evaporative, conductive and convective heat transfer (wet tower) through the use of a naturally generated draft or a mechanically generated draft.

Cross-elasticity coefficients - Elasticity coefficients related the predicted change in demand as a function of price per unit. Cross-elasticity coefficients are used to describe a change in two related goods that may substitute for each other.

Cycles of concentration - A number expressing the ratio of chemical concentration in a recirculating system to the concentration in the makeup water (X_c/X_m).

Damage function - A mathematical relation giving ecological damage or change as a function of environmental change.

Decision tree - A branching graph ordering and portraying all possible decision alternatives and associated probabilities and payoffs for a given situation.

Discount rate (%/yr) - That value used to reflect the value of sacrificed consumption in capital investment in order to achieve a benefit at some future time.

Drift loss - The time rate of loss of water and associated dissolved and suspended materials from a evaporative cooling tower system due to the velocity of incident air carrying droplets from the packing area.

Economic rent - The maximum profit attainable from a natural resource optimally regulated on the basis of economics.

Exclusion area - The buffer area for a given thermal power plant required to abate the negative effects of that plant.

Externality - In economic terms a non priced or inaccurately priced consequence of the provision of a certain good or service not considered in the analysis of benefits and costs associated with provision of the good.

Feedback model - A mathematical model that utilizes outputs as future inputs in simulating properly system performance.

Annual fixed charge rate (/yr) - That fraction of the original cost which must be paid each year for amortization of investment and for all charges associated with the investment and use of the capital (e.g. depreciation, taxes, insurance).

Fouling - Impediment to heat transfer in a system due to biologic growths, material deposition or surface corrosion.

Hardness (usually mg/ℓ $CaCO_3$) - The measure of the presence of certain divalent cations in natural waters (usually CA^{++}, Mg^{++}, Sr^{++}, Fe^{++}, Mn^{++}). Such ions are capable of procuding undesirable precipitates.

Heat source - In a thermal electric generating station that part of the plant which generates steam for use in the turbine.

Helper tower - A recirculating cooling system only with capacity to dissipate part of the total plant heat load during extreme conditions.

Hydro-environment effects - Those effects on members of the aquatic community caused by a particular event (e.g. temperature change).

Incremental decisions - Decisions that are made in stages or finite part, utilizing information generated from previous decisions in the sequence.

In-plant losses - Those losses of heat that occur within a thermal power plant between the boiler or steam generator and the turbine exhaust. These losses are the difference between the heat added to the system and the useful work plus the heat rejected in the cooling water.

Intake structure - The facility designed especially for removing the power plant's water from the natural water body serving as the source.

Lead time - That time required between perception of a need for more electric power and the actual commencement of planning for delivery of the power at the desired time.

Load center - The hypothetical point where all electric power use is centered. The load center is the point considered as the terminus of the high voltage transmission line facilities and the beginning of the distribution facilities.

MWe - The units of electrical power for the system (megawatts - electrical). As differentiated from thermal power output (MWt).

Objective function - The function relating problem variables that is to be optimized in any optimization problem.

Opportunity cost - The cost associated with use of capital in a project yielding revenue at a future data due to forgone benefits from alternative investments and to forgone consumption.

Payoff - The resultant element that arises from a particular decision or sequence of decisions.

Peak power - Power demanded in excess of the base power load during certain time spans.

Recirculating cooling system - Any cooling system for a thermal power plant that does not involve the direct intake and immediate discharge of the condenser cooling water supply.

Scale - Deposition of dissolved solids from circulating cooling water on exposed surfaces of the condenser cooling water equipment.

Sludge - Those solids separated from water during its treatment by various physical, biological or chemical processes.

TLm - A median tolerance limit for 50 per cent mortality from exposure to the stated substance for the stated time.

Topping system - An open loop cooling system designed to reject only part of the system heat to the atmosphere through either a tower or pond before discharging the remainder to an adjacent water body. The devices used in these systems are termed helper tower or flow-through ponds. These systems remove that part of the heat load that is above the discharge standard.

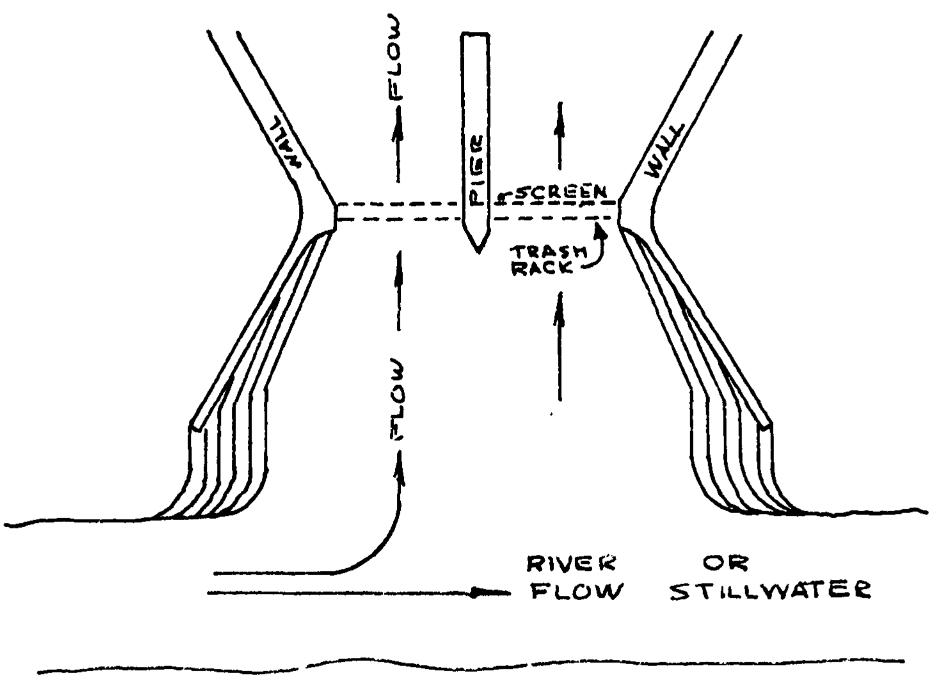
Windage loss - Water loss from an evaporative tower due to lateral wind pressure on the packing. The loss is in droplet form containing system chemicals that are not subject to removal by air scrubbing action.

Wheeling charge - That charge assessed for the transport of electric power over a high voltage transmission system.

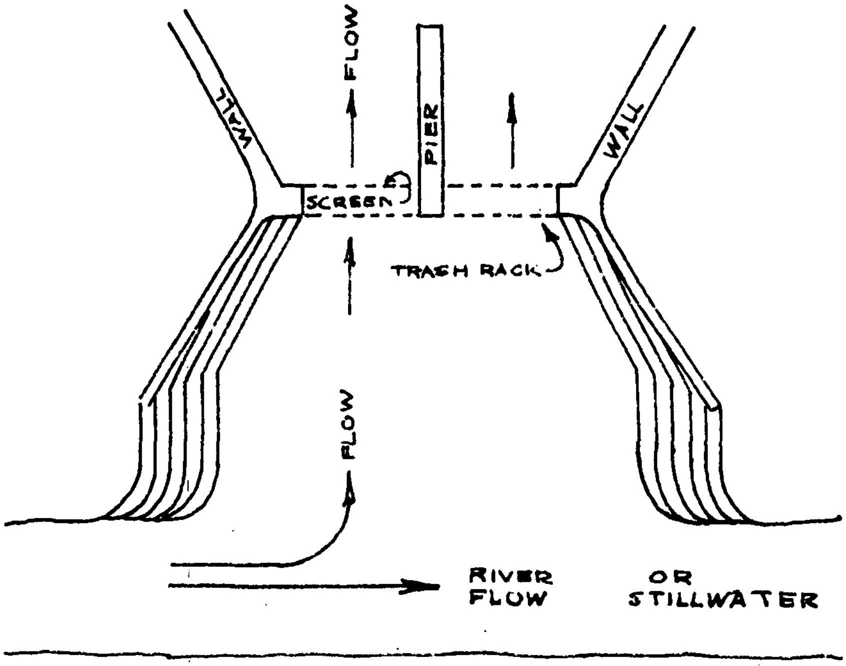
SECTION X

APPENDICES

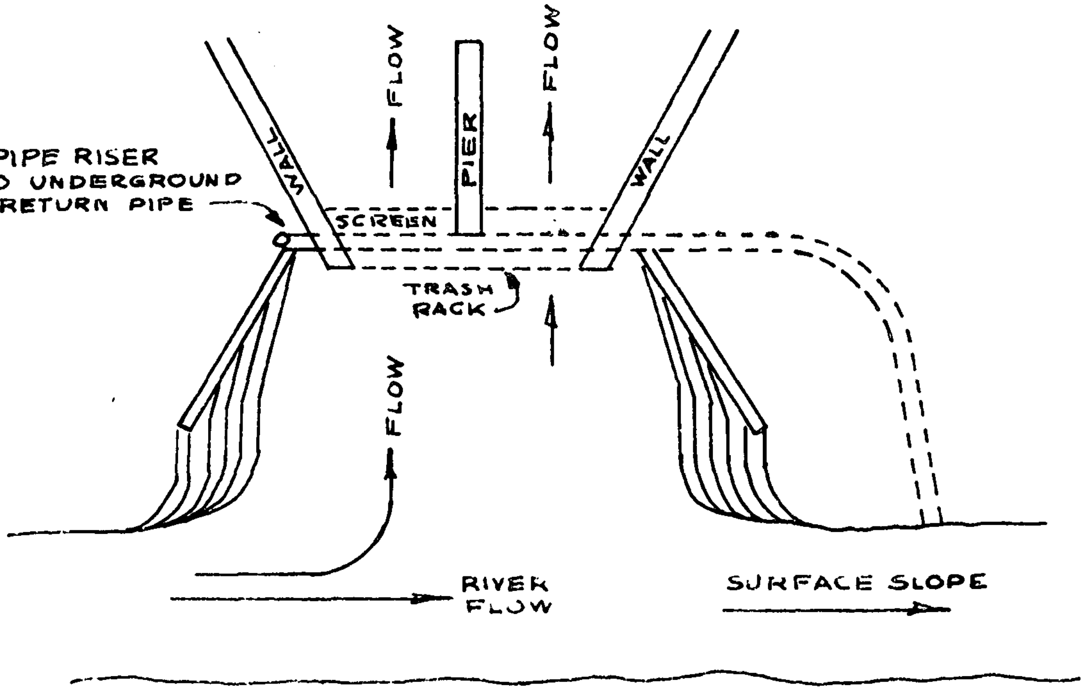
Appendix A. Inlet Screening Configurations



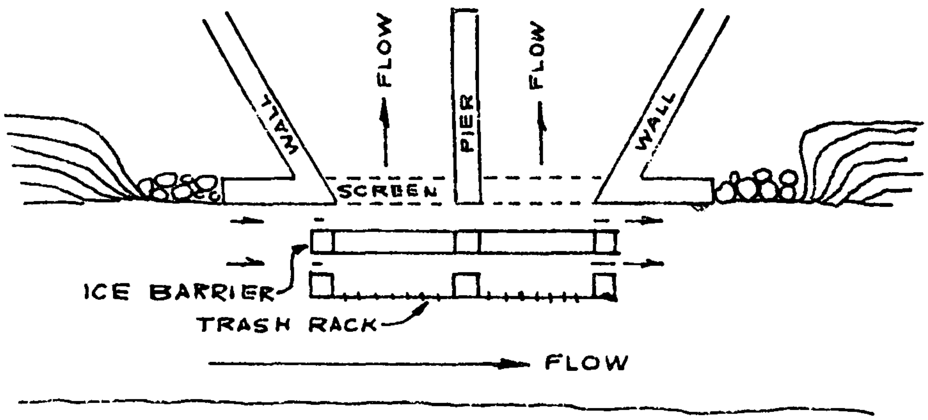
RECESSED SCREEN
NO BY-PASS
POOR DESIGN



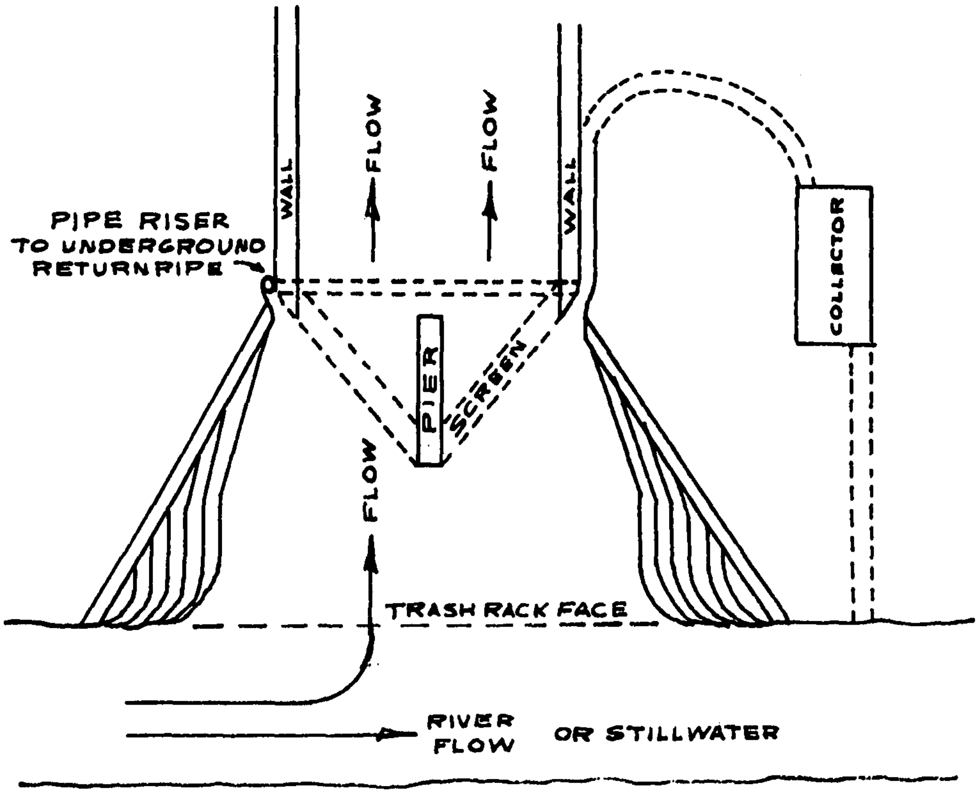
SMOOTH-FACED SCREEN
NO BY-PASS
SOMEWHAT BETTER DESIGN



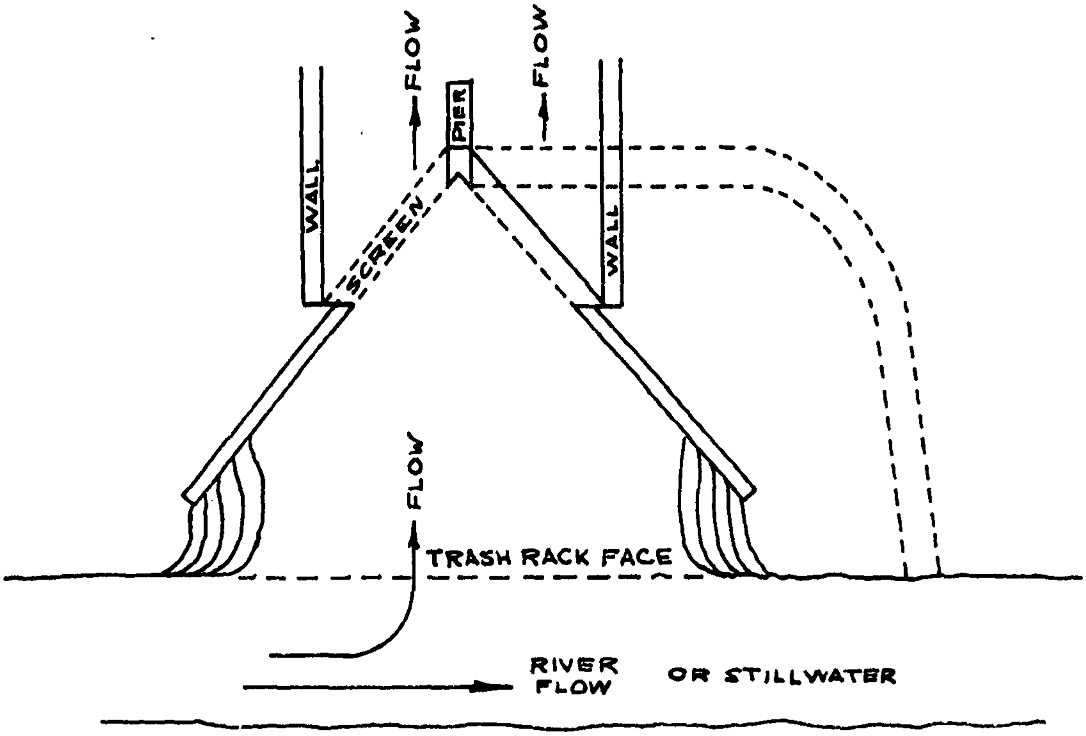
SMOOTH-FACED SCREEN
WITH BY-PASS
BETTER DESIGN



SMOOTH-FACED SCREEN
RIVER BECOMES BY-PASS
BEST DESIGN



ANGLE FACE
WITH BY-PASS
GOOD DESIGN



REVERSE ANGLE FACE
USING ONE BY-PASS
BEST DESIGN

LIST OF VARIABLES

This is an abbreviated list of variables which does not include those previously discussed in the text nor those given in the Dynatech (1971) program.

VARIABLE	DEFINITION
CCØST	Capital cost of new transmission facilities ($)
CCØSTS	Capital cost of screening system ($)
CCSC	Capital cost of cooling alternative ($)
CDIS(I)	Discharged chemical concentration (x inlet)
CFISH	Cost of fish damaged by plant intake ($)
CHSC	Cost of chemical system (mills/kW-hr)
CØNCR	Cycles of concentration
SCS	Cost of cooling system (mills/kW-hr)
DISCH(I)	Water quantity discharged by cooling system (cfs)
LØCI(I)	Storage variable for second title card
NAMES(I)	Storage variable for first title card
PNAME(I)	Storage variable for plant type name
SPCØ	Land required for cooling devices (acres)
SPGR	Land required for base plant (acres)
SPNC	Land required for new transmission lines (acres)
SPTR	Land required for existing transmission lines (acres)
TDIS(I)	Temperature of water discharged from cooling system (°F)
TRCST	Total transmission system cost (mills/kW-hr)
TZERØ	Temperature of river without plant operating (°F)
WATER(I)	Water quantity intake by cooling system (cfs)

```
      PROGRAM BUILD(INPUT, OUTPUT,TAPE5=INPUT, TAPE6=OUTPUT)
C     BASIC DECISION TREE CALL SEQUENCE FOR THERMAL PLANT SITING
C     THIS PART OF THE PROGRAM GENERATES THE VALUES TO BE USED
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOILD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPIR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      READ(5,5) ITO
    5 FORMAT(I1)
      IF(ITO.EQ.3) CALL TREE
      PRINT 11
   11 FORMAT(1H1,*              POWER PLANT SITING ANALYSIS PROGRAM*//)
C     INITIALIZE THE LEVEL COUNTERS
      NS = 0 $ NSE = 0
C      CARD 1 COMMENCES THE ANALYSIS FOR EACH SITE
    1 NS=NS + 1 $ NT=0 $ NTR=0 $ NP=0
      CALL SITE(NS,NSEI,NTR,MNTR,NT,MNT,NCO,MNC,NSC,NCH,NP,IPF,ICF)
      IF(ICF.EQ.1) GO TO 20
      NP = 0
C     STATEMENT 2 COMMENCES THE ANALYSIS FOR EACH TRANSMISSION OPTION
C     CALCULATION IS NOT PERFORMED UNTIL AFTER THE PLANT SUBROUTINE
C     AS TRANSMISSION COSTS ARE A FUNCTION OF BOTH PLANT AND SITE
    2 NTR = NTR + 1 $ NT = 0 $ NCO = 0
C      STATEMENT 3 COMMENCES THE ANALYSIS FOR EACH TYPE PLANT FOR ANY
C      SITE
    3 NT = NT  +1 $ NCO = 0
      CALL PLANT(NS,NTR,NT,IPF)
C     STATEMENT 4 COMMENCES THE COOLING ANALYSIS FOR EACH TYPE/SITE
    4 NCO = NCO + 1
      CALL COOLING(NS,NT, NCO)
      NP = NP + 1
      NSC = 1
      CALL SCREENS(NS, NT, NCO, NSC)
      NCH = 1
      CALL CHEM(NS,NT,NCO,NSC,NCH)
      CALL PAYOFF(NS,NTR,NT,NCO,NSC,NCH,NP,ICF)
      NCH = 2
      CALL CHEM(NS,NT,NCO,NSC,NCH)
      NP = NP+ 1
      CALL PAYOFF(NS,NTR,NT,NCO,NSC,NCH,NP,ICF)
      NSC = 2
      CALL SCREENS(NS,NT,NCO,NSC)
      NCH = 1
      CALL CHEM(NS,NT,NCO,NSC,NCH)
      NP = NP+ 1
      CALL PAYOFF(NS,NTR,NT,NCO,NSC,NCH,NP,ICF)
      NCH = 2
      CALL CHEM(NS,NT,NCO,NSC,NCH)
      NP = NP + 1
```

```
      CALL PAYOFF(NS,NTR,NT,NCO,NSC,NCH,NP,ICF)
      IF(NCO.LT.MNC) GO TO 4
      IF(NT.LT.MNT) GO TO 3
      IF(NTR.LT.MNTR) GO TO 2
      NSE = NSE + 1
      IF(NSE.LT.NSEI) GO TO 1
      GO TO 1000
C
C     CALL ROUTINE FOR SINGLE PAYOFF CALCULATION
C
   20 CALL PLANT(NS,NTR,NT,IPF)
      CALL COOLING(NS,NT,NCO)
      CALL SCREENS(NS,NT,NCO,NSC)
      CALL CHEM(NS,NT,NCO,NSC,NCH)
      CALL PAYOFF(NS,NTR,NT,NCO,NSC,NCH,NP,ICF)
      NSE = NSE + 1
      IF(NSE.LT.NSEI) GO TO 1
 1000 STOP
      END
```

```
      SUBROUTINE TREE
C     SET UP OF FORMAT STATEMENTS FOR PRINTING OUT OF DECISION TREE
C     FOR THERMAL DISCHARGES BASELINE ANALYSIS PROGRAM
C     DECK MODIFICATIONS AS OF 22 MARCH 1972, 1115 HRS
C      DECK MOD NOS. ORIGINATED ON 19 MARCH AT 1600 RUN
C
C
C     FORMAT STATEMENTS FOR PRINTING THE DECISION TREE
C
    1 FORMAT(1H1,20X,*THERMAL DISCHARGE DECISION TREE ANALYSIS PROGRAM*/
     2,1H0,10X,* THE TREE BELOW SHOWS THE VARIOUS DECISION LEVELS AND TH
     3E ROUTINES  PROGRAMMED WITHIN EACH LEVEL*/*0 SITE/TRANSMISSION   P
     4OWER PLANT TYPE       COOLING METHOD       SCREENING OPTIONS  CHEM T
     5RT. OPTIONS    PAYOFF NO.*/)
    2 FORMAT(1H0,80X,30H *CHEM. DISCH NOT TR**PAYOFF 1)
    3 FORMAT(1H ,80X,1H*)
    4 FORMAT(1H ,60X,20H*NO INTAKE SCREENS**)
    5 FORMAT(1H ,59X,1H*,20X,1H*)
    6 FORMAT(1H ,58X,1H*,21X,30H *CHEM DISC TREATED***PAYOFF 2)
    7 FORMAT(1H ,57X,1H*)
    8 FORMAT(1H ,40X,17H* ONCE-THROUGH***)
    9 FORMAT(1H ,57X,1H*)
   10 FORMAT(1H ,39X,1H*,18X,1H*,21X,30H *CHEM DISCH NOT TRT**PAYOFF 3)
   11 FORMAT(1H ,59X,1H*,20X,1H*)
   12 FORMAT(1H ,38X,1H*,21X,20H*SCREENED INTAKES***)
   13 FORMAT(1H ,80X,1H*)
   14 FORMAT(1H ,37X,2H* ,41X,30H *CHEM DISC TREATED***PAYOFF 4,/)
   16 FORMAT(1H ,36X,1H*)
   17 FORMAT(1H ,            80X,30H *CHEM DISCH NOT TRT**PAYOFF 5)
   18 FORMAT(1H ,35X,1H*,44X,1H*)
   19 FORMAT(1H ,60X,        20H*NO INTAKE SCREENS**)
   20 FORMAT(1H ,34X,1H*,24X,1H*,20X,1H*)
   21 FORMAT(1H ,58X,1H*,21X,30H *CHEM DISC TREATED***PAYOFF 6)
   22 FORMAT(1H ,33X,1H*,23X,1H*)
   23 FORMAT(1H ,40X,17H* COOLING POND***)
   24 FORMAT(1H ,32X,1H*,24X,1H*)
   25 FORMAT(1H ,39X,1H*,     18X,1H*,22X,29H*CHEM DISCH NOT TRT**PAYOFF
     27)
   26 FORMAT(1H ,31X,1H*,27X,1H*,20X,1H*)
   27 FORMAT(1H ,38X,1H*,21X,20H*SCREENED INTAKES** )
   28 FORMAT(1H ,30X,1H*,49X,1H*)
   29 FORMAT(1H ,37X,1H*,     42X,30H *CHEM DISC TREATED***PAYOFF 8)
   30 FORMAT(1H ,29X,1H*)
   31 FORMAT(1H ,20X,17H* H2O NUC PWR PLT)
   32 FORMAT(1H ,29X,1H*)
   33 FORMAT(1H ,19X,1H*,17X,1H*,43X,29H*CHEM DICSH NOT TRT**PAYOFF 9)
   34 FORMAT(1H ,30X,1H*,49X,1H*)
   35 FORMAT(1H ,18X,1H*,19X,1H*,21X,20H*NO INTAKE SCREENS**)
   36 FORMAT(1H ,31X,1H*,48X,1H*)
   37 FORMAT(1H ,17X,1H*,21X,1H*,19X,1H*,21X,30H*CHEM DISC TREATED***PAY
     2OFF 10,/,1H ,32X,1H*)
   38 FORMAT(1H ,16X,1H*,23X,19H*MEC DFT WET TOWER*,/,1H ,33X,1H*)
   39 FORMAT(1H ,15X,1H*,43X,1H*,21X,30H*CHEM DISCH NOT TRT**PAYOFF 11)
   40 FORMAT(1H ,34X,1H*,45X,1H*)
   41 FORMAT(1H ,14X,1H*,45X,20H*SCREENED INTAKES***)
```

```
42 FORMAT(1H ,35X,1H*,44X,1H*)
43 FORMAT(1H ,13X,1H*,66X,31H *CHEM DISC TREATED***PAYOFF 12)
44 FORMAT(1H ,36X,1H*,/,1H ,12X,1H*)
45 FORMAT(1H ,          37X,1H*,43X,30H*CHEM DISCH NOT TRT**PAYOFF 13)
46 FORMAT(1H ,11X,1H*,68X,1H*)
47 FORMAT(1H ,          38X,1H*,21X,20H*NO INTAKE SCREENS**)
48 FORMAT(1H ,10X,1H*,69X,1H*)
49 FORMAT(1H ,          39X,1H*,19X,1H*,21X,30H*CHEM DISCH TREATED**PAY
  2OFF 14,/,10X,1H*)
50 FORMAT(1H ,40X,20H*NAT DFT WET TOWER* ,/,1H ,8X,1H*)
51 FORMAT(1H ,         59X,1H*,21X,30H*CHEM DISCH NOT TRT**PAYOFF 15)
52 FORMAT(1H ,7X,1H*,72X,1H*)
53 FORMAT(1H ,         60X,20H*SCREENED INTAKES***)
54 FORMAT(1H ,6X,1H*,73X,1H*)
55 FORMAT(1H ,         81X,30H*CHEM DISCH TREATED**PAYOFF 16)
56 FORMAT(1H ,5X,1H*)
57 FORMAT(21H0 SITE(NS)/TRANS(NTR))
58 FORMAT(1H ,4X,1H*)
59 FORMAT(1H ,         81X,30H*CHEM DISCH NOT TRT**PAYOFF 17)
60 FORMAT(1H ,5X,1H*,74X,1H*)
61 FORMAT(1H ,         60X,20H*NO INTAKE SCREENS**)
62 FORMAT(1H ,6X,1H*,52X,1H*,20X,1H*)
63 FORMAT(1H ,         58X,1H*,22X,30H*CHEM DISCH TREATED**PAYOFF 18)
64 FORMAT(1H ,7X,1H*,49X,1H*)
65 FORMAT(1H ,          40X,17H* ONCE-THROUGH***)
66 FORMAT(1H ,8X,1H*,48X,1H*)
67 FORMAT(1H ,          39X,1H*,18X,1H*,22X,30H*CHEM DISCH NOT TRT**PAY
  2OFF 19)
68 FORMAT(1H ,9X,1H*,49X,1H*,20X,1H*)
69 FORMAT(1H ,          38X,1H*,21X,20H*SCREENED INTAKES***)
70 FORMAT(1H ,10X,1H*,69X,1H*)
71 FORMAT(1H ,          37X,1H*,43X,30H*CHEM DISC TREATED***PAYOFF 20)
72 FORMAT(1H ,11X,1H*,/,1H ,36X,1H*)
73 FORMAT(1H ,12X,1H*,68X,30H*CHEM DISCH NOT TRT**PAYOFF 21)
74 FORMAT (1H ,35X,1H*,44X,1H*)
75 FORMAT(1H ,13X,1H*,46X,20H*NO INTAKE SCREENS**)
76 FORMAT(1H ,34X,1H*,24X,1H*,20X,1H*)
77 FORMAT(1H ,14X,1H*,43X,1H*,22X,30H*CHEM DISC TREATED***PAYOFF 22)
78 FORMAT(1H ,33X,1H*,23X,1H*)
79 FORMAT(1H ,15X,1H*,24X,17H* COOLING POND***)
80 FORMAT(1H ,32X,1H*,24X,1H*)
81 FORMAT(1H ,16X,1H*,22X,1H*,18X,1H*,22X,30H*CHEM DISCH NOT TRT**PAY
  2OFF 23)
82 FORMAT(1H ,31X,1H*,27X,1H*,20X,1H*)
83 FORMAT(1H ,17X,1H*,20X,1H*,21X,20H*SCREENED INTAKES***)
84 FORMAT(1H ,30X,1H*,49X,1H*)
85 FORMAT(1H ,18X,1H*,18X,1H*,43X,30H*CHEM DISC TREATED***PAYOFF 24)
86 FORMAT(1H ,29X,1H*)
87 FORMAT(1H ,19X,18H* FOSSIL FIRED PLT)
88 FORMAT(1H ,29X,1H*)
89 FORMAT(1H ,37X,1H*,43X,30H*CHEM DISCH NOT TRT**PAYOFF 25)
90 FORMAT (1H ,30X,1H*,49X,1H*)
91 FORMAT(1H ,38X,1H*,21X,20H*NO INTAKE SCREENS**)
92 FORMAT(1H ,31X,1H*,48X,1H*)
93 FORMAT(1H ,39X,1H*,19X,1H*,21X,30H*CHEM DISC TREATED***PAYOFF 26)
94 FORMAT(1H ,32X,1H*)
```

```
 95 FORMAT(1H ,40X,19H*MEC DFT WET TOWER*,/,1H ,33X,1H*)
 96 FORMAT(1H ,59X,1H*,21X,30H*CHEM DISCH NOT TRT**PAYOFF 27)
 97 FORMAT(1H ,34X,1H*,45X,1H*)
 98 FORMAT(1H ,60X,20H*SCREENED INTAKES***,/,1H ,35X,1H*,44X,1H*)
 99 FORMAT(1H ,81X,30H*CHEM DISC TREATED***PAYOFF 28)
100 FORMAT(1H ,36X,1H*,/,1H )
101 FORMAT(1H ,37X,1H*,43X,30H*CHEM DISCH NOT TRT**PAYOFF 29)
102 FORMAT(1H ,80X,1H*,/,1H ,38X,1H*,21X,20H*NO INTAKE SCREENS**)
103 FORMAT(1H ,80X,1H*)
104 FORMAT(1H ,39X,1H*,19X,1H*,21X,30H*CHEM DISCH TREATED**PAYOFF 30,/
   2,1H )
105 FORMAT(1H ,40X,19H*NAT DFT WET TOWER*)
106 FORMAT(1H0,59X,1H*,21X,30H*CHEM DISCH NOT TRT**PAYOFF 31)
107 FORMAT(1H ,80X,1H*,/,1H ,60X,20H*SCREENED INTAKES***)
108 FORMAT(1H ,80X,1H*,/,1H ,81X,30H*CHEM DISCH TREATED**PAYOFF 32)
    PRINT 1 $ PRINT 2 $ PRINT 3 $ PRINT 4 $ PRINT 5 $ PRINT 6
    PRINT 7 $ PRINT 8 $ PRINT 9 $ PRINT 10 $ PRINT 11 $ PRINT 12
    PRINT 13 $ PRINT 14 $           PRINT 16 $ PRINT 17 $ PRINT 18
    PRINT 19 $ PRINT 20 $ PRINT 21 $ PRINT 22 $ PRINT 23 $ PRINT 24
    PRINT 25 $ PRINT 26 $ PRINT 27 $ PRINT 28 $ PRINT 29 $ PRINT 30
    PRINT 31 $ PRINT 32 $ PRINT 33 $ PRINT 34 $ PRINT 35 $ PRINT 36
    PRINT 37 $ PRINT 38 $ PRINT 39 $ PRINT 40 $ PRINT 41 $ PRINT 42
    PRINT 43 $ PRINT 44 $ PRINT 45 $ PRINT 46 $ PRINT 47 $ PRINT 48
    PRINT 49 $ PRINT 50 $ PRINT 51 $ PRINT 52 $ PRINT 53 $ PRINT 54
    PRINT 55 $ PRINT 56 $ PRINT 57 $ PRINT 58 $ PRINT 59 $ PRINT 60
    PRINT 61 $ PRINT 62 $ PRINT 63 $ PRINT 64 $ PRINT 65 $ PRINT 66
    PRINT 67 $ PRINT 68 $ PRINT 69 $ PRINT 70 $ PRINT 71 $ PRINT 72
    PRINT 73 $ PRINT 74 $ PRINT 75 $ PRINT 76 $ PRINT 77 $ PRINT 78
    PRINT 79 $ PRINT 80 $ PRINT 81 $ PRINT 82 $ PRINT 83 $ PRINT 84
    PRINT 85 $ PRINT 86 $ PRINT 87 $ PRINT 88 $ PRINT 89 $ PRINT 90
    PRINT 91 $ PRINT 92 $ PRINT 93 $ PRINT 94 $ PRINT 95 $ PRINT 96
    PRINT 97 $ PRINT 98 $ PRINT 99 $ PRINT 100 $ PRINT 101 $ PRINT 102
    PRINT 103 $ PRINT 104 $ PRINT 105 $ PRINT 106 $ PRINT 107
    PRINT 108
    RETURN
    END
```

```
      SUBROUTINE COOLING(NS, NT,NCO)
C     COOLING IS A DUMMY SUBPROGRAM USED TO CALL THE APPLICABLE
C      DYNATECH SUBPROGRAM FOR COOLING ANALYSIS
      IF(NCO.EQ.1) CALL ONCE(NS,NT,NCO)
      IF(NCO.EQ.2) CALL POND(NS,NT,NCO)
      IF(NCO.EQ.3) CALL MCHDFT(NS,NT,NCO)
      IF(NCO.EQ.4) CALL NATDFT(NS,NT,NCO)
      RETURN
      END
```

```
      SUBROUTINE POND(NS,NT,NCO)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      PMPEF=0.8 $ TOTCS1=1.E3 $ WCOFA=0. $ WCOFB=15. $ TA=TDB $ TG=TDB
C           CALC OF EQULIBRIUM TEMPERATURE
      ECOF=WCOFA+WCOFB*WIND
      TA=TDB
      TG=TDB
    7 DH=RAD-1801.*(TG/460.+1.)**4-ECOF*51.7*(P(TG)-RH*P(TA)) -.26*ECO
     XF*(TG-TA)
      DHP=RAD-1801.*((TG+1.)/460.+1.)**4-ECOF*51.7*(P(TG+1.)-RH*P(TA)) -
     X.26*ECOF*(TG+1.-TA)
      DHM=RAD-1801.*((TG-1.)/460.+1.)**4-ECOF*51.7*(P(TG-1.)-RH*P(TA)) -
     X.26*ECOF*(TG-1.-TA)
      DHPRIM=(DHP-DHM)/2.
      IF(ABS(DH)-1.)1,2,2
    2 TNEW=TG-DH/DHPRIM
      TG=TNEW
      GO TO 7
    1 TCALC=TG
      BETA=51.7*(P(TCALC+1.)-P(TCALC-1.))/2.
      XK=15.7+(0.26+BETA)*ECOF
      TC=TCMIN(NCAPS+1)
  100 CONTINUE
      IF(NSPCON-1)30,40,30
   40 CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
      DT2=(QREJ/SPFLOW)/(EXP(UOVALL*AREAC/SPFLCW)-1.)
      DT1=DT2+QREJ/SPFLOW
      T1=TC-DT2
      IF(NSYSOP-2)44,41,44
   41 IF(TDISMX.LT.TCALC)GO TO 197
      IF(DT1-(TC-TAVH2O))15,15,42
   42 IF(TC-TCMAX(NCAPS+1))13,190,190
   13 TC=TC+1
      GO TO 40
   15 T2=TDISMX
      RA=T1-T2
      IF(RA.LT.0.)GO TO 190
      GO TO 46
   44 T2=TC-DT1
      IF(T2-TCALC)151,151,45
   30 DT2=5.
      IF(NSYSOP-2)31,32,31
   31  T2=TCALC+1.
      GO TO 50
   32 IF(TDISMX.LT.TCALC)GO TO 197
      T2=TDISMX
```

```
   50  IF((TC-DT2)-T2)151,151,51
   51  CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
       IF(NSYSOP-2)45,46,45
   45  CALL COND(TC,T2,QREJ,PWCST,DT2,T1,UA,FLOW,GPM,SYSCST,COSPKW)
       QREJT=QREJ
       GO TO 47
   46  CALL COND(TC,TAVH2O,QREJ,PWCST,DT2,T1,UA,FLOW,GPM,SYSCST,COSPKW)
       QREJT=QREJ*(T1-T2)/(T1-TAVH2O)
   47  RA=T1-T2
       ALPHA=-ALOG((T2-TCALC)/(T1-TCALC))
       AREAP=24.*ALPHA*FLOW/(XK*43560.)
C          ALOG MEAN T DIF BETWEEN AIR AND WATER
       IF(T2-TDB)48,48,49
   48  WLMTD=(T1+T2)/2.-TDB
       GO TO 53
   49   WLMTD=(T1-T2)/ALOG((T1-TDB)/(T2-TDB))
C          BOWEN RATIO - RATIO OF CONDUCTION TO EVAPORATION
C        HEAT TRANSFER - MODIFIED FROM EDINGER AND GEYER
   53   TWAV=(T1+T2)/2.
       BOWRAT=.26*WLMTD/(51.7*(P(TWAV)-RH*P(TDB)))
       QLAT=(QREJT-(.173E-8*((T1+T2)/2.+460.)**4-RAD/24.)*AREAP*
      *  43560.)/(1.+BOWRAT)
       WEVAP=QLAT/970.3
       GPMT=GPM+WEVAP/(8.34*60.)
C          ASSUME 30 FT OF PUMPING HEAD (FRICTION)
C      PHEAD=30.
C      CHANGE PHEAD TO UNITY(1) AS DONE BY EPA--CORVALLIS
       PHEAD = 1.0
       HPPMP=GPMT*PHEAD/(3960.*PMPEF)
       CAPCOS=AREAP*PRPAGR
       DELFC=DELFC*USEFAC
       OPCOS=(HPPMP*.7457/(PSIZE*1000.))*PWCST*USEFAC
       COSMAI=.001*CAPCOS/(PSIZE*1000.)+.1*OPCOS+.01*SYSCST
       TOTCOS=(CAPCOS*ANFCR)/(PSIZE*1000.*CAPFAC*8.76) +OPCOS +COSMAI+SYS
      XCST+DELFC
       IF(TOTCOS-TOTCS1)154,156,156
  156  IF(NSPCON.EQ.1)GO TO 157
       IF(NSYSOP.EQ.2)GO TO 151
       T2=T2+1.
       GO TO 50
  157  IF(NSYSOP.EQ.2)GO TO 190
  151  TC=TC+1.
       IF(TC-TCMAX(NCAPS+1))100,100,190
  154  RA1=RA
       AREAP1=AREAP $ T11=T1 $ T21=T2 $ SYS1=SYSCST $ CAPCS1=CAPCOS
       COSPK1=COSPKW $ OPCS1=OPCOS $ COSMA1=COSMAI $ AFLR1=0. $ HPF1=0.
       HPP1=HPPMP $ DELF1=DELFC $ TCALC1=TCALC $ QRJ1=QREJ $QRJT1=QREJT
       FLOW1=FLOW $ GPM1=GPM $ UA1=UA $ WEVAP1=WEVAP
       WBDWN1 = 0.0 $ WATER(NCO)=WEVAP/224700. $ DISCH(NCO)=0.0
       TDIS(NCO)=0.0 $ CDIS(NCO) =0.0 $ CSC = TOTCS1 $ SPCO = AREAP
       TC1=TC $ TOTCS1=TOTCOS $ CCSC = CAPCS1 $ GO TO 156
  190  IF(TOTCS1-1.E3)200,195,200
  195  WRITE(IRITE,196)TC,T1,RA
  196  FORMAT(/3X,*FOR THE GIVEN CONDITIONS A SOLUTION CANNOT BE FOUN
      XD*,/,3X,*TC =*,F5.0,*    T1 =*,F5.0,*     RA =*,F5.0)
       GO TO 400
```

```
197  WRITE(IRITE,198)
198  FORMAT(/,3X,*MAX DIS T LESS THAN EQULIBRIUM T*)
     GO TO 400
200  CONTINUE
     IF(IOO.EQ.1) GO TO 500
      WRITE(IRITE,212)
212  FORMAT(*1*,15X,*----- COOLING POND -----*,//, 10X,  *THE DESIGN V
    XALUES AND COSTS ARE -*,//)
      CALL PRTOS1(QRJ1,TC1,HPF1,HPP1,WEVAP1,WBOWN1,AFLR1)
     WRITE(IRITE,227)FLOW1,T11,RA1,TCALC1,AREAP1
227 FORMAT(3X,*COND FLOW =*,E12.4,*     T IN =*,F4.0,*      RANGE =*
    X,F4.0,/,3X,*EQULIBRIUM TEMP =*,F4.0,* DEG F.  POND AREA =*,F8.0,
    X* ACRES*)
     IF(NSYSOP-2)230,228,230
228  WRITE(IRITE,229)QRJT1
229  FORMAT(/3X,*Q REJ POND =*,E12.4,* BTU/HR*)
230  CALL PRTOS2(CAPCS1,OPCS1,COSMA1,SYS1,DELF1,TOTCS1,COSPK1)
     WRITE(IRITE,330)
330  FORMAT(//15X,*VARIABLE AMBIENT CONDITIONS*/)
500 IF(NTAMB.EQ.0)GO TO 400
     TOPMIL=0.0 $ TDFMIL=0.0
     DO 350 I=1,NCAPS
     IF(CAP(I).EQ.0.)GO TO 350
     AMBOPC(I)=0.0 $ AMBDFC(I)=0.0
     DO 340 J=1,NTAMB
     IF(PCTAMB(I,J).EQ.0.)GO TO 340
     TC=TCMIN(I) $ NTCOD=0. $ TA=TAMDB(J) $ TG=TA $ RAD=AMRAD(J)
     ECOF=WCOFA+WCOFB*AMWIND(J)
 20  DH=RAD-1801.*(TG/460.+1.)**4-ECOF*51.7*(P(TG)-AMBRH(J)* P(TA))-
    X.26*ECOF*(TG-TA)
     DHP=RAD-1801.*((TG+1.)/460.+1.)**4-ECOF*51.7*(P(TG+1.)-AMBRH(J)*
    XP(TA))-.26*ECOF*(TG+1.-TA)
     DHM=RAD-1801.*((TG-1.)/460.+1.)**4-ECOF*51.7*(P(TG-1.)-AMBRH(J)*
    XP(TA))-.26*ECOF*(TG-1.-TA)
     DHPRIM=(DHP-DHM)/2.
     IF(ABS(DH)-1.)21,22,22
 22  TNEW=TG-DH/DHPRIM
     TG=TNEW
     GO TO 20
 21  TCALC=TG
     BETA=51.7*(P(TCALC+1.)-P(TCALC-1.))/2.
     XK=15.7+(.26+BETA)*ECOF
     ALPACT=(AREAP1*XK*43560.)/(24.*FLOW1)
301  CALL PAFCST(I,TC,PWCST,DFCOD,QREJ)
     DT2=(QREJ/FLOW1)/(EXP(UA1/FLOW1)-1.)
     DT1=DT2+QREJ/FLOW1
     T1=TC-DT2
     T2=TC-DT1
     IF(NSYSOP-2)316,303,316
316  IF(T2-TCALC)304,304,302
303  IF(T2-TAMRV(J))304,305,306
305  NTCOD=1
     GO TO 306
306  T2=TCALC+(T1-TCALC)/EXP(ALPACT)
     IF(T2-TDISMX)310,310,307
307  WRITE(IRITE,308)CAP(I),TAMWB(J),TC,T2
```

```
308  FORMAT(/8X*FOR CAP =*,F4.2,*,     T WB =*,F4.0,*, AND   TC =*
   X,F4.0,/,3X*T DIS EXCEEDS TDIS MAX - CONTINUING*)
    GO TO 315
302  ALPHA=-ALOG((T2-TCALC)/(T1-TCALC))
    IF(ALPHA.LT.ALPACT)GO TO 310
304  TC=TC+1.
    NTCOD=1
    IF(TC .LT. TCMAX(I))GO TO 301
    IF(IOO.GT.1) PRINT 309, CAP(I), J
309 FORMAT(*-      THE POND IS ESSENTIALLY TOO SMALL FOR*,F4.2,
   2  * CAPACITY AND AMBIENT NO.*,I2/* PROGRAM DISCONTINUING*)
    GO TO 400
310  IF(NTCOD.GT.0)GO TO 315
       IF(IOO.GT.1) PRINT 312, CAP(I), J
312 FORMAT(*0THE POND IS LARGER THAN NECESSARY FOR*,F4.2,* CAPACITY*,
   *  * AND AMBIENT NO.*,I2/
   ** COMPUTING COSTS ASSUMING MOST EFFICIENT CONDITION (PC=PCMIN)*)
    IF(DFCOD.GT.0.)DFCOD=0.0
315  CONTINUE
    OPCOD=(HPP1*.7457/(PSIZE*1000.))*PWCST
    AMBOPC(I)=AMBOPC(I)+OPCOD*PCTAMB(J)
    AMBDFC(I)=AMBDFC(I)+DFCOD*PCTAMB(J)
340  CONTINUE
    TOPMIL=TOPMIL+AMBOPC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
    TDFMIL=TDFMIL+AMBDFC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
350  CONTINUE
    AVOPCS=TOPMIL/TKWHRS
    AVDFCS=TDFMIL/TKWHRS
    AVTCST=(CAPCST*ANFCR)/(PSIZE*1000.*CAPFAC*8.76) +AVOPCS+AVDFCS+SYS
   X1+COSMA1
    IF(IOO.GT.1) CALL PRTOD(AVOPCS,AVDFCS,AVTCST)
400  CONTINUE
    RETURN
    END
```

```
      SUBROUTINE MCHDFT(NS,NT,NCO)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMCS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,IZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      DIMENSION XK(20)
      FANEF=0.8 $ PMPEF=0.8 $ TOTCS1=1.E3 $ TC=TCMIN(NCAPS+1)
100   CONTINUE
      IF(NSPCON-1)30,40,30
 40   CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
      DT2=(QREJ/SPFLOW)/(EXP(UOVALL*AREAC/SPFLOW)-1.)
      DT1=DT2+QREJ/SPFLOW
      T1=TC-DT2
      IF(NSYSOP-2)44,41,44
 41   IF(DT1-(TC-TAVH2O))15,15,42
 42   IF(TC-TCMAX(NCAPS+1))13,190,190
 13   TC=TC+1
      GO TO 40
 15   T2=TDISMX
      APPR=T2-TWB
      IF(APPR.LT.7.)GO TO 190
      IF(APPR.GT.20.)GO TO 190
      RA=T1-T2
      IF(RA.LT.10.)GO TO 190
      GO TO 46
 44   T2=TC-DT1
      APPR=T2-TWB
      IF(APPR.LT.7.)GO TO 151
      IF(APPR.GT.20.)GO TO 190
      GO TO 45
 30   IF(NSYSOP-2)31,32,31
 31   APPR=7.
 50   T2=TWB+APPR
      IF(TC-T2)151,151,51
 32   T2=TDISMX
      APPR=T2-TWB
      IF(APPR.LT.7.)GO TO 190
      IF(APPR.GT.20.)GO TO 190
 51   DT2=5.
      CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
      IF(NSYSOP-2)45,46,45
 45   CALL COND(TC,T2,QREJ,PWCST,DT2,T1,UA,FLOW,GPM,SYSCST,
     *  COSPKW)
      QREJT=QREJ
      GO TO 47
 46   CALL COND(TC,TAVH2O,QREJ,PWCST,DT2,T1,UA,FLOW,GPM,SYSCST,
     *  COSPKW)
      QREJT=QREJ*(T1-T2)/(T1-TAVH2O)
 47   RA=T1-T2
```

```
      IF(RA.LT.10.)GO TO 151
      TAXT=(T1+T2)/2.
      H1=H(TWB)
      H2=H(TAXT)
      AFLR=QREJT/(H2-H1)
      WACT=RH*(.622*P(TDB))/(14.696-P(TDB))
      APSAT=(WACT*14.696)/(.622+WACT)
      DIN=144.*(14.696-APSAT)/(53.35*(TDB+460.))
      WART=FLOW/AFLR
      T3=T2+.1*RA
      T4=T2+.4*RA
      T5=T1-.4*RA
      T6=T1-.1*RA
      CO1=WART*RA
      RDH1=1./(H(T3)-H1-.1*CO1)
      RDH2=1./(H(T4)-H1-.4*CO1)
      RDH3=1./(H(T5)-H2+.4*CO1)
      RDH4=1./(H(T6)-H2+.1*CO1)
      CHAR=(RA/4.)*(RDH1+RDH2+RDH3+RDH4)
C
C          PACKING HEIGHT FROM FRAAS + OZISIK - DECK NUMBER J
      DECKHT =2.
      PHT=DECKHT*(CHAR-.07)/(.103*WART**(-.54))
C           WATER LOADING = 2500
      WLOAD=2500.
      PLANA=FLOW/WLOAD
C           AIR LOADING OR G
      ALDG=AFLR/PLANA
      ALDGE=ALDG+3500.
C
C          PRESSURE DROP (INCHES OF WATER) FROM FRAAS AND OZISIK
      DELP=((PHT/DECKHT)*.0675/DIN)*(0.4E-8*ALDG**2 +.1E-12*2500.*ALDGE*
     X*2*2.62)
      RANGE=RA
      IK=APPR
      IF(GPM) 210,210,11
C          CALK OF K FACTOR - LOCKHART ET AL
   11  IF(IK-7)370,7,1
    1  IF(IK-20)2,2,370
    2  IF(IK-10)6,5,5
    6 IAXY=IK-7
        GO TO (8,9)IAXY
    7   XK(7)=.42626139+.30755494*RANGE-.83222851E-02*RANGE**2+.14
     X130379E-03*RANGE**3-.87533682E-06*RANGE**4
      GO TO 25
    8   XK(8)=.53003286+.26855945*RANGE-.71968070E-02*RANGE**2+.12
     X092005E-03*RANGE**3-.73568322E-06*RANGE**4
      GO TO 25
    9   XK(9)=.27667081+.27125055*RANGE-.75042365E-02*RANGE**2+.12
     X884963E-03*RANGE**3-.80021960E-06*RANGE**4
      GO TO 25
    5   AA=APPR/2.
      Z=0.
      IA=AA
      AB=IA
      IXYZ=IA-4
```

```
      IF(AB.EQ.AA)GO TO (10,12,14,16,18,20)IXYZ
      GO TO (10,12,14,16,18)IXYZ
 21    Z=2.
      GO TO (12,14,16,18,20)IXYZ
 10    XK(10)=.87557520E-01+.25976379*RANGE-.69589515E-02*RANGE**2
     X  +.11542869E-03*RANGE**3-.69832755E-06*RANGE**4
      IF(AB.EQ.AA)GO TO 25
      IF(Z-2.)21,23,21
 12    XK(12)=.30755983E-02+.22692621*RANGE-.57515664E-02*RANGE**2
     X  +.89248959E-04*RANGE**3-.50381046E-06*RANGE**4
      IF(AB.EQ.AA)GO TO 25
      IF(Z-2.)21,23,21
 14    XK(14)=-.33616133+.22612638*RANGE-.57931043E-02*RANGE**2
     X+.89896029E-04*RANGE**3-.50893025E-06*RANGE**4
      IF(AB.EQ.AA)GO TO 25
      IF(Z-2.)21,23,21
 16    XK(16)=-.43379805+.20785695*RANGE-.51672632E-02*RANGE**2
     X+.77053656E-04*RANGE**3-.42119093E-06*RANGE**4
      IF(AB.EQ.AA)GO TO 25
      IF(Z-2.)21,23,21
 18    XK(18)=-.91434163+.23827008*RANGE-.66801246E-02*RANGE**2
     X+.10604073E-03*RANGE**3-.61338627E-06*RANGE**4
      IF(AB.EQ.AA)GO TO 25
      IF(Z-2.)21,23,21
 20    XK(20)=-.12250402E+01+.25793956*RANGE-.7655059E-02*RANGE**2
     X  +.12169709E-03*RANGE**3-.70610963E-06*RANGE**4
      IF(AB.EQ.AA)GO TO 25
      IF(Z-2.)21,23,21
 23    XK(IK)=(XK(IK-1)+XK(IK+1))/2.
 25   CONTINUE
      CWB=.7+EXP(4.17-.0767*TWB)
      DELHS=QREJT/AFLR
      HOUT=H1+DELHS
      TOUTS=.99674408E1+.24105952E1*HOUT-.22686654E-1*HOUT**2  + .102553
     X04E-3*HOUT**3-.14174090E-6*HOUT**4
      QLAT=QREJT-AFLR*.24*(TOUTS-TDB)
      WEVAP=QLAT/970.3
      CONCR=5.
C           WATER FOR BLOWDOWN
      WBDWN=(.06*QREJT*62.4)/(500.*7.48*(CONCR-1.))
      WNDG = 0.002*FLOW
      WNEED = WEVAP + WBDWN +WNDG
      GPMT=GPM+WNEED/(8.34*60.)
      FUDGE=GPMT*XK(IK)*CWB
C           LOCKHART SAYS COST = 2*FUDGE BUT CONVERSES COSTS ARE
C           ABOUT 2*LOCKHARTS - USE AVG. = 3*FUDGE
      CAPCOS=3.*FUDGE
      ACFM=AFLR/(60.*DIN)
      HPFAN=(ACFM*DELP*5.2)/(33000.*FANEF)
      HPPMP=GPMT*(PHI+10.)/(3960.*PMPEF)
      TOTHP=HPFAN+HPPMP
      DELFC=DELFC*USEFAC
      OPCOS=(TOTHP*.7457/(PSIZE*1000.))*PWCST*USEFAC
      COSMAI=.001*CAPCOS/(PSIZE*1000.)+.1*OPCOS+.01*SYSCST
      TOTCOS=(CAPCOS*ANFCR)/(PSIZE*1000.*CAPFAC*8.76) +OPCOS
     X +COSMAI+SYSCST+DELFC
```

```
      IF(TOTCOS-TOTCS1)154,156,156
156   IF(NSPCON.EQ.1)GO TO 157
      IF(NSYSOP.EQ.2)GO TO 151
      APPR=APPR+1.
      IF(APPR-20.)50,50,151
157   IF(NSYSOP.EQ.2)GO TO 190
151   TC=TC+1.
      IF(TC-TCMAX(NCAPS+1))100,100,190
154   RA1=RA
      CHAR1=CHAR $ PHT1=PHT $ PLANA1=PLANA $ AFLR1=AFLR $ DP1=DELP
      APPR1=APPR $ HWB1=H1 $ SYS1=SYSCST $ CAPCS1=CAPCOS $ COSPK1=COSPKW
      OPCS1=OPCOS $ COSMA1=COSMAI $ THP1=TOTHP $ HPF1=HPFAN $ HPP1=HPPMP
      DELF1=DELFC $ QRJ1=QREJ $ QRJT1=QREJT $ FLOW1=FLOW $ GPM1=GPM
      WART1=WART $ UA1=UA $ WEVAP1=WEVAP $ WBOWN1=WBOWN $ WNEED1=WNEED
      TC1=TC $ XK1=XK(IK) $ TOTCS1=TOTCOS
      WATER(NCO)=WNEED1/224700. $ DISCH(NCO)=WBOWN1/224700.
      TDIS(NCO)=TOUTS $CDIS(NCO)=CONCR $ CSC = TOTCS1 $ SPCO = 20.
      CCSC = CAPCS1
      GO TO 156
190   IF(TOTCS1-1.E3)200,195,200
195   WRITE(IRITE,196)TC,APPR,RA
196   FORMAT(/3X,*FOR THE GIVEN CONDITIONS A SOLUTION CANNOT BE
     X FOUND*,/,3X,*TC =*,F5.0,*     APPR =*,F5.0,*     RA =*,F5.0)
      GO TO 400
200   CONTINUE
      IF(IOO.EQ.1) GO TO 500
210   WRITE(IRITE,212)
212   FORMAT(*1*,15X,*----- MECHANICAL DRAFT WET TOWER -----*,//, 10
     XX,*THE DESIGN VALUES AND COSTS ARE -*,//)
      CALL PRTDS1(QRJ1,TC1,HPF1,HPP1,WEVAP1,WBOWN1,AFLR1)
      WRITE(IRITE,227)DP1,FLOW1,RA1,APPR1
227   FORMAT(3X,*PRESSURE DROP =*,F5.2,*     COND FLOW =*,E12.4,/,
     X 3X*RANGE =*,F4.0,*      APPROACH =*,F4.0)
      IF(NSYSOP-2)230,228,230
228   WRITE(IRITE,229)QRJT1
229   FORMAT(/3X,*Q REJ TOWER =*,E9.2,* BTU/HR*)
230   CALL PRTDS2(CAPCS1,OPCS1,COSMA1,SYS1,DELF1,TOTCS1,COSPK1)
      WRITE(IRITE,330)
330   FORMAT(//15X,*VARIABLE AMBIENT CONDITIONS*/)
500   IF(NTAMB.EQ.0)GO TO 400
      TOPMIL=0.0
      TDFMIL=0.0
      DO 350 I=1,NCAPS
      IF(CAP(I).EQ.0.)GO TO 350
      AMBOPC(I)=0.0
      AMBDFC(I)=0.0
      DO 340 J=1,NTAMB
      IF(PCTAMB(I,J).EQ.0.)GO TO 340
      TC=TCMIN(I)
      NTCOD=0
301   CALL PAFCST(I,TC,PWCST,DFCOD,QREJ)
      DT2=(QREJ/FLOW1)/(EXP(UA1/FLOW1)-1.)
      DT1=DT2+QREJ/FLOW1
      T1=TC-DT2
      T2=TC-DT1
      IF(NSYSOP-2)316,303,316
```

```
316  IF(T2-TAMWB(J))304,304,302
303  IF(T2-TAMRV(J))304,305,306
305  NTCOU=1
306  T2=TDISMX
     IF(T2.GT.TAMWB(J))GO TO 302
     WRITE(IRITE,313)TAMWB(J)
313  FORMAT(3X*T DIS MAX LESS THAN(OR =) T WB =*,F4.0,/,
    X 3X*REQUIRES NEGATIVE APPROACH - DISCONTINUING*)
     GO TO 400
302  TAXT=(T1+T2)/2.
     RA=T1-T2
     T3=T2+.1*RA
     T4=T2+.4*RA
     T5=T1-.4*RA
     T6=T1-.1*RA
     CO1=WART1*RA
     H1=H(TAMWB(J))
     H2=H(TAXT)
     RDH1=1./(H(T3)-H1-.1*CO1)
     RDH2=1./(H(T4)-H1-.4*CO1)
     RDH3=1./(H(T5)-H2+.4*CO1)
     RDH4=1./(H(T6)-H2+.1*CO1)
     CHAR=(RA/4.)*(RDH1+RDH2+RDH3+RDH4)
     IF(CHAR .LT. CHAR1) GO TO 310
     IF(NSYSOP-2)304,307,304
307  IF(IOO.GT.1) PRINT 308, CAP(I), TAMWB(J), TC
308  FORMAT(/8X*FOR CAP =*,F4.2,*,     T WB =*,F4.0,           *, AND
    X   TC =*,F4.0,/,3X*T DIS EXCEEDS TDIS MAX - CONTINUING*)
     GO TO 315
304  TC=TC+1.
     NTCOU=1
     IF(TC .LT. TCMAX(I))GO TO 301
     WRITE(IRITE,309)PCMAX(I),CAP(I),TAMWB(J)
309  FORMAT(/,3X,*CONDENSER PRESS MUST EXCEED THE GIVEN MAX OF*,/ 8
    XX,F4.2,* FOR THE CAPACITY OF*,F4.2,* AT T WET BULB =*,F5.0,/,3X,*
    XPROGRAM DISCONTINUING*)
     GO TO 400
310  IF(NTCOU.GT.0)GO TO 315
     IF(IOO.GT.1) PRINT 312, CAP(I), TAMWB(J), TC
312  FORMAT(/8X,*FOR CAP =*,F4.2,*,    T WB =*,F5.0,*,  AND
    X  TC =*,F4.0,/,3X*PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE*)
     IF(DFCOD.GT.0.)DFCOD=0.0
315  CONTINUE
     OPCOD=(THP1*.7457/(PSIZE*1000.))*PWCST
     AMBOPC(I)=AMBOPC(I)+OPCOD*PCTAMB(J)
     AMBDFC(I)=AMBDFC(I)+DFCOD*PCTAMB(J)
340  CONTINUE
     TOPMIL=TOPMIL+AMBOPC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
     TDFMIL=TDFMIL+AMBDFC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
350  CONTINUE
     AVOPCS=TOPMIL/TKWHRS
     AVDFCS=TDFMIL/TKWHRS
     AVTCST=(CAPCS1*ANFCR)/(PSIZE*1000.*CAPFAC*8.76) +AVOPCS+AVDFCS+SYS
    X1+COSMA1
     IF(IOO.GT.1) CALL PRTOD(AVOPCS,AVDFCS,AVTCST)
     GO TO 400
```

```
370  WRITE(IRITE,371) APPR
371  FORMAT(* APPROACH=*,F7.1,* NO CURVES - RUN ABORTED*)
     GO TO 400
400  CONTINUE
     RETURN
     END
```

```
      SUBROUTINE NATDFT(NS,NT,NCO)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TCTLD(5), CCLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2C,TCEASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),   TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,   NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAC(5),WIND,RAD,GFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LCCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLCH1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH(10),TZERC,NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCC, DELHR, CCSC, CCOST, CCOSTS, SPNC,ICC
      PI=3.14159
      PMPEF=0.8
      TOTCS1=1.E3
      HORMAX=1.5
      TC=TCMIN(NCAPS+1)
  100 CONTINUE
      IF(NSPCON-1)30,40,30
   40 CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
      DT2=(QREJ/SPFLOW)/(EXP(UOVALL*AREAC/SPFLOW)-1.)
      DT1=DT2+QREJ/SPFLOW
      T1=TC-DT2
      IF(NSYSOP-2)44,41,44
   41 IF(DT1-(TC-TAVH2O))15,15,42
   42 IF(TC-TCMAX(NCAPS+1))13,190,190
   13 TC=TC+1
      GO TO 40
   15 T2=TDISMX
      APPR=T2-TWB
      IF(APPR.LT.12.) GO TO 190
      IF(APPR.GT.20.)GO TO 190
      RA=T1-T2
      IF(RA.LT.10.)GO TO 190
      GO TO 46
   44 T2=TC-DT1
      APPR=T2-TWB
      IF(APPR.LT.12.) GO TO 190
      IF(APPR.GT.20.)GO TO 190
      GO TO 45
   30 IF(NSYSOP-2)31,32,31
   31 APPR=12.
   50 T2=TWB+APPR
      IF(TC-T2)151,151,51
   32 T2=TDISMX
      APPR=T2-TWB
      IF(APPR.LT.12.) GO TO 190
      IF(APPR.GT.20.)GO TO 190
   51 DT2=5.
      CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
      IF(NSYSOP-2)45,46,45
   45 CALL COND(TC,T2,QREJ,PWCST,DT2,T1,UA,FLCW,GPM,SYSCST,
     * COSPKW)
      QREJT=QREJ
      GO TO 47
   46 CALL COND(TC,TAVH2C,QREJ,PWCST,DT2,T1,UA,FLCW,GPM,SYSCST,
```

```
     *  COSPKW)
      QREJT=QREJ*(T1-T2)/(T1-TAVH2O)
   47  RA=T1-T2
      IF(RA.LT.10.)GO TO 151
      WLOAD=1250.
C          INITIAL WATER LOADING  1250 LBM/FT2/HR
      BSA=FLOW/WLOAD
      DIA=SQRT(4.*BSA/3.14159)
C          TAXT - AIR EXIT TEMP - FRAAS + OZISIK
      TAXT=(T1+T2)/2.
      H1=H(TWB)
      H2=H(TAXT)
      AFLR=QREJ/(H2-H1)
      WART=FLOW/AFLR
C          CALC OF CHAR(TOTAL REQUIRED TOWER CHARACTERISTIC) FROM CTI
      T3=T2+0.1*RA
      T4=T2+0.4*RA
      T5=T1-0.4*RA
      T6=T1-0.1*RA
      CO1=WART*RA
      RDH1=1./(H(T3)-H1-0.1*CO1)
      RDH2=1./(H(T4)-H1-0.4*CO1)
      RDH3=1./(H(T5)-H2+0.4*CO1)
      RDH4=1./(H(T6)-H2+0.1*CO1)
      CHAR=(RA/4.)*(RDH1+RDH2+RDH3+RDH4)
C          UNC - CHAR/FT OF PACKING FROM LOWE + CHRISTE
      UNC=0.1*(1./WART)**0.73
      PHT=CHAR/UNC
C     PPK-- DELTA P OF PACKING = 1.4 X VEL HEAD/FT  --- RISH AND STEEL
      PPK = 1.4*PHT
C      PSP--- DELTA P OF SPRAY
      PSP=0.16*( PHT+4.)*WART**1.32
C     INLET AND EXIT TURNING LOSSES AND FRICTION LOSS = 28.5 X VEL HEAD
      TPIX=28.5
      TPDP=PPK+PSP+TPIX
C           WACT - ACTUAL HUMIDITY
      WACT=RH*(0.622*P(TDB))/(14.696-P(TDB))
      APSAT=(WACT*14.696)/(0.622+WACT)
      DIN=144.*(14.696-APSAT)/(53.35*(TDB+460.))
      DOUT=(144.*(14.696-P(TAXT)))/(53.35*(TAXT+460.))
C           VIN - INLET VELOCITY
      VIN=5.
C          VHDI - INLET VEL HEAD
      VHDI=(VIN**2)*DIN/64.4
      DELP=TPDP*VHDI
      OPHT=(AFLR/3600.)/(PI*DIA*DIN*VIN)
C            SPRAY NOZZLES ASSUMED 4 FT ABOVE PACKING
      THT=DELP/(DIN-DOUT) + PHT + 4.0 + OPHT
      HTDIA = THT*DIA
      CAPCOS = 3.4E5*(HTDIA**.17)
      CONCR=5.
      TOUTS=.99674408E1+.24105952E1*H2-.22686654E-1*H2**2  +.10255304E-3
     X*H2**3-.14174090E-6*H2**4
      QLAT=QREJ-AFLR*.24*(TOUTS-TDB)
      WEVAP=QLAT/970.3
      WBDWN=(.06*QREJ*62.4)/(500.*7.48*(CONCR-1.))
```

```
      WNOG = 0.006*FLOW
      WNEED = WEVAP + WBDWN + WNOG
      HPPMP=((GPM*(PHT+4.+CPHT))/(3960.*PMPEF)
      OPCOS=(HPPMP*.7457/(PSIZE*1000.))*PWCST*USEFAC
      DELFC=DELFC*USEFAC
      COSMAI=.001*CAPCOS/(PSIZE*1000.)+.1*CFCOS+.01*SYSCST
      TOTCOS=(CAPCOS*ANFCR)/(PSIZE*1000.*CAPFAC*8.76) +OPCOS
     X +COSMAI+SYSCST+DELFC
      IF(TOTCOS-TOTCS1)154,156,156
156   IF(NSPCON.EQ.1)GO TO 157
      IF(NSYSOP.EQ.2)GO TO 151
      APPR=APPR+1.
      IF(APPR-20.)50,50,151
157   IF(NSYSOP.EQ.2)GO TO 190
151   TC=TC+1.
      IF(TC-TCMAX(NCAPS+1))100,100,190
154   RA1=RA
      CHAR1=CHAR
      PHT1=PHT
      AFLR1=AFLR
      APPR1=APPR
      HWB1=H1
      SYS1=SYSCST
      CAPCS1=CAPCOS
      COSPK1=COSPKW
      OPCS1=OPCOS
      COSMA1=COSMAI
      HPF1=0.0
      HPP1=HPPMP
      DELF1=DELFC
      QRJ1=QREJ
      QRJT1=QREJT
      FLOW1=FLOW
      GPM1=GPM
      WART1=WART
      UA1=UA
      WEVAP1=WEVAP
      WBDWN1=WBDWN
      WNEED1=WNEED
      TC1=TC
      DIA1=DIA
      THT1=THT
      TAXT1=TAXT
      OPHT1=OPHT
      TPDP1=TPDP
      DP1=DELP
      TOTCS1=TOTCOS
      WATER(NCO)=WNEED/224700. $ DISCH(NCO)=WBDWN1/224700.
      TDIS(NCO)=TOUTS $ CDIS(NCO)= CONCR $ CSC = TOTCS1 $ SPCC = 20.
      CCSC = CAPCS1
      GO TO 156
190   IF(TOTCS1-1.E3)200,195,200
195   WRITE(IRITE,196)TC,APPR,RA
196   FORMAT(/3X,    *FOR THE GIVEN CONDITIONS A SOLUTION CANNOT BE FOUN
     XD*,/,3X,*TC =*,F5.0,*     APPR =*,F5.0,*     RA =*,F5.0)
      GO TO 400
```

```
200  CONTINUE
     IF(IOO.EQ.1) GC TC 500
     WRITE(IRITE,212)
212  FORMAT(*1*,15X,*----- NATURAL DRAFT WET TOWER -----*,//, 10X,*
    XTHE DESIGN VALUES ANC COSTS ARE -*,//)
     CALL PRTUS1(CRJ1,TC1,HPF1,HPF1,WEVAP1,WBDWN1,AFLR1)
     WRITE(IRITE,227)LF1,FLCW1,RA1,APPR1,THT1,DIA1,CHAR1
227  FORMAT(3X,*PRESSURE DROP =*,F5.1,*    CCND FLOW =*,E12.4,/,3X*
    XRANGE =*,F4.0,*      APPROACH =*,F4.0,/,3X*TCWER HEIGHT =*,F6.0,
    X  *   TCWER DIAMETER =*F5.0/*   TOWER CHARACTERISTIC = *F5.2/)
     IF(NSYSOP-2)230,228,230
228  WRITE(IRITE,229)GRJT1
229  FORMAT(/3X,*C REJ TCWER =*,E12.4,* BTU/HR*)
230  CALL PRTUS2(CAPCS1,CPCS1,COSMA1,SYS1,DELF1,TCTCS1,CCSPK1)
300 CONTINUE
     WRITE(IRITE,330)
330  FORMAT(//15X,*VARIABLE AMBIENT CCNDITIONS*/)
500 IF(NTAMB.EQ.0)GO TO 400
     TOPMIL=0.0
     TDFMIL=0.0
     DO 350 I=1,NCAPS
     IF(CAP(I).EQ.0.)GC TC 350
     AMBOPC(I)=0.0
     AMBDFC(I)=0.0
     DO 340 J=1,NTAMB
     IF(PCTAMB(I,J).EG.0.)GO TC 340
     TC=TCMIN(I)
     NTCOD=0
301  CALL PAFCST(I,TC,PWCST,DFCOD,GREJ)
     DT2=(QREJ/FLCW1)/(EXP(UA1/FLOW1)-1.)
     DT1=DT2+GREJ/FLOW1
     T1=TC-DT2
     T2=TC-DT1
     IF(NSYSOP-2)316,303,316
316  IF(T2-TAMWB(J))304,304,302
303  IF(T2-TAMRV(J))304,305,306
305  NTCOD=1
306  T2=TDISMX
     IF(T2.GT.TAMWB(J))GC TC 302
     WRITE(IRITE,313)TAMWB(J)
313  FORMAT(3X*T DIS MAX LESS THAN(OR =) T WB =*     ,F4.0,/, 3X*REQUIR
    XES NEGATIVE APPRCACH - DISCONTINUING*)
     GO TO 400
302 TAXT=(T1+T2)/2.
     RA=T1-T2
     T3 = T2 + 0.1*RA
     T4 = T2 + 0.4*RA
     T5 = T1 - 0.4*RA
     T6 = T1 - 0.1*RA
     CO1 = WART1*RA
     H1=H(TAMWB(J))
     H2=H(TAXT)
     RDH1 = 1./(H(T3) - H1 - 0.1*CO1)
     RDH2 = 1./(H(T4) - H1 - 0.4*CO1)
     RDH3 = 1./(H(T5) - H2 + 0.4*CO1)
     RDH4 = 1./(H(T6) - H2 + 0.1*CO1)
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      CHAR = (RA/4.)*(RDH1 + RDH2 + RDH3 + RDH4)
      THT = 0.0
      IF(CHAR.LT.CHAR1) GO TO 320
321   IF(NSYSOP-2)304,307,304
307   WRITE(IRITE,308)CAP(I),TAMWB(J),TC, CHAR, THT
308   FORMAT(/8X*FOR CAP =*,F4.2,*,       T WB =*,F4.0,*, AND   TC =*
     X ,F4.0/3X,*(CHAR =*F5.2* THT = *F6.0*)*/*     T DIS EXCEEDS T DIS M
     3AX--CONTINUING*)
      GO TO 315
304   TC=TC+1.
      NTCOD=1
      IF(TC .LT. TCMAX(I))GO TO 301
      WRITE(IRITE,309)PCMAX(I),CAP(I),TAMWB(J)
309   FORMAT(/,3X,*CONDENSER PRESS MUST EXCEED THE GIVEN MAX OF*,/ 8
     XX,F4.2,* FOR THE CAPACITY OF*,F4.2,* AT T WET BULB =*,F5.0,/,3X,*P
     XROGRAM DISCONTINUING*)
      GO TO 400
320   WACT=AMBRH(J)*(.622*P(TAMDB(J)))/(14.696-P(TAMDB(J)))
      APSAT=WACT*14.696/(.622+WACT)
      DIN=144.*(14.696-APSAT)/(53.35*(TAMDB(J)+460.))
      DOUT=(144.*(14.696-P(TAXT)))/(53.35*(TAXT+460.))
      AFLR=QREJ/(H2-H1)
      VIN=(AFLR/3600.)/(PI*DIA1*OPHT1*DIN)
      VHDI=(VIN**2)*DIN/64.4
      THT=(TPDP*VHDI)/(DIN-DOUT) + PHT1 + 4.0 + OPHT1
      IF(THT - THT1) 310,310,321
310   IF(NTCOD.GT.0)GO TO 315
      IF(IOO.GT.1) PRINT 312, CAP(I), TAMWB(J), TC, CHAR, THT
312   FORMAT(/8X,*FOR CAP =*,F4.2,*,       T WB =*,F5.0,*,  AND   TC =*,
     X  F4.0/*  (CHAR = *F5.2* THT = *F6.0*)*/*     PC LESS THAN PC MIN
     3 ASSUME PC MIN -- CONTINUE*)
      IF(DFCOD.GT.0.)DFCOD=0.0
315   CONTINUE
      OPCOD=(HPP1*.7457/(PSIZE*1000.))*PWCST
      AMBOPC(I)=AMBOPC(I)+OPCOD*PCTAMB(J)
      AMBDFC(I)=AMBDFC(I)+DFCOD*PCTAMB(J)
340   CONTINUE
      TOPMIL=TOPMIL+AMBOPC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
      TDFMIL=TDFMIL+AMBDFC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
350   CONTINUE
      AVOPCS=TOPMIL/TKWHRS
      AVDFCS=TDFMIL/TKWHRS
      AVTCST=(CAPCS1*ANFCR)/(PSIZE*1000.*CAPFAC*8.76) +AVOPCS+AVDFCS+SYS
     X1+COSMA1
      IF(IOO.GT.1) CALL PRTOD(AVOPCS,AVDFCS,AVTCST)
      GO TO 400
400   CONTINUE
      RETURN
      END
```

```
      SUBROUTINE ONCE(NS,NT,NCO)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),   TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,   NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPIR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      WCOFA=0. $ WCOFB=15. $ PMPEF=0.8 $ TOTCS1=1.E3 $ TA=TDB $ TG=TCB
      SPCO = 0.0
C
C           CALCULATION OF THE EQULIBRIUM TEMPERATURE, TCALC, TO
C           STATEMENT 1 -- EQUATION TAKEN FROM EDINGER
      ECOF=WCOFA+WCOFB*WIND
      TA=TDB
      TG=TDB
    7 DH=RAD-1801.*(TG/460.+1.)**4-ECOF*51.7*(P(TG)-RH*P(TA)) -.26*ECO
     XF*(TG-TA)
      DHP=RAD-1801.*((TG+1.)/460.+1.)**4-ECOF*51.7*(P(TG+1.)-RH*P(TA)) -
     X.26*ECOF*(TG+1.-TA)
      DHM=RAD-1801.*((TG-1.)/460.+1.)**4-ECOF*51.7*(P(TG-1.)-RH*P(TA)) -
     X.26*ECOF*(TG-1.-TA)
      DHPRIM=(DHP-DHM)/2.
      IF(ABS(DH)-1.)1,2,2
    2 TNEW=TG-DH/DHPRIM
      TG=TNEW
      GO TO 7
    1 TCALC=TG
      BETA=51.7*(P(TCALC+1.)-P(TCALC-1.))/2.
      XK=15.7+(0.26+BETA)*ECOF
      TC=TCMIN(NCAPS+1)
  100 CONTINUE
      IF(NSPCON-1)30,40,30
   40 CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
      DT2=(QREJ/SPFLOW)/(EXP(UOVALL*AREAC/SPFLOW)-1.)
      DT1=DT2+QREJ/SPFLOW
      T1=TC-DT2
      T2=TC-DT1
      IF(NSYSOP-2)41,46,41
   41  IF(DT1-(TC-TAVH2O))45,45,151
   30 DT2=5.
      IF(NSYSOP-2)31,46,31
   31 T2=TAVH2O
      GO TO 51
   46 WRITE(IRITE,50)
   50 FORMAT(/*CANNOT HAVE TOPPING WITH STRAIGHT CONDENSER COOLING*/)
      GO TO 400
   51 CALL PAFCST(NCAPS+1,TC,PWCST,DELFC,QREJ)
   45 CALL COND(TC,T2,QREJ,PWCST,DT2,T1,UA,FLOW,GPM,SYSCST,
     * COSPKW)
      RA=T1-T2
      IF(NH2O)13,14,15
```

```
C          PLAC- COST PER KW FOR WATER DUCTING
   13  PLAC=1.5
      GO TO 16
   14  PLAC=1.25
      GO TO 16
   15  PLAC=1.0
   16  CONTINUE
      IF(NSPCON.EQ.1)PLAC=0.0
      SYSCST=SYSCST+PLAC*ANFCR/(CAPFAC*8.76)
C          ASSUME 5 FT OF PUMPING HEAD (FRICTION)
      PHEAD=5.
      HPPMP=GPM*PHEAD/(3960.*PMPEF)
      CAPCOS=0.0
C     CHANGE OPCOS STATEMENT TO MATCH EPA-- CORVALLIS VERSION ADD USEFAC
C     OPCOS=(HPPMP*.7457/(PSIZE*1000.))*PWCST
      OPCOS=(HPPMP*.7457/(PSIZE*1000.))*PWCST*USEFAC
      COSMAI=.001*CAPCOS/(PSIZE*1000.)+.1*OPCOS+.01*SYSCST
      TOTCOS=SYSCST+DELFC+OPCOS+COSMAI
      IF(TOTCOS-TOTCS1)154,156,156
  156  IF(NSPCON.EQ.1)GO TO 190
  151  TC=TC+1.
      IF(TC-TCMAX(NCAPS+1))100,100,190
  154  RA1=RA
      T11=T1 $ T21=T2 $ SYS1=SYSCST $ CAPCS1=CAPCOS $ COSPK1=COSKW
      OPCS1=OPCOS $ COSMA1=COSMAI $ PLAC1=PLAC $ HPF1=0. $ HPP1=HPPMP
      DELF1=DELFC $ TCALC1=TCALC $ QRJ1=QREJ $ FLOW1=FLOW $ GPM1=GPM
      FCFS=FLOW1/224700. $ UA1=UA $ TC1=TC $ TOTCS1=TOTCOS
      WATER(NCO) = FCFS $ DISCH(NCO)= FCFS $ TDIS(NCO) = T1
      CDIS(NCO)=1.0 $ CSC = TOTCS1 $ CCSC=CAPCS1  $ GO TO 156
  190  IF(TOTCS1-1.E3)200,195,200
  195  WRITE(IRITE,196)TC,T1,RA
  196  FORMAT(/3X,   *FOR THE GIVEN CONDITIONS A SOLUTION CANNOT BE FOUN
     XD*,/,3X,*TC =*,F5.0,*   T1 =*,F5.0,*    RA =*,F5.0)
      GO TO 400
  200  CONTINUE
      IF(IOO.LT.2) GO TO 23
      WRITE(IRITE,212)
  212  FORMAT(*1*15X*-----STRAIGHT CONDENSER COOLING-----*,/)
      IF(NH20)220,228,230
  220  WRITE(IRITE,197)
  197  FORMAT(20X*(WITH SEA WATER)*//)
      GO TO 23
  228  WRITE(IRITE,198)
  198  FORMAT(20X*(WITH UNTREATED FRESH WATER)*//)
      GO TO 23
  230   WRITE(IRITE,157)
  157  FORMAT(20X*(WITH TREATED FRESH WATER)*//)
   23 IF(IOO.GT.1) PRINT 227, QRJ1, TC1, FCFS, FLOW1, HPP1, TCALC1, RA1
  227  FORMAT(10X*THE DESIGN VALUES AND COSTS ARE -*,//,3X*Q REJECT = *,
     1E12.4, * BTU/HR  AT T CONDENSER =*,F4.0,/,3X*CONDENSER FLOW =*,E12
     2.4,* CFS (*,E12.4* LB/HR)*/,1H ,
     3       *    PUMP POWER =*,E12.4,  * HP*,/3X*EQUILIBRIUM TEMP =*F4.0
     X,*        RANGE =*,F4.0,/)
      IF(IOO.GT.1) CALL PRTOS2(CAPCS1,OPCS1,COSMA1,SYS1,DELF1,TOTCS1,COS
     2PK1)
      IF(IOO.GT.1) PRINT 302
```

```
 302  FORMAT(//15X*--RIVER TEMPERATURES--*,//,
     X1X,14HDISTANCE-MILES,3X,17HSTREAM TEMP DEG.F, 3X,17HPLUME TEMP.-DE
     XG.F ,3X,14HPLUME WIDTH-MI,/19X,8HNO PLANT,2X,5HMIXED,//)
C          CALC OF PLUME TEMPS AND WIDTH AND RIVER TEMPS- TO STAT 22
      VELRIV=(QFLRIV/(WIDTH*DEPTH))*3600.*24.
      DTRIV=(QRJ1/QFLRIV)/(3600.*62.4)
      TZERO=TAVH20+DTRIV
      I=-1
 307  I=I+1
      IF(I.EQ.11)I=20
      XI=I
      QCON=FLOW1/(3600.*62.4)
      C1=ALOG((QFLRIV/(QFLRIV-QCON))
      PLUMEW=WIDTH*(1.-EXP(-(XI/2.+C1)))
      ALPHA1=-((XK*XI*5280.)/(62.4*DEPTH*VELRIV))
      TXDIST=((TZERO-TCALC)*EXP(ALPHA1)+TCALC
      TWREAL=(TAVH20-TCALC)*EXP(ALPHA1)+TCALC
      PLUMEW=PLUMEW/5280.
      PLUMT=((TXDIST-TWREAL)/(1.-EXP(-(XI/2.+C1))))+TWREAL
      IF(IOO.GT.1) PRINT 308, XI, TWREAL, TXDIST, PLUMT, PLUMEW
 308  FORMAT((6X,F5.1,6X,F6.2,4X,F6.2,5X,F6.2,11X,F6.4)
      IF(I.LT.20)GO TO 307
      IF(IOO.GT.1) PRINT 330
 330  FORMAT(//15X,*VARIABLE AMBIENT CONDITIONS*/)
      IF(NTAMB.EQ.0)GO TO 400
      TOPMIL=0.0
      TOFMIL=0.0
      DO 350 I=1,NCAPS
      IF(CAP(I).EQ.0.)GO TO 350
      AMBOPC(I)=0.0
      AMBOFC(I)=0.0
      DO 340 J=1,NTAMB
      IF(PCTAMB(I,J).EQ.0.)GO TO 340
      TC=TCMIN(I)
      NTCOD=0
 301  CALL PAFCST(I,TC,PWCST,OFCOD,QREJ)
      DT2=(QREJ/FLOW1)/(EXP(UA1/FLOW1)-1.)
      DT1=DT2+QREJ/FLOW1
      T1=TC-DT2
      T2=TC-DT1
      IF(T2-TAMRV(J))304,305,310
 305  NTCOD=1
      GO TO 310
 304  TC=TC+1.
      NTCOD=1
      IF(TC .LT. TCMAX(I))GO TO 301
      WRITE(IRITE,309)PCMAX(I),CAP(I),TAMWB(J)
 309  FORMAT(/,3X,*CONDENSER PRESS MUST EXCEED THE GIVEN MAX OF*,/ 8
     XX,F4.2,* FOR THE CAPACITY OF*,F4.2,* AT T WET BULB =*,F5.0,/,3X,*P
     XROGRAM DISCONTINUING*)
      GO TO 400
 310  IF(NTCOD.GT.0)GO TO 315
      IF(IOO.GT.1) PRINT 312, CAP(I), TAMWB(J), TC
 312  FORMAT(/8X,*FOR CAP =*,F4.2,*,     T WB =*,F5.0,*,  AND  TC =*,
     XF4.0,/,3X*PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE*)
      IF(OFCOD.GT.0.)OFCOD=0.0
```

```
315  CONTINUE
     OPCOD=(HPP1*.7457/(PSIZE*1000.))*PWCST
     AMBOPC(I)=AMBOPC(I)+OPCOD*PCTAMB(J)
     AMBOFC(I)=AMBOFC(I)+OFCOD*PCTAMB(J)
340  CONTINUE
     TOPMIL=TOPMIL+AMBOPC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
     TOFMIL=TOFMIL+AMBOFC(I)*TOTLD(I)*COLPCT(I)*CAP(I)
350  CONTINUE
     AVOPCS=TOPMIL/TKWHRS
     AVOFCS=TOFMIL/TKWHRS
     AVTCST=AVOPCS+AVOFCS+SYS1+COSMA1
     IF(IOO.GT.1) CALL PRTOD(AVOPCS,AVOFCS,AVTCST)
400  CONTINUE
     RETURN
     END
```

```
      SUBROUTINE TRANS(NS,NTR,NT)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), CCLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),     FLCW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
    1 FORMAT(*4      RESULTS OF TRANSMISSION COST CALCULATIONS FOR SITE N
     2UMBER *I3,/*  WITH PLANT TYPE *I3,//,25X,* CAPITAL COSTS *10X* COS
     3T PER UNIT POWER */,28X,* (DOLLARS) *15X* (MILLS/KW-HR) */* TRANSM
     4ISSION OPTION IS *I2,/)
    2 FORMAT(*  NEW TRANSMISSION LINES */*0 CONSTRUCTION COST *8X,E9.2,
     218X,E9.2,   /*  MAINTENANCE COST  *8X,E9.2,18X,E9.2/*  NEW TRANS T
     3OTAL COST*33X,E9.2//*  LOAD CENTER RELATED COSTS */*  WHEELING COS
     4T(BPA)*35X,E9.2//*  TOTAL TRANSMISSION COSTS AT THIS SITE ARE *E9.
     52* MILLS/KW-HR. *//)
      D = PSIZE*1.E3*CAPFAC*8.76
      R = PSIZE/1000.
      CCOST = DISTR(NTR)*R*CCPM(NTR)
      OMCOST = DISTR(NTR)*R*YOPCM(NTR)
      UCC = CCOST*ANFCR/D
      UOC = OMCOST/D
      TC = UCC + UOC
C     CALCULATE COST IN MILLS/KW-HR FOR TRANSMISSION OF POWER TO LOAD
C     CENTER USING THE BPA WHEELING FORMULA
      TPEN = (DISLC(NTR)*TMCST(NTR) + 0.81)/8.76
      TRCST = TPEN + TC
C
C     LAND USE CALCULATION FOR 500 KV TRANSMISSION LINES8 FOR 1000 MW
C     ASSUME CORRIDOR IS 175 FT WIDE
C
      SPNC = (DISTR(NTR)*5280.*175.)/43560.
      SPTR = (DISLC(NTR)*5280.*175.)/43560.
      IF(IOO.EQ.1) GO TO 10
      PRINT 1, NS,NT,NTR
      PRINT 2, CCOST, UCC, OMCOST, UOC, TC, TPEN, TRCST
   10 RETURN
      END
```

```
      SUBROUTINE SLDWST(NS,NT,NCO,NSC,NCH,NP)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,IKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
C
C     SLDWST IS A SUBROUTINE WHICH CALCULATES SOLID WASTE GENERATED BY
C     A FOSSIL FIRED POWER PLANT(COAL).  THE SUBROUTINE GIVES
C     INFORMATION ON BASELINE SOLID WASTES GENERATED AND THE EXTRA
C     BURDEN CAUSED BY EXTRA FUEL CONSUMPTION FROM THE USE OF NON-ONCE
C     THRU COOLING.  BASE HEAT RATE IS ASSUNED TO BE 7200 BTU/KWHR.
C
    1 FORMAT(*0   BASELINE SOLID WASTE LOAD IS *F7.2* LB/KW-HR*/*   THIS
     2 AMOUNTS TO GENERATING *E9.2* LB/HR OF SOLID WASTE FOR THIS PLANT*
     3)
    2 FORMAT(*0   SOLID WASTE GENERATED BY THIS OPTION IS *F7.2* LB/KW-H
     2R*/*    THIS AMOUNTS TO GENERATING *E9.2* LB/HR OF SOLID WASTE.*/)
    3 FORMAT(*0   THE NUCLEAR FUEL SYSTEM IS A CLOSED LOOP.*/* NO FUEL S
     2OLID WASTE IS HANDLED AS A SEPARATE, EXTERNAL PROBLEM.*/* ALL FUEL
     3COSTS(INCLUDING SOLID WASTE ARE INTERNALIZED IN FUEL PRICE)*/)
C
      SWGB = 0.24
      SWGBH = 0.24*CAPFAC*PSIZE*1000.
      SWG = 0.24*(7200. + DELHR)/7200.
      SWGH = SWG*CAPFAC*PSIZE*1000.
      IF(NCO.EQ.1.AND.NT.EQ.2) PRINT 1, SWGB, SWGBH
      IF(NCO.NE.1.AND.NT.EQ.2) PRINT 2, SWG, SWGH
      IF(NT.EQ.1) PRINT 3
C     COOLING SYSTEM SOLID WASTE GENERATION WILL BE ADDED FOR LATER VERS
C     COOLING SYSTEM SOLID WASTE GENERATION WILL BE ADDED FOR LATER
C     VERSION OF THE PROGRAM.  DATA IS INCOMPLETE AT THIS TIME
      RETURN
      END
```

```
      FUNCTION H(T)
      H   =21.572142-.93539227*T+.28365243E-01*T**2 -.26605772E-03*T**3+
     X.12608996E-05*T**4
      RETURN
      END

      FUNCTION P(T)
      P   =.16818166E-1+.14461089E-2*T+.83460247E-5*T**2+.4987537E-6
     X *T**3-.20658843E-9*T**4+.22620224E-10*T**5
      RETURN
      END


      SUBROUTINE PRTOD(OPCOD,DFCOD,TCOD)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      WRITE(IRITE,10) OPCOD,DFCOD,TCOD
   10 FORMAT(/5X,*WITH THE VARIOUS AMBIENT TEMPERATURES*,/,
     X 5X,*THE COSTS ARE -*,//,
     X 3X,*OPERATING COST =*,F6.3,* MILLS/KW-HR*,/,
     X 3X,*DIFFERENTIAL FUEL COST =*,F6.3,* MILLS/KW-HR*,/,
     X /,3X,*TOTAL SYSTEM COST =*,F6.3,* MILLS/KW-HR*)
      RETURN
      END


      SUBROUTINE PRTDS2(CAPCOS,OPCOS,COSMAI,SYSCOS,DELFC,TOTCCS,COSPKW)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      WRITE(IRITE,10) CAPCOS,COSPKW,OPCOS,COSMAI,SYSCOS,DELFC,TOTCOS
   10 FORMAT(*0  CAPITAL COST =*,E12.4,* DOLLARS*/*   CONDENSER AND PUMP
     1COST =*,E12.4,* DOLLARS/KW*/*   OPERATING COST =*,
     X        F6.3,* MILLS/KW-HR*,/, 3X,*MAINTENANCE COST =*,F6.3,* MILLS
     X/KW-HR*,/, 3X,*CONDENSER SYSTEM COST =*,F6.3,* MILLS/KW-HR*,/, 3X,
     X*DIFFERENTIAL FUEL COST =*,F6.3,* MILLS/KW-HR*,//, 3X,*  TOTAL SYS
     XTEM COST =*,F6.3,* MILLS/KW-HR*/)
      RETURN
      END
```

```
      SUBROUTINE PRTDS1(QREJ,TC,HPF,HPP,WEV,WBD,AFLR)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOILD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2C,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,DOVALL,A
     XREAC,SPFLOW,  NH20,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLCW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,IZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCC, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      WEVCFS=WEV/224700.
      WBDCFS=WBD/224700.
      WRITE(IRITE,10)QREJ,TC,HPF,HPP,WEVCFS,WEV,WBDCFS,WBD,AFLR
   10 FORMAT(/,3X,*Q REJECT =*,E12.4,* BTU/HR  AT T CONDENSER =*, F5.0
     1,/,3X,*FAN POWER =*,E12.4,*HP  PUMP POWER =*,E12.4,*HP*,/,3X,*
     2H2O EVAP =*,E12.4,* CFS (*,E12.4,*LB/HR)*/
     3 *   H2O BLOWDOWN =*,E12.4,* CFS (*,E12.4,* LB/HR)*/
     4 *   AIR FLOW RATE =*,E12.4,* LB/HR*)
      RETURN
      END
```

```
 SUBROUTINE PAFCST(I,TC,PWCST,DELFC,QREJ)
 COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
 COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
 HRBASE=HRCOF2(I)*TCBASE**2+HRCOF1(I)*TCBASE+HRCOF0(I)
 HEATR=HRCOF2(I)*TC**2+HRCOF1(I)*TC+HRCOF0(I)
 QREJ=(HEATR-3413.)*PSIZE*CAP(I)*1000.
 DELHR=HEATR-HRBASE
 DELFC=FUCST*DELHR*1.E-5
 PWCST=FUCST*HEATR*1.E-5+(CCPKW*ANFCR)/(CAPFAC*8.76)
 RETURN
 END
```

```
      SUBROUTINE COND(TCOND,TIN,QREJ,PWCST,DT2,TOUT,UA,FLOW,GPM,
     1  SYSCST,COSPKW)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC
      PMPEF=.8
      IF(NSPCON.EQ.1)GO TO 30
C           VARIATION OF HEAT TRANSFER COEFFICIENT, UALL, WITH TYPE
C           OF  WATER
      IF(NH2O)20,10,15
   10  UALL=340.
      GO TO 25
   15  UALL=420.
      GO TO 25
   20  UALL=250.
   25  CONTINUE
      DT1=TCOND-TIN
      TOUT=TCOND-DT2
      DELT=TOUT-TIN
C           ALOG MEAN TEMPERATURE DIFFERENCE, LMTD
      DTLGM=(DT1-DT2)/(ALOG(DT1/DT2))
      ACOND=QREJ/(DTLGM*UALL)
      UA=UALL*ACOND
      CONCST=20.*(ACOND*1.05)**.9
C           65 PERCENT INCREASE IN MATERIAL COSTS IF SALT WATER USED
      IF(NH2O.LT.0)CONCST=CONCST*1.65
      FLOW=QREJ/DELT
      GPM=FLOW/(8.34*60.)
C         ASSUME 35 FT OF HEAD
      CHEAD=35.
      PMPCST=(GPM*CHEAD*.7457*PWCST)/(3960.*PMPEF*PSIZE*1000.)
C           1 DOLLAR PER GPM FOR COST  OF PUMPS
      COSPKW=(CONCST+1.*GPM)/(PSIZE*1.E3)
      SYSCST=((COSPKW*ANFCR)/(CAPFAC*8.76)+PMPCST
      GO TO 50
   30  UA=UOVALL*AREAC
      FLOW=SPFLOW
      GPM=FLOW/(8.34*60.)
      SYSCST=0.0
   50  RETURN
      END
```

```
      SUBROUTINE SCREENS(NS,NT,NCO,NSC)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), CCLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBOFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      DIMENSION NAME(4)
      DATA(NAME(I),I=1,4)/10HONCE-THRU ,10HPOND      , 10HNATDFT TWR,
     210HMECHDFT TR/
    1 FORMAT(*0     THE SCREENING COSTS ARE */*0  CAPITAL COSTS * E9.2
     2*MILLS/KWHR*/ *   OPERATING COSTS*E9.2*MILLS/KWHR*/*  TOTAL COSTS
     3ARE*E9.2*  MILLS/KWHR*/)
    2 FORMAT(*0  INTAKE COSTS WITHOUT SCREENING*//
     2*  CAPITAL COST*E9.2* MILLS/KWHR* /*  OPERATING COSTS *E9.2      *
     3MILLS/KWHR*//*  TOTAL SYSTEM COST IS*  E9.2* MILLS/KWHR*/)
    3 FORMAT(*0  THE SCREENING DAMAGE TO FISH HAS A VALUE OF *E9.2* MILL
     2S/KW-HR*/*   COMPARED TO SCREENING COSTS OF *E9.2* MILLS/KW-HR*/)
    4 FORMAT(*1    SCREENING CALCULATIONS FOR *A10*   COOLING*/*    THE
     2FLOW TO BE CONSIDERED FOR SCREENING IS *E9.2* CFS.*)
      FLOI = WATER(NCO)
      IF(IOO.NE.1) PRINT 4, NAME(NCO), FLOI
      F2= 0.
      IF(FLOI.LT.500.) F1 = 1000.
      IF (FLOI.GE.500.) F1 = 240.
      IF(FLOI.LT.10.) GO TO 8
      GO TO 10
    8 F2=8.0E3$F1=0.
C      COMPUTE CAPITAL COSTS FOR A SCREENED INSTALLATION
   10 CCOSTS = F1*FLOI + F2
C     COMPUTE COST PER UNIT ENERGY GENERATED
      D = PSIZE*1.E3*CAPFAC*8.76
      CCPUP = CCOSTS*ANFCR/D
C     THE MAINTENANCE FACTOR IS TAKEN TO BE 10 PER CENT OF THE CAP CST
      OCPUP = 0.01*CCOSTS/D
      TCST = CCPUP + OCPUP
      IF(IOO.NE.1) PRINT 1, CCPUP, OCPUP, TCST
C     INTAKE COSTS WITHOUT SCREENS ARE 60 PERCENT OF THOSE WITH SCREENS
      X2=0.6*CCPUP $ X3=0.6*OCPUP$ X4= X2 + X3
      IF(IOO.NE.1) PRINT 2, X2, X3, X4
C     ASSUME FISH DAMAGE IS PROPORTIONAL TO THE FRACTION OF RIVER WATER
C     FUNCTION OF THE RIVER ON WHICH THE PLANT IS LOCATED.
C     PUMPED THROUGH THE PLANT.  SCREENING PREVENTS ALL FISH DAMAGE IN
      R = FLOI/QFLRIV
      DAM = R*FISH
      DAMP = DAM/D
      IF(NSC.EQ.1) SSC=0.6*TCST
      IF(NSC.EQ.1) CFISH = DAMP
      IF(NSC.EQ.2) SSC = TCST
      IF(NSC.EQ.2) CFISH = 0.0
      IF(IOO.NE.1) PRINT 3, DAMP, TCST

      RETURN
      END
```

```
      SUBROUTINE CHEM(NS,NT,NCO,NSC,NCH)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), CCLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),   TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,   NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPIR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
C     SELECT TREATMENT PROCESS BASED ON COOLING TYPE AND TREATMENT FLAG
      GO TO(100,100,200,200) NCO
C     ESTABLISH TREATMENT COSTS FOR SYSTEMS UTILIZING CHLORINATION
C     ONLY(PONDS AND ONCE-THRU)
C     CONVERT FLOW TO MGD.
  100 FL = (FLOW1*2.89)/1.E6
C     CALCULATE CAPITAL COST
      CAPC = (0.015*FL**.67)*1.E6
      OUTPUT,CAPC,FL,FLOW1
C     O AND M CURVE IS VERY NEARLY FLAT PICK A VALUE OF .07 $/1000.
C     GAL AND GENERATE O + M FOR FLOWRATE
C     CONVERT BOTH COSTS TO PER UNIT POWER COSTS AND ADD FOR TOTAL
      UCAP = CAPC*1000.*ANFCR/TKWHRS
      UOP = 0.07*FL*0.01/24.
      CHSC = UCAP + UOP
      OUTPUT, UCAP,UOP,CHSC
      GO TO 500
C     ESTABLISH TREATMENT COSTS FOR TOWER SYSTEMS  FOR THIS CASE TREAT
C      MENT IS ASSUMED TO CONSIST OF COAGULATION AND SEDIMENTATION
C      PLUS SAND FILTRATION
C     NO TREATMENT IF NCH = 1
  200 IF(NCH.EQ.1) GO TO 400
C     CONVERT BLOWDOWN TO MGD
      FL = DISCH(NCO)/1.55
C     COMPUTE COST(CENTS/1000. GAL)
      TC = 4./(FL**.02)   +   8./(FL**.4)
C     CONVERT COST TO MILLS/KW-HR
      CHSC = TC*FL*0.01/24.
      OUTPUT,DISCH(NCO),FL,TC,CHSC
      GO TO 500
  400 CHSC = 0.0
  500 RETURN
      END
```

```
      SUBROUTINE PLANT(NS,NTR,NT,IPF)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,IZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      DIMENSION NHRPTS(6),HRP(6,6),THR(6,6),TURBHR(6,6), HR(6,6)
      NAMELIST/PLPARM/ PSIZE, CCPKW, FUCST, SPGR, NCAPS
      NAMELIST/CAPTURL/ CAP, TOTLD, COLPCT, NHRPTS, PCMIN, PCMAX
      NAMELIST/TUROPD/ HRP, TURBHR, PCBASE, PCTAMB
      NAMELIST/SYSDTA/ NSYSOP, NSPCON, UOVALL, AREAC, SPFLOW
      IF(IPF.EQ.0) GO TO 90
      READ(IREAD, PLPARM)
      NCAPS1=NCAPS+1
C
      READ(IREAD,CAPTURL)
      NNCAP=NCAPS
      IF(NHRPTS(NCAPS1) .GT. 0) NNCAP=NNCAP+1
      READ(IREAD,TUROPD)
C
      READ(IREAD,SYSDTA)
      GO TO 100
C
C     SELECT POWER PLANT INPUT INFORMATION BASED ON EITHER DEFAULT OR
C     INPUT FLAG INFORMATION
C     DEFAULT INPUT INFORMATION FOR NUCLEAR POWER PLANT
C
   90 GO TO(91,92) NT
   91 PSIZE=1000. $ CCPKW=250. $ ANFCR=0.10 $ FUCST=20.
      TURBHR(1,1)=9765. $ TURBHR(1,2)=9815. $ TURBHR(1,3)=9865.
      TURBHR(2,1)=9815. $ TURBHR(2,2)=9915. $ TURBHR(2,3)=10300.
      TURBHR(3,1)=9815. $ TURBHR(3,2)=9915. $ TURBHR(3,3)=10300.
      TURBHR(4,1)=9815. $ TURBHR(4,2)=9915. $ TURBHR(4,3)=10300.
      TURBHR(5,1)=    0. $ TURBHR(5,2)=    0. $ TURBHR(4,3)=    0.0
      TURBHR(5,1)=    0. $ TURBHR(5,2)=    0. $ TURBHR(5,3)=    0.0
       SPGR = 500. $ HRBASE = 9815. $ PNAME(NT)= 7HNUCLEAR
      GO TO 99
C
C     FOSSIL FIRED(COAL) DEFAULT INPUT DATA
C
   92 PSIZE = 1000. $ CCPKW = 190. $ ANFCR = 0.10 $ FUCST = 27.
      TURBHR(1,1)=7200. $ TURBHR(1,2)=7220. $ TURBHR(1,3)=7250.
      TURBHR(2,1)=7220. $ TURBHR(2,2)=7280. $ TURBHR(2,3)=7350.
      TURBHR(3,1)=7220. $ TURBHR(3,2)=7280. $ TURBHR(3,3)=7350.
      TURBHR(4,1)=7220. $ TURBHR(4,2)=7280. $ TURBHR(4,3)=7350.
      TURBHR(5,1)=    0. $ TURBHR(5,2)=    0. $ TURBHR(5,3)=    0.
      SPGR = 300. $ HRBASE = 7220. $ PNAME(NT) = 7H FOSSIL
   99 NSYSOP=0 $ NSPCON=0 $ NCAPS1=6 $ NCAPS = 5 $ PCBASE = 1.5
      CAP(1)=1.0 $ CAP(2)=0.8 $ CAP(3)=0.6 $ CAP(4)=0.25 $ CAP(5)=0.0
      TOTLD(5)=360.
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```
      TOTLD(1)=6450. $ TOTLD(2)=750. $ TOTLD(3)=700. $ TOTLD(4)=500.
      COLPCT(1)=1.0 $ COLPCT(2)=1.0 $ COLPCT(3)=1.0 $ COLPCT(4)=1.0
      COLPCT(5)=1.0
      PCMIN(1)=1.0 $ PCMIN(2)=1.5 $ PCMIN(3)=1.5 $ PCMIN(4)=1.5
      PCMIN(5)=1.5 $ PCMIN(6)=0.0
      PCMAX(1)=2.0 $ PCMAX(2)=3.5 $ PCMAX(3)=3.5 $ PCMAX(4)=3.5
      PCMAX(5)=3.5 $ PCMAX(6)=0.0
      NHRPTS(1)=3 $ NHRPTS(2)=3 $ NHRPTS(3)=3 $ NHRPTS(4)=3
      NHRPTS(5)=3 $ NHRPTS(6)=0
      PCTAMB(1,1)=0.5 $ PCTAMB(1,2)=0.1 $ PCTAMB(1,3)=0.2
      PCTAMB(1,4)=0.2
      PCTAMB(2,1)=0.1 $ PCTAMB(2,2)=0.4 $ PCTAMB(2,3)=0.4
      PCTAMB(2,4)=0.1
      PCTAMB(3,1)=0.2 $ PCTAMB(3,2)=0.4 $ PCTAMB(3,3)=0.3
      PCTAMB(3,4)=0.1
      PCTAMB(4,1)=0.3 $ PCTAMB(4,2)=0.1 $ PCTAMB(4,3)=0.4
      PCTAMB(4,4)=0.2
      PCTAMB(5,1)=1.0 $ PCTAMB(5,2)=0.0 $ PCTAMB(5,3)=0.0
      PCTAMB(5,4)=0.0
      HRP(1,1)=1.0 $ HRP(1,2)=1.5 $ HRP(1,3)=2.0
      HRP(2,1)=1.5 $ HRP(2,2)=2.5 $ HRP(2,3)=3.5
      HRP(3,1)=1.5 $ HRP(3,2)=2.5 $ HRP(3,3)=3.5
      HRP(4,1)=1.5 $ HRP(4,2)=2.5 $ HRP(4,3)=3.5
      HRP(5,1)=1.5 $ HRP(5,2)=2.5 $ HRP(5,3)=3.5
C
C           LOAD DURATION HOURS CHECK - TO STATEMENT 246
  100 TOTDUR = 0.0
      DO 243 I=1,NCAPS
      TOTAM=0.0
C           PERCENT AMBIENT TIME CHECK - TO STATEMENT 242
      DO 238 J=1,NTAMB
  238  TOTAM=TOTAM+PCTAMB(I,J)
      IF( TOTAM .EQ. 1.) GO TO 242
      WRITE(IRITE,239) I
  239  FORMAT(* TOT PCT AMBIENT HRS NOT = 1.0 FOR CAP NO*,I2)
      GO TO 500
  242  CONTINUE
      TOTDUR=TOTDUR+TOTLD(I)
  243  CONTINUE
      IF (TOTDUR .EQ. 8760.)GO TO 246
      WRITE(IRITE,244)
  244  FORMAT(* TOT LD HRS NOT = 8760 *)
      GO TO 500
  246 CONTINUE
C
C           CALC OF RELATIVE HUMIDITY - RH AND AMBRH
      PBAR=14.696
      PV=P(TWB)-(((PBAR-P(TWB))*(TDB-TWB))/(2800.-1.3*TWB))
      RH=PV/P(TDB)
      DO 20 I=1,NTAMB
   20  AMBRH(I)=(P(TAMWB(I))-(((PBAR-P(TAMWB(I)))*
     X ((TAMDB(I)-TAMWB(I)))/(2831.-1.43*TAMWB(I)))))/P(TAMDB(I))
C
C           QUADRADIC CURVE FIT OF HEAT RATES (TO STATEMENT 9)
      NNCAP=NCAPS $ CAP(NCAPS1)=1.
      IF(NHRPTS(NCAPS1) .GT. 0) NNCAP=NNCAP+1
```

```
      DO 9 I=1,NNCAP
      IF(NHRPTS(I) .GT. 2) GO TO 7
      WRITE(IRITE,6)I
    6 FORMAT(* LESS THAN 3 HEAT RATES FOR CAP NO *,I2)
      GO TO 500
    7 X1=0.$X2=0.$X3=0.$X4=0.$XY=0.$X2Y=0.$Y1=0.
      M2=NHRPTS(I)
      DO 8 J=1,M2
C
      HR(I,J)=TURBHR(I,J)
C
C          CALC OF TSAT FROM PRESS. (IN. HG)
      BLOG=ALOG(HRP(I,J))
      THR(I,J)=79.035793+30.462409*BLOG+1.9740416*
     X (BLOG)**2+0.13124035*(BLOG)**3
      X1=THR(I,J)+X1
      X2=(THR(I,J)**2)+X2
      Y1=HR(I,J)+Y1
      X3=(THR(I,J)**3)+X3
      X4=(THR(I,J)**4)+X4
      XY=XY+THR(I,J)*HR(I,J)
    8 X2Y=X2Y+(THR(I,J)**2)*HR(I,J)
      B=NHRPTS(I)
      DEN=X4*(B*X2-X1**2)-X3*(B*X3-X2*X1)+X2*(X3*X1-X2**2)
      ANUM=X2Y*(B*X2-X1**2)-X3*(B*XY-X1*Y1)+X2*(XY*X1-X2*Y1)
      BNUM=X4*(B*XY-X1*Y1)-X2Y*(B*X3-X2*X1)+X2*(X3*Y1-XY*X2)
      CNUM=X4*(X2*Y1-XY*X1)-X3*(X3*Y1-XY*X2)+X2Y*(X3*X1-X2**2)
      HRCOF2(I)=ANUM/DEN
      HRCOF1(I)=BNUM/DEN
      HRCOF0(I)=CNUM/DEN
    9 CONTINUE
C
C          MAKING DESIGN HR = 100PCT CAPACITY HR (IF NOT SPECIFIED)
      IF(NHRPTS(NCAPS1) .GT. 0) GO TO 45
      DO 40 I=1,NCAPS
      IF(CAP(I) .EQ. 1.) GO TO 42
   40 CONTINUE
      WRITE(IRITE,41)
   41 FORMAT(* NO 100 PCT CAPACITY OR DESIGN HR*)
      GO TO 500
   42 HRCOF2(NCAPS1)=HRCOF2(I)
      HRCOF1(NCAPS1) = HRCOF1(I)
      HRCOF0(NCAPS1) = HRCOF0(I)
      PCMIN(NCAPS1)=PCMIN(I) $ PCMAX(NCAPS1)=PCMAX(I)
   45 CONTINUE
C
      DO 11 I=1,NCAPS1
      BLOG=ALOG(PCMIN(I))
      TCMIN(I)=79.035793+30.462409*BLOG+1.9740416*
     X (BLOG)**2+0.13124035*(BLOG)**3
      BLOG=ALOG(PCMAX(I))
   11  TCMAX(I)=79.035793+30.462409*BLOG+1.9740416*
     X (BLOG)**2+0.13124035*(BLOG)**3
      BLOG=ALOG(PCBASE)
      TCBASE=79.035793+30.462409*BLOG+1.9740416*
     X (BLOG)**2+0.13124035*(BLOG)**3
```

```
C
C          CALC OF AVG CAPACITY FACTOR AND COOLING USE FACTOR
      TKWHRS=0.0 $ CKWHRS=0.0
      DO 47 I=1,NCAPS
      TKWHRS=TKWHRS+(CAP(I)*TOTLD(I))
   47  CKWHRS=CKWHRS+(CAP(I)*TOTLD(I)*COLPCT(I))
      CAPFAC=TKWHRS/8760. $ USEFAC=CKWHRS/TKWHRS
C
C
      IF(IOO.EQ.3) PRINT 350, PSIZE, CCPKW, ANFCR, FUCST, PNAME(NT)
  350 FORMAT(1H1,10X,*-----PRINTOUT OF POWER PLANT DATA-----*
     2/*0     PSIZE(MWE) CAP CST($/KW)  ANFCR(FR) FUEL COST(CTS/MILLION BT
     3U)    TYPE*/,5X,F5.0,3X,F9.0,6X,F8.3,F9.0,15X,A7//)
      IF(IPF.EQ.0) PRINT 1000
 1000 FORMAT(*0-----NOTE  POWER PLANT DATA SPECIFIED IS INTERNAL DATA*/*
     2         NO POWER PLANT DATA WERE INPUT.*///)
      IF(IOO.NE.3) GO TO 500
C
      WRITE(IRITE,360)(CAP(I),I=1,NCAPS)
      WRITE(IRITE,361)(TOTLD(I),I=1,NCAPS)
      WRITE(IRITE,362)(COLPCT(I),I=1,NCAPS)
      WRITE(IRITE,363)(PCMIN(I),I=1,NCAPS1)
      WRITE(IRITE,364)(TCMIN(I),I=1,NCAPS1)
      WRITE(IRITE,365)(PCMAX(I),I=1,NCAPS1)
      WRITE(IRITE,366)(TCMAX(I),I=1,NCAPS1)
  360  FORMAT(5X,*CAPACITIES AND CORRESPONDING DATA*,/, 7X,    *(EXTRA V
     XALUES ARE DESIGN DATA)*,//, 3X,*CAPACITY -    *,5F7.2)
  361 FORMAT(*     HRS/YEAR -      *,5F7.0)
  362 FORMAT(*     PCT COOLING -  *,5F7.2)
  363 FORMAT(*     MIN P COND -    *,6F7.2)
  364 FORMAT(*     MIN T COND -    *,6F7.2)
  365 FORMAT(*     MAX P COND -    *,6F7.2)
  366 FORMAT(*     MAX T COND -    *,6F7.2)
C
      WRITE(IRITE,370)CAPFAC,USEFAC
  370  FORMAT(5X,*CAPACITY FACTOR =*,F5.2,/,5X,*COOLING USE FACTOR =*
     X ,F5.2,//)
C
      WRITE(IRITE,403)
  403  FORMAT(5X,*COND PRESS AND CORRESPONDING DATA AT EACH CAPACITY
     X*)
      DO 407  I=1,NCAPS
      WRITE(IRITE,404) CAP(I)
  404  FORMAT(/2X,*CAPACITY =*,F4.2)
C
      M2=NHRP1S(I)
      WRITE(IRITE,405) (HRP(I,J),J=1,M2)
  405  FORMAT(3X,*PRESSURE -     *,6F8.2)
C
  407 WRITE(IRITE,406) (TURBHR(I,J),J=1,M2)
  406  FORMAT(3X,*T HEAT RATE -  *,6F8.0)
C
      M2=NHRP1S(NCAPS1)
      IF(M2 .EQ. 0) GO TO 412
      WRITE(IRITE,409)(HRP(NCAPS1,J),J=1,M2)
  409  FORMAT(//5X,*DESIGN VALUES (CAPACITY = PLANT SIZE)*,//, 3X,    *PR
```

```
     XESSURE -      *,6F8.2,/)
      WRITE(IRITE,410)(TURBHR(NCAPS1,J),J=1,M2)
  410  FORMAT(3X,*T HEAT RATE -  *,6F8.0,/)
C
C
  412 WRITE(IRITE,429)PCBASE,TCBASE
  429  FORMAT(3X,*BASE P COND       BASE T COND*,/,7X,F6.2,8X,F6.1//)
C
      WRITE(IRITE,417)
  417  FORMAT(//5X,*PERCENT OF COOLING SYSTEM TIME AT ABOVE*,/,
     X 8X,*AMBIENT CONDITIONS*,/)
      DO 418  I=1,NCAPS
  418  WRITE(IRITE,419)CAP(I),(PCTAMB(I,J),J=1,NTAMB)
  419  FORMAT(/3X,*CAP = *,F4.2,* -*,5F7.2)
C
C
  424 IF(NSPCON-1) 500,425,500
  425  WRITE(IRITE,426)UOVALL,AREAC,SPFLOW
  426  FORMAT(5X,*CONDENSER SPECIFICATIONS*,/, 3X,*OVERALL U = *,F6.
     10,/, 3X,*TUBE AREA = *,E12.4,/,3X,*H2O FLOW = *,E12.4,//)
C
  500 CALL TRANS(NS,NTR,NT)
      RETURN
      END
```

```
      SUBROUTINE SITE(NS,NSEI,NTR,MNTR,NT,MNT,NCO,MNC,NSC,NCH,NP,IPF,ICF
     2)
C
C     SITE IS THE SUBROUTINE WHICH INPUTS ALL THE SITE RELATED DATA
C
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),IC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2O,TCBASE,  NTAMB,AMBOFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),   TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCCN,UOVALL,A
     XREAC,SPFLOW,   NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6 AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,IOO
      NAMELIST/CONFLG/ NS,NSEI,NTR,MNTR,NT,MNT,NCC,MNC,NSC,NCH,NP,IPF,
     2ICF,IOO
      NAMELIST/VARAMB/ TAMDB,TAMWB,TAMRV,AMWIND,AMRAD
      NAMELIST/INPUT/ TDB, TWB, WIND, DIR, RAD, PRPAGR, NTAMB, ACC,
     2CONSCT, MET, YOPCM, CCPM, TMLS, TMCST, ANFCR, GEO, DISTR, DISLC
      NAMELIST/WATRV/ QFLRIV, WIDTH, DEPTH, TAVH2O, NH2O, TDISMX, FISH,
     2 NR
    1 FORMAT(20A2)
    2 FORMAT(*0  SITE NUMBER *I3* IS *20A2/*  ITS LOCATION IS *20A2/)
    3 FORMAT(*4 THE VARIOUS AMBIENT CONDITIONS ARE */*0 UP TO (5) OPERAT
     2ING CONDITIONS CAN BE SUBMITTED BESIDES DESIGN VALUES*/*0 ZEROS IN
     3DICATE LESS THAN (5) VARIABLE CONDITIONS WERE INPUT*//,1H0,21X,1H1
     4,9X,1H2,9X,1H3,9X,1H4,9X,1H5,       5X*DESIGN*/*0 DRY BULB(F)*6F10
     5.1,/*0 WET BULB(F)*6F10.1,/*0 WIND(MPH)  *6F10.1,/*0 RADIATION  *6
     6F10.1,/*0 H2O TEMP(F)*6F10.1,/*0 LAND COST IS *F10.0* $/ACRE*///)
    4 FORMAT(*0  FOR THIS SITE, INPUT TRANSMISSION LINE INFORMATION IS *
     2/*0 NUMBER OF TRANSMISSION OPTIONS IS *I3//* OPTION NO.    NEW CO
     3NSTR DIST.     LOAD CTR. DIST. */,20X,* (MILES)*14X*(MILES)*/)
    5 FORMAT(*0              SITE INPUT INFORMATION*/)
  104 FORMAT(1H0,5X,I2,13X,F7.1,14X,F7.1)
  420 FORMAT(*0            RIVER INPUT PARAMETERS *//*   FLOW(CFS)    WIDT
     2H(FT)     DEPTH(FT)*/3F12.1//*    FISH VALUE AT PLANT IS *E9.2* DO
     3LLARS.*/*0 WATER TYPE = *I2,2X,*(0 = UNTRT. FRESH WATER, 1 = TRT F
     4RSH WATER, -1 = SALT H2O)*//)
      IREAD=5 $ IRITE=6
      READ(IREAD,CONFLG)
C     INPUT THE SITE NAME AND ITS LOCATION
      READ(IREAD,1) (NAMES(I),I=1,20)
      READ(IREAD,1)  (LOCI(I),I=1,20)
      WRITE(IRITE,2) NS,NAMES,LOCI
C     INPUT SITE INFORMATION WRT AIR AND LAND PARAMETERS
      READ(IREAD, INPUT)
C      INPUT WATER BODY PARAMETERS FOR THIS SITE.
      READ(IREAD,WATRV)
C     INPUT OPERATING CONDITIONS (ATMOSPHERIC AND WATER) UNDER WHICH THE
C     PLANT WILL PERFORM.
C     INITIALIZE ALL AMBIENT OPERATING COND ARRAYS TO 0.0
      DO 100 I=1,5
      TAMDB(I) = 0.0
      TAMWB(I) = 0.0
```

```
      TAMRV(I) = 0.0
      AMRAD(I) = 0.0
      AMWIND(I) = 0.0
  100 CONTINUE
      READ(IREAD,VARAMB)
C     WRITE OUT DESIGN PARAMETERS FOR COOLING SYSTEMS
      IF(IOO.EQ.3) PRINT 5
      IF(IOO.EQ.3) PRINT 3, TAMDB,TDB,TAMWB,TWB,AMWIND,WIND,AMRAD,RAD,
     2TAMRV,TAVH2O,PRPAGR
C     WRITE OUT TRANSMISSION DISTANCES
      IF(IOO.EQ.3) PRINT 4,MNTR
      IF(IOO.EQ.3) PRINT 104,(I,DISTR(I),DISLC(I),I=1,MNTR)
      IF(IOO.EQ.3) PRINT 420, QFLRIV, WIDTH, DEPTH, FISH, NH20
      RETURN
      END
```

```
      SUBROUTINE PAYOFF(NS,NTR,NT,NCO,NSC,NCH,NP,ICF)
      COMMON PSIZE,CCPKW,ANFCR,FUCST,NCAPS,CAP(6),TOTLD(5), COLPCT(5),TC
     XMIN(6),PCMIN(6),TCMAX(6),PCMAX(6),  HRCOF2(6),HRCOF1(6),HRCOF0(6),
     XTDB,TWB,RH,TAVH2C,TCBASE,  NTAMB,AMBDFC(5),AMBOPC(5),TAMDB(5),TAMW
     XB(5),AMBRH(5),  TAMRV(5),PCTAMB(5,5),NSYSOP,TDISMX,NSPCON,UOVALL,A
     XREAC,SPFLOW,  NH2O,WIDTH,PRPAGR,CAPFAC,USEFAC,TKWHRS,IRITE,IREAD,
     6  AMWIND(5),AMRAD(5),WIND,RAD,QFLRIV,DEPTH
      COMMON/NEWV/ CONCR,LOCI(20),ACC,CONSCT,DISLC(5),DISTR(5),    FLOW1
     2,YOPCM(5),CCPM(5),TMLS(5),TMCST(5),TRCST,WATER(4),DISCH(4),TDIS(4)
     3,CDIS(4),FISH,TZERO, NR,CSC,SSC,CFISH,CHSC,PNAME(4),NAMES(20),
     4SPGR, SPTR, SPCO, DELHR, CCSC, CCOST, CCOSTS, SPNC,ICO
      DIMENSION NAME(2),RNA(6),CNA(4),SNA(2),RTID(6),SOK(6,16),SSL(6,16)
     2,SLS(6,16), TCDIS(4)
C       DATA STATEMENTS
      DATA(NAME(I),I=1,2)/7HNUCLEAR, 7H FOSSIL/
      DATA(RNA(I),I=1,6)/8HCOLUMBIA,10HSACRAMENTO,10HUPPER MISS, 9HLOWER
     2MISS,9HTENNESSEE,8HDELAWARE/
      DATA(CNA(I),I=1,4)/5HRIVER,4HPOND,7HMECHTWR,7HNATDTWR/
      DATA(SNA(I),I=1,2)/8HDOES NOT,4HDOES/
      DATA(RTID(I),I=1,6)/6*10.0/
      DATA(SOK(I),I=1,96)/100.,100.,100.,100.,100.,100.,90.,89.,100.,
     2100.,100.,100.,82.,78.,100.,100.,100.,100.,65.,64.,100.,100.,
     3100.,100.,55.,64.,100.,100.,99.,98.,53.,61.,100.,100.,99.,94.,
     441.,47.,87.,88.,84.,80.,26.,45.,46.,69.,66.,57.,12.,8.,26.,31.,
     521.,39.,10.,6.,12.,20.,14.,27.,8.,3.,10.,16.,10.,18.,8.,3.,4.,
     612.,9.,12.,0.,0.,0.,4.,3.,10.,18*0./
      DATA(SSL(I),I=1,96)/6*0.,10.,11.,4*0.,18.,22.,4*0.,35.,36.,4*0.,
     239.,25.,0.,0.,1.,2.,41.,28.,0.,0.,1.,6.,41.,28.,13.,12.,16.,20.,
     343.,19.,54.,31.,34.,43.,51.,53.,74.,69.,77.,61.,41.,55.,88.,80.,
     484.,73.,14.,39.,74.,84.,87.,70.,8.,33.,45.,55.,57.,41.,12.,8.,
     526.,28.,19.,27.,8.,6.,9.,20.,13.,24.,4.,3.,3.,11.,5.,16.,6*0./
      DATA(SLS(I),I=1,96)/24*0.,6.,11.,4*0.,6.,11.,4*0.,18.,25.,4*0.,
     231.,36.,4*0.,37.,39.,2*0.,2.,0.,49.,39.,2*0.,2.,0.,78.,58.,16.,
     30.,3.,12.,84.,64.,51.,33.,34.,47.,88.,92.,74.,68.,78.,63.,92.,
     494.,91.,80.,87.,76.,96.,97.,97.,89.,95.,84.,6*100./
C
C      FORMAT STATEMENTS
C
    1 FORMAT(*1 BASELINE EVALUATION FOR *A7* FIRED THERMAL POWER PLANT A
     2T THIS SITE.*/)
    2 FORMAT(*1  THIS IS PAYOFF CALCULATION NUMBER *I2* FOR A *A7* POWER
     2 PLANT.*/*0 RIVER CLASS *A10/*0 THE PLANT UTILIZES *A10*COOLING*/
     3*0 IT *A8* HAVE A SCREENED INTAKE.*/*0 THE PLANT *A8* TREAT ITS CH
     4EMICAL DISCHARGE.*/*0 THE TRANSMISSION OPTION NO. IS *I2,/*0 -----
     5-----WATER USE INFORMATION----------*/)
    3 FORMAT(*0 THE PLANT WITHDRAWS *E9.2* CFS OF WATER FOR SUPPLY *//,*
     2  THE PLANT DISCHARGES *E9.2* CFS BACK FO THE RIVER.*/*0 NET WATER
     3 REMOVED BY THE PLANT IS *E9.2* CFS*/*0 (NOT COUNTING WATER EVAPOR
     4ATED AS A RESULT OF A THERMAL DISCHARGE.)*/)
    4 FORMAT(*0 DISCHARGE TEMPERATURE IS *F7.2* DEG-F*/*0 CHEMICAL CONCE
     2NTRATION IS *F4.0* TIMES THE INLET CONCENTRATION*/)
    5 FORMAT(*0 INFORMATION ABOUT THERMAL STATUS OF FISH SPECIES AT DISC
     2HARGE POINT*//1H0,40X,*PER CENT SPECIES IN*/*  CONDITION*11X*TEMP*
     34X*TEMP ZONE 1*5X*TEMP ZONE 2*5X*TEMP ZONE 3*/,1H ,21X,*DEG-C*/)
    6 FORMAT(*0 PROBLEMS W/O PLANT *F5.1,4X,F5.0,10X,F5.0,10X,F5.0,/)
```

```
   7 FORMAT(*0 NO SPECIES IN DANGER WITHOUT THERMAL PLANT.*)
   8 FORMAT(*0 PROBLEMS W/ PLANT  *F5.1,4X,F5.0,10X,F5.0,10X,F5.0,/)
   9 FORMAT(*0 NO SPECIES IN DANGER WITH THERMAL PLANT OPERATING.*/)
  10 FORMAT(*1 COST CALCULATIONS FOR THIS SET OF ALTERNATIVES.*)
  11 FORMAT(*0 BASE PLANT COST IS *F5.0* MILLION DOLLARS */*  PLANT CST
    2 AT THIS SITE IS *F5.0* MILLION DOLLARS. */)
  12 FORMAT(*0 COOLING SYSTEM COSTS ARE *10X,E9.2,5X,E9.2)
  13 FORMAT(*0 INTAKE SYSTEM COST IS *13X,E9.2,5X,E9.2/*  FISH DAMAGES
    2FROM SCREENS ARE *5X,E9.2,5X,E9.2)
  14 FORMAT(*0 CHEMICAL TREATMENT SYSTEM COSTS ARE*E9.2,5X,E9.2)
  15 FORMAT(*0 TOTAL TRANSMISSION COSTS ARE *6X,E9.2,5X,E9.2/)
  16 FORMAT(1H0,3X*TOTAL LAND UTILIZED FOR GENERATION, COOLING AND TRAN
    2SMISSION(ACRES)*/,1H ,3X* PLANT LAND *10X*COOLING LAND*10X*TRANSMI
    3SSION RT OF WAY*/,1H ,44X* TO LD CENTER     NEW CONST.*/)
  17 FORMAT(1H0,4X,F7.0,15X,F7.0,12X,F7.0,5X,F7.0//* TOTAL LAND USED IS
    2 *F7.0* ACRES.*/)
  18 FORMAT(*0   TOTAL COST OF POWER AT THIS SITE IS *E9.2* MILLS/KW-HR
    2.*////)
  19 FORMAT(*0 BASELINE AIR POLLUTANTS EMITTED BY THE NUCLEAR PLANT ARE
    2*/*  0.238 MICROCURIES OF LONGLIFED ISOTOPES PER KW/HR.*/)
  20 FORMAT(*0 BASELINE AIR POLLUTANTS EMITTED BY THE COAL FIRED PLANT
    2ARE EXPRESSED IN TERMS */*  OF LB OF QUANTITY X EMITTED PER KW-HR
    3OF ELECTRICITY GENERATED.*//*  MATERIAL       QUANTITY*///  * NO2
    4*10X*6.0E-04*//* SO2 *10X*5.7E-03*//* CO *11X*1.5E-05*//* HYDROCAR
    5BONS  6.0E-06*//* ALDEHYDES      1.5E-07*//* PARTICULATES  5.9E-03*
    6/)
  21 FORMAT(*0 AIR EMISSIONS FOR COAL FIRED UNIT  CHANGES RESULTING FRO
    2M NON-ONCE-THRU COOLING*//*  MATERIAL        QUANTITY(LB/KW-HR)*5X*
    3QUANTITY(LB/HR AT 100 PER CENT POWER)*///* NO2 *10X,E9.1,5X,E9.1/*
    4 SO2 * *10X,E9.1,5X,E9.1/* HYDROCARBONS  *E9.1,5X,E9.1/* ALDEHYDES
    5      *E9.1,5X,E9.1/* PARTICULATES  *E9.1,5X,E9.1/)
  22 FORMAT(*0   DATA IS INSUFFICIENT AT THIS TIME TO CALCULATE EXTRA N
    2UCLEAR*/*0   PLANT EMISSIONS CAUSED BY NON-ONCE-THRU COOLING.*/)
  23 FORMAT(1H0,20X,* DEFINITION OF THERMAL ZONES*/,1H0,5X,*ZONE 1 = PR
    2EFFERRED  TEMPERATURE RANGE*/,1H0,5X*ZONE 2 = SUBOPTIMAL TEMPERATU
    3RE CONDITION*/,1H0,5X,*ZONE 3 = TEMPERATURE ZONE WHERE SPECIES*/,1
    4H ,14X,*IS EXPECTED TO BE LOST FROM SYSTEM*/)
  24 FORMAT(*1 THIS IS AN INDIVIDUAL PAYOFF CALCULATION FOR A *A7* POWE
    2R PLANT.*/*0 RIVER CLASS IS *A10/*0 PLANT UTILIZES *A7* COOLING*/*
    30 IT *A8* HAVE SCREENED INTAKES.*/*0 THE PLANT *A8* TREAT ITS CHEM
    4ICAL DISCHARGE.*/*0 THE TRANSMISSION OPTION NO. IS *I2/*0---------
    5-WATER USE INFORMATION----------*/)
 111 FORMAT(*0  VARIOUS COMPONENT COSTS FOR THIS PLANT ARE *//31X*MILLS
    2 PER KW-HR   CAP COSTS($)*)
 112 FORMAT(*0 BASIC PLANT COST      *14X,E9.2,5X,E9.2)
 113 FORMAT(*0 BASIC PLANT FUEL COST *13X,E9.2)
C
C     PRINT OUT ALTERNATIVE COMBINATION NAME
C
      IF(ICF.EQ.1) PRINT 24,NAME(NT),RNA(NR),CNA(NCO),SNA(NSC),SNA(NCH),
     2NTR
      IF(ICF.EQ.0) PRINT 2, NP,NAME(NT),RNA(NR),CNA(NCO),SNA(NSC),SNA(NC
     2H),NTR
      IF(NCO.EQ.1.AND.NSC.EQ.1.AND.NCH.EQ.1) PRINT 1, NAME(NT)
C     PRINT OUT WATER INTAKE AND DISCHARGE TO RESIDENT WATER BODY
      UNET = WATER(NCO) - DISCH(NCO)
```

```
      PRINT 3, WATER(NCO), DISCH(NCO), UNET
C     PRINT OUT WATER QUALITY OF DISCHARGE WITH RESPECT TO TEMPERATURE
C     AND CHEMICAL CONTENT
      IF(NCH.EQ.1) TCDIS(NCO)=CDIS(NCO)
      IF(NCH.EQ.2) TCDIS(NCO)=0.0
      PRINT 4, TDIS(NCO), TCDIS(NCO)
C
C     DETERMINE POSSIBLE FISH DAMAGE FROM HEATED CONDENSER DISCHARGE
C     BASED ON MIXED RIVER TEMPERATURE AT POINT OF DISCHARGE
      PRINT 5
      TAVH2C = 5*(TAVH20 - 32.)/9.
      TZEROC = 5*(TZERO - 32.)/9.
      IWP = (TZEROC - 9.5)/2.
      INP = (TAVH2C - 9.5)/2.
      IF(INP.GT.0) PRINT 6, TAVH2C, SOK(NR,INP), SSL(NR,INP),SLS(NR,INP)
      IF(TAVH2C.LT.10.0) PRINT 7
      IF(NCO.EQ.1.AND.TZEROC.GE.10.0)PRINT 8, TZEROC, SOK(NR,IWP),SSL(NR
     2,IWP), SLS(NR,IWP)
      IF(NCO.EQ.1.AND.TZEROC.LT.10.) PRINT 9
      PRINT 23
C
C     CALCULATE AIR EMISSIONS FOR THIS ALTERNATIVE
C
      IF(NCO.EQ.1.AND.NT.EQ.1) PRINT 19
      IF(NCO.EQ.1.AND.NT.EQ.2) PRINT 20
      IF(NCO.NE.1.AND.NT.EQ.1) PRINT 22
C     CALCULATE EXTRA AIR EMISSIONS CAUSED BY CHANGE IN HEATRATE DUE
C     TO USE OF A NON-ONCE-THRU COOLING SYSTEM
      XFUEL = (DELHR/2.4)*1.E-7
      NO2 = XFUEL*6.0E-4
      NO2H = 1000.*PSIZE*NO2
      SO2 = XFUEL*5.7E-5
      SO2H = 1000.*PSIZE*SO2
      CO  = XFUEL*1.5E-5
      COH  = 1000.*PSIZE*CO
      HYD = XFUEL*6.0E-6
      HYDH = 1000.*PSIZE*HYD
      ALD = XFUEL*1.5E-7
      ALDH = 1000.*PSIZE*ALD
      PAR = XFUEL*5.9E-3
      PARH = 1000.*PSIZE*PAR
      IF(NCO.NE.1.AND.NT.EQ.2) PRINT 21, NO2,NO2H,SO2,SO2H,CO,COH,HYD,HY
     2DH,ALD,ALDH,PAR,PARH
      CALL SLOWST(NS,NT,NCO,NSC,NCH,NP)
C
C     PRINT OUT DOLLAR COSTS FOR THIS ALTERNATIVE
C     COMPARE STANDARD PLANT CAPITAL COST WITH CAPITAL COST AT THIS
C     LOCATION.
      PRINT 10
      COAT = CCPKW*(1. + (ACC + CONSCT)/100.)
      C1 = CCPKW*PSIZE/1000.
      C2 = COAT*PSIZE/1000.
      C3 = C2*1000.*ANFCR/TKWHRS
      TC2 = C2*1.E6
      PRINT 11, C1, C2
C
```

```
C       COST OUT COOLING ALTERNATIVE
C
        PRINT 111
        PRINT 112, C3, TC2
        IF(NT.EQ.1) HRBASE = 9815.
        IF(NT.EQ.2) HRBASE = 7220.
        CFU = HRBASE*FUCST*1.E-5
        PRINT 113, CFU
        PRINT 12, CSC, CCSC
C
C       COST OUT SCREENING ALTERNATIVE
C
        D = PSIZE*1000.*CAPFAC*8.76
        CCF = CFISH*D
        PRINT 13, SSC, CCOSTS, CFISH, CCF
C
C       ESTIMATE CHEMICAL TREATMENT COSTS
C
        CCT = CHSC*D
        PRINT 14, CHSC, CCT
C
C       TRANSMISSION COSTS FOR THE SITE ARE
C
        PRINT 15, TRCST, CCOST
C
C       ADD UP COMPONENT COSTS TO GET THE COSTS OF THE POWER DELIVERED TC
C       THE GRID SYSTEM AND THE LOAD CENTER.
C
        TC = TRCST  + CHSC + SCC + CFISH + CSC + C3 + CFU
        PRINT 18, TC
C       DETERMINE TOTAL LAND CONSUMED BY THE PLANT, COOLING MEANS, AND
C       TRANSMISSION LINES.
        PRINT 16
        SPT = SPGR + SPTR + SPCO
        PRINT 17, SPGR, SPCO, SPTR, SPNC, SPT
        RETURN
        END
```

POWER PLANT SITING ANALYSIS PROGRAM

SITE NUMBER 1 IS SAMPLE DATA INPUT CASE FOR SITING PROG.
ITS LOCATION IS PLANT ON RIVER CLASS NO 1

-----NOTE POWER PLANT DATA SPECIFIED IS INTERNAL DATA
NO POWER PLANT DATA WERE INPUT.

RESULTS OF TRANSMISSION COST CALCULATIONS FOR SITE NUMBER 1
WITH PLANT TYPE 1

	CAPITAL COSTS (DOLLARS)	COST PER UNIT POWER (MILLS/KW-HR)
TRANSMISSION OPTION IS 1		
NEW TRANSMISSION LINES		
CONSTRUCTION COST	4.50E+06	5.92E-02
MAINTENANCE COST	4.88E+03	6.42E-04
NEW TRANS TOTAL COST		5.99E-02
LOAD CENTER RELATED COSTS		
WHEELING COST(BPA)		2.64E-01

TOTAL TRANSMISSION COSTS AT THIS SITE ARE 3.24E-01 MILLS/KW-HR.

```
----- MECHANICAL DRAFT WET TOWER -----

THE DESIGN VALUES AND COSTS ARE -


Q REJECT =  6.4514E+09 BTU/HR  AT T CONDENSER =  101
FAN POWER =  5.7984E+03HP  PUMP POWER =  1.3436E+04HP
    H2O EVAP =  2.9446E+01 CFS (  6.6165E+06LB/HR)
H2O BLOWDOWN =  7.1854E+00 CFS (  1.6146E+06 LB/HR)
AIR FLOW RATE =  3.3621E+08 LB/HR
PRESSURE DROP =  .37    COND FLOW =  5.3602E+08
RANGE =  12     APPROACH =  11

CAPITAL COST =  6.8169E+06 DOLLARS
CONDENSER AND PUMPCOST =  1.0569E+01 DOLLARS/KW
OPERATING COST =  .076 MILLS/KW-HR
MAINTENANCE COST =  .016 MILLS/KW-HR
CONDENSER SYSTEM COST =  .186 MILLS/KW-HR
DIFFERENTIAL FUEL COST =  .010 MILLS/KW-HR

  TOTAL SYSTEM COST =  .377 MILLS/KW-HR


          VARIABLE AMBIENT CONDITIONS


     FOR CAP = .80,     T WB =   20,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .80,     T WB =   45,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .80,     T WB =   33,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .60,     T WB =   20,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .60,     T WB =   45,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .60,     T WB =   33,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .25,     T WB =   75,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .25,     T WB =   20,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .25,     T WB =   45,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

     FOR CAP = .25,     T WB =   33,  AND            TC =  92
PC LESS THAN PC MIN - ASSUME PC MIN - CONTINUE

  WITH THE VARIOUS AMBIENT TEMPERATURES
  THE COSTS ARE -

OPERATING COST =  .083 MILLS/KW-HR
```

```
DIFFERENTIAL FUEL COST = -.004 MILLS/KW-HR

TOTAL SYSTEM COST =  .371 MILLS/KW-HR

   SCREENING CALCULATIONS FOR NATDFT TWR   COOLING
  THE FLOW TO BE CONSIDERED FOR SCREENING IS  4.14E+01 CFS.

    THE SCREENING COSTS ARE

 CAPITAL COSTS  5.45E-04MILLS/KWHR
 OPERATING COSTS 5.45E-05MILLS/KWHR
TOTAL COSTS ARE 6.00E-04  MILLS/KWHR


 INTAKE COSTS WITHOUT SCREENING

CAPITAL COST 3.27E-04 MILLS/KWHR
OPERATING COSTS  3.27E-05MILLS/KWHR

TOTAL SYSTEM COST IS 3.60E-04 MILLS/KWHR


 THE SCREENING DAMAGE TO FISH HAS A VALUE OF  2.18E-04 MILLS/KW-HR
 COMPARED TO SCREENING COSTS OF  6.00E-04 MILLS/KW-HR

DISCH(NCO) = 7.185436   FL = 4.635765   TC = 8.210690
CHSC = .0158595
```

THIS IS AN INDIVIDUAL PAYOFF CALCULATION FOR A NUCLEAR POWER PLANT.

RIVER CLASS IS COLUMBIA

PLANT UTILIZES MECHTWR COOLING

IT DOES HAVE SCREENED INTAKES.

THE PLANT DOES TREAT ITS CHEMICAL DISCHARGE.

THE TRANSMISSION OPTION NO. IS 1

----------WATER USE INFORMATION----------

THE PLANT WITHDRAWS 4.14E+01 CFS OF WATER FOR SUPPLY

THE PLANT DISCHARGES 7.19E+00 CFS BACK TO THE RIVER.

NET WATER REMOVED BY THE PLANT IS 3.42E+01 CFS

(NOT COUNTING WATER EVAPORATED AS A RESULT OF A THERMAL DISCHARGE.)

DISCHARGE TEMPERATURE IS 90.39 DEG-F

CHEMICAL CONCENTRATION IS 0 TIMES THE INLET CONCENTRATION

INFORMATION ABOUT THERMAL STATUS OF FISH SPECIES AT DISCHARGE POINT

CONDITION	TEMP DEG-C	PER CENT SPECIES IN TEMP ZONE 1	TEMP ZONE 2	TEMP ZONE 3
PROBLEMS W/O PLANT	18.9	65	35	0

DEFINITION OF THERMAL ZONES

ZONE 1 = PREFFERRED TEMPERATURE RANGE

ZONE 2 = SUBOPTIMAL TEMPERATURE CONDITION

ZONE 3 = TEMPERATURE ZONE WHERE SPECIES
IS EXPECTED TO BE LOST FROM SYSTEM

DATA IS INSUFFICIENT AT THIS TIME TO CALCULATE EXTRA NUCLEAR

PLANT EMISSIONS CAUSED BY NON-ONCE-THRU COOLING.

THE NUCLEAR FUEL SYSTEM IS A CLOSED LOOP.
NO FUEL SOLID WASTE IS HANDLED AS A SEPARATE, EXTERNAL PROBLEM.
ALL FUELCOSTS(INCLUDING SOLID WASTE ARE INTERNALIZED IN FUEL PRICE)

COST CALCULATIONS FOR THIS SET OF ALTERNATIVES.

BASE PLANT COST IS 250 MILLION DOLLARS
PLANT CST AT THIS SITE IS 267 MILLION DOLLARS.

VARIOUS COMPONENT COSTS FOR THIS PLANT ARE

	MILLS PER KW-HR	CAP COSTS($)
BASIC PLANT COST	3.52E+00	2.67E+08
BASIC PLANT FUEL COST	1.96E+00	
COOLING SYSTEM COSTS ARE	3.77E-01	6.82E+06
INTAKE SYSTEM COST IS	6.00E-04	4.14E+04
FISH DAMAGES FROM SCREENS ARE	0.	0.
CHEMICAL TREATMENT SYSTEM COSTS ARE	1.59E-02	1.20E+05
TOTAL TRANSMISSION COSTS ARE	3.24E-01	4.50E+06

TOTAL COST OF POWER AT THIS SITE IS 6.20E+00 MILLS/KW-HR.

TOTAL LAND UTILIZED FOR GENERATION, COOLING AND TRANSMISSION(ACRES)

PLANT LAND	COOLING LAND	TRANSMISSION RT OF WAY TO LD CENTER	NEW CONST.
500	20	3182	318

TOTAL LAND USED IS 3702 ACRES.

THIS IS AN INDIVIDUAL PAYOFF CALCULATION FOR A NUCLEAR POWER PLANT.

RIVER CLASS IS COLUMBIA

PLANT UTILIZES POND COOLING

IT DOES HAVE SCREENED INTAKES.

THE PLANT DOES NOT TREAT ITS CHEMICAL DISCHARGE.

THE TRANSMISSION OPTION NO. IS 1

-----------WATER USE INFORMATION----------

THE PLANT WITHDRAWS 7.45E+01 CFS OF WATER FOR SUPPLY

THE PLANT DISCHARGES 0. CFS BACK FO THE RIVER.

NET WATER REMOVED BY THE PLANT IS 7.45E+01 CFS

(NOT COUNTING WATER EVAPORATED AS A RESULT OF A THERMAL DISCHARGE.)

DISCHARGE TEMPERATURE IS 0.00 DEG-F

CHEMICAL CONCENTRATION IS 0 TIMES THE INLET CONCENTRATION

INFORMATION ABOUT THERMAL STATUS OF FISH SPECIES AT DISCHARGE POINT

		PER CENT SPECIES IN		
CONDITION	TEMP DEG-C	TEMP ZONE 1	TEMP ZONE 2	TEMP ZONE 3
PROBLEMS W/O PLANT	18.9	65	35	0

DEFINITION OF THERMAL ZONES

ZONE 1 = PREFFERRED TEMPERATURE RANGE

ZONE 2 = SUBOPTIMAL TEMPERATURE CONDITION

ZONE 3 = TEMPERATURE ZONE WHERE SPECIES
IS EXPECTED TO BE LOST FROM SYSTEM

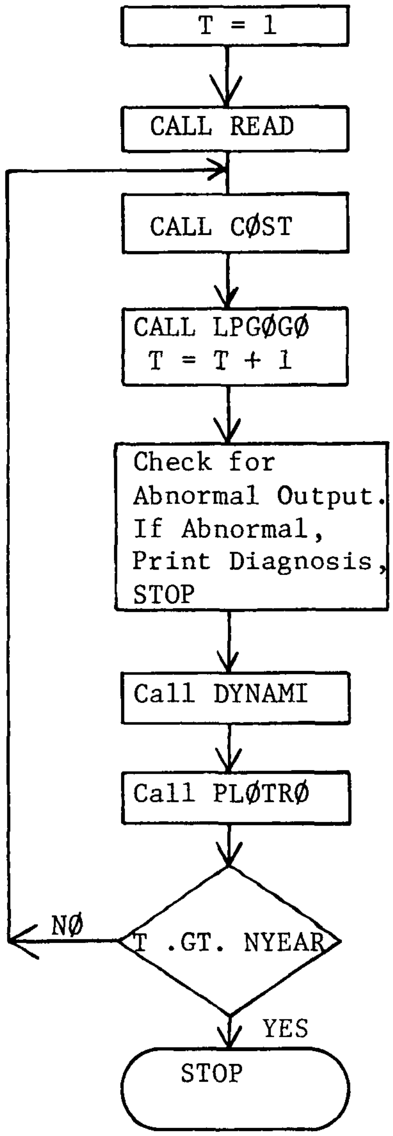
DATA IS INSUFFICIENT AT THIS TIME TO CALCULATE EXTRA NUCLEAR PLANT
.EMISSIONS CAUSED BY NON-ONCE -THRU COOLING.

THE NUCLEAR FUEL SYSTEM IS A CLOSED LOOP.
NO FUEL SOLID WASTE IS HANDLED AS A SEPARATE, EXTERNAL PROBLEM.
ALL FUELCOSTS(INCLUDING SOLID WASTE ARE INTERNALIZED IN FUEL PRICE)

Appendix C. Dynamic Model Description

Program MAIN

MAIN is the executive routine. It calls the analysis subprograms in the proper order. A flow chart for MAIN is shown below.



Subroutine READ

This subroutine reads all input variables and performs partial initializing for future processing. Format for the input data is given below. The input data cards are discussed in the order of their appearance in the input file. A sample data set for the sample output is supplied immediately following the deck listing.

Card 1: Title A72 A72

Card 2: M, N, NSTA, NYEAR, NTYPE, ICHECK 6I5

Note: ICHECK = 1 gives complete output

= 2 gives abbreviated output

Card 3: CØSTPØ (I,J) 4F10.4

I = 1 to No. of Regions (7 maximum)

J = 1 to No. of Types of Power Generation within each region (4 maximum)

Each card is for a region.

As many cards are needed as there are regions.

Next I Cards:

I + 4: TR (I, J) 7F10.4

Transmission cost from region I to J.

One card per region.

Next I Cards:

PEX(I) Power expansion Unit (MWe) 8F10.4

Next I Cards:

PRES(J) 7F10.4

Reserve power required in region I (MWe)

Next I Cards:

PSDM(I,J) 4F10.4

One card per each region I, gives

PSDM(I,J), J = 1, NTYPE. Zeros acceptable

Next Card: PSDIN(I) 7F10.4

Next Card: PØP(I,1) 7F10.4

Initial population for the I regions (10^6 people)

Next Card: PØPMAX(I) 7F10.4

Maximum population for region I (10^6 people)

Next Card: GRØW(I) 7F10.4

Growth rate in region I (%/yr)

Next Card: PWD(I,1) 7F10.4

Initial power demand in region I = 1, No. of regions (MWe)

The above input is followed by a lengthy input section for the linear programming optimization routine. For the above input reference can be made to the following list of variables and comment cards in the program for added helpful information. The linear optimization routine is slightly modified from Daellenbach and Bell (1970). A complete explanation of the routine and input is found therein. The following discussion applies to the input in the sample case:

14 Cards: PWD1 A6

⋮

PWD7

PSD1

⋮

PSD7

Identifying constraint equation names.
Two cards for each region. Constraints are supply and demand satisfaction. Names begin in column 1 and must be no longer than 6 characters.

The next n cards are variable cards. Each decision and slack variable must be identified. In this case power interties between each region are identified. Names begin in column 9 and must end by column 14. The following short example is shown for region 1 to all others. 56 cards

P11	
P12	
P13	others begin with
P14	P21, P31, P41,. . .
P15	
P16	
P17	

must input identifying all such interchanges PIJ (49) plus 7 slack variables (SLACK 1....SLACK 7).

Input next are the cards giving the left hand side coefficient of the variables in each constraint relation. For 7 regions there are 7 sets of 7 cards each. Again one set is shown with n sets being necessary for n regions. Columns are indicated above the significant letters.

1	9	28
PWD1	P11	1.00
PWD1	P21	1.00
PWD1	P31	1.00
PWD1	P41	1.00
PWD1	P51	1.00
PWD1	P61	1.00
PWD1	P71	1.00

Input Format is A6, 2X, A6, 2X, F12.6. After all similar variables above are entered. The supply constraints are input to construct the supply relations. The same format is used as shown above. The sample data cases are not precisely right adjusted because blanks count as zeros. Care should be exercised in use of such methods, however.

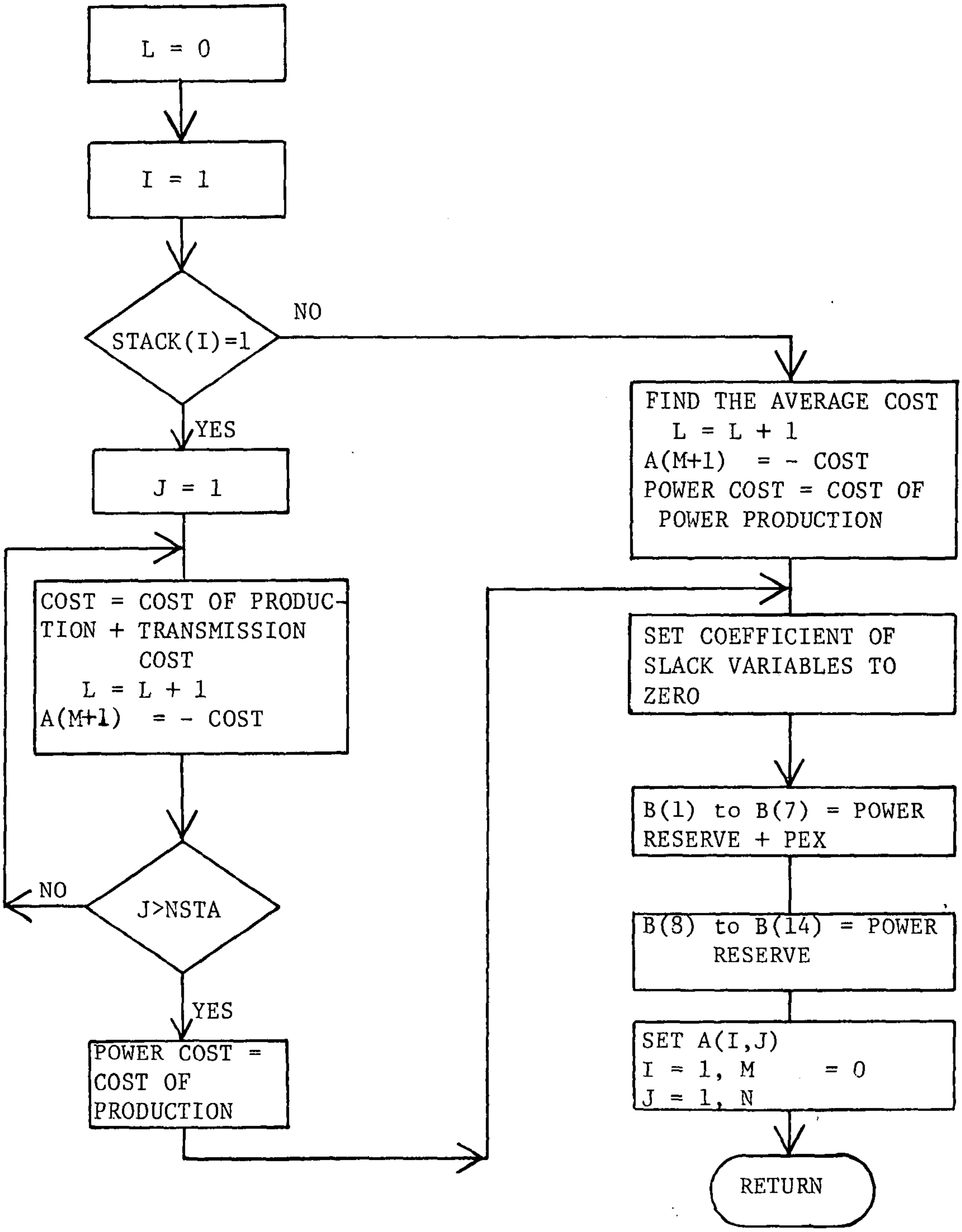
PSD1	P12	-1.00	
PSD1	P13	-1.00	
PSD1	P14	-1.00	
PSD1	P15	-1.00	
PSD1	P16	-1.00	Sample for
PSD1	P17	-1.00	Region = 1
PSD1	P21	1.00	
PSD1	P31	1.00	
PSD1	P41	1.00	
PSD1	P51	1.00	
PSD1	P61	1.00	
PSD1	P71	1.00	
PSD1	SLACK1	1.00	

Such a data set is input for each region. The Last card input is SØLVE beginning in col. 1.

Subroutine CØST

The routine determines the cost of power production in each region. Since the objective is cost minimization, all costs are multiplied by a -1 for processing by the linear program and stored in ARRAY (M + 1, L). M is the number of constraints, L is the number of variables.

If power production in any region is done by methods other than hydro power, new units are added in increments of 1 MW. The cost of production is an average value over all costs within the region. The flow chart for CØST appears on the next page. Variable B generates the right hand side coefficients for the constraint relations. Coefficients are generated for power demands and power reserves for each region.



Flow Chart for Subroutine CØST

Subroutine LPGØGØ

The routine is a modified linear optimization routine from Daellenbach and Bell (1970). It is calculationally unmodified. A performance check variable has been installed to check for improper functioning.

INØFES = 1, Normal Execution
INØFES = 2, No Feasible Solution
" = 3, Inconsistent Names in Input
= 4, Unbounded Solution

Output from LPGØGØ is stored in arrays IRØW1 and X1.

Subroutine DYNAMI

This routine takes results from LPGØGØ and calculates future demand, future supply and future power cost for each region. Program flow is explained by the detailed comment cards included in the listing.

Subroutine PLØTRØ

This routine outputs results by region on a line printer. The routine utilizes UMPLØT for the CDC-6400. Call statements should be checked for compatibility with local routines. Seven plots are generated for each region.

1. Power Demand v. Year
2. Power Produced v. Year
3. Power Price v. Year
4. Population v. year

Sample outputs show results for sample data so that program functioning can be checked.

LIST OF VARIABLES

VARIABLE	DEFINITION
CØSTPØ	Cost of power production (mills/kW-hr)
ELAS	Price elasticity of demand
GRØW	Population growth rate (%/yr)
ICHECK	Variable used to suppress output
INØFES	Output check variable
LØSS	Power loss in transmission (%)
M	Number of constraints
N	Number of variables
NSTA	Number of regions with power generating capacity
NTYPE	Number of types of power generation within a region
NYEAR	Number of years in analysis
PADD	Power added each year (MWe)
PCØS	Cost of power production
PØP	Population (millions of people)
PØPMAX	Maximum population (millions)
PØWEXI	Existing power production capacity (MWe)
PRES	Power reserve required (MWe)
PDS	Power supplied (MWe)
PSDIN	Sum of maximum power production capacity (MWe)
PSDM	Power supplied by each method (MWe)
PSØLD	Selling price of power (mills/kW-hr)
PWD	Power Demand
T	Time (years)
TR	Transmission cost region to region (mills/kW-hr)
VAL	Value

```
      PROGRAM MAIN(INPUT,OUTPUT,TAPE5=INPUT,TAPE6=OUTPUT)
      DIMENSION COSTPO(10,5),P(10,10),NEWP(10), POWEXI(10),
     1B(52),JCOL(100),IROW(50),IBASIS(50),ITITLE(12),PEX(50),
     1PWD(7,50),PSD(7,50),PSDM(10,5),PCOS(10,50),ELAS(10),PPC(10),
     1IROW1(100),X1(100),PRES(10),PSDIN(10),POP(10,50),POPMAX(10),
     1GROW(10),A(52,150),PPC1(10),STACK(10),POPX(10,50),TR(10,10),
     1DPOP(10),PADD(10),IDUP(150),JDUP(150),VALDUP(150),PSOLD(10,50),
     1CON(10),GROCON(10)
      COMMON T,A,B,JCOL,IROW,IBASIS,ITITLE,M,N,NSTA,PEX,PWD,PSD,
     1P,NEWP,POWEXI,PCOS,ELAS,PPC,PPC1,STACK,LOSS,VAL,POPX,NTYPE,
     1IROW1,X1,MPLUS2,NM,NYEAR,PRES,PSDIN,POPMAX,POP,GROW,TR,PADD,
     1COSTPO,PSDM,IDUP,JDUP,VALDUP,INOFES,ICHECK,PSOLD,CON,GROCON
C      1  NAME OF PROBLEM IN COL.   1 TO 12
C         2     NO OF CONSTRAINTS,NO OF VARIABLES INCLUDING SLACK VARIABLE
C               NO OF GENERATING STATIONS,NO OF YEAR,NO OF TYPES OF
C               POWER PRODUCTION AND ICHECK
C               ALL SIX INPUTS IN ONE CARD    FORMAT 6I5  DATA RIGHT ADJUS
C         ICHECK = 2 WILL SUPRESS MOST OF THE INTIAL PRINTOUTS
C      3  COSTPO(I,J)     COST OF PRODUCTION OF POWER BY VARIOUS METHODS
C         IN EACH STATION        I  =  STA,    J =  METHOD
C         FORMAT    4F10.4
C         DATA 4 PER CARD  STATION BY STATUON
C      4  TR(I,J)     TRANSMISSION COST FROM STATION I TO STATION J
C         FORMAT    7F10.4
C         7 DATA PER CARD  STATION I TO ALL THE OTHER STAIONS
C      5  PEX(I)
C         FORAMT    8F10.4
C      6  PRES(J)    POWER RESERVE
C         FORMAT(7F10.4)
C      7  PSDM(I,J)   MAXIMUM POWER THAT CAN BE PRODUCED BY EACH METHOD
C         FORMAT  4F10.4
C         NO OF CARDS    NO OF STATIONS
C         IF NO POWER IS PROUCED BY ANY METHOD LEAVE THAT COL. BLANK OR R
C         ZERO
C      8  PSDIN(J)  SUM OF POWER PRODUCED BY ALL THE METHODS IN A STATION
C         FORMAT(7F10.4)
C      9  POP(J,1)  POPULATION IN EACH REGION  * (10**6) FOR THE BASE YEA
C         FORMAT    7F10.4
C      10 POPMAX(J)  MAXIMUM POPULATION IN EACH REGION* (10**6)
C         FORMAT (7F10.4)
C      11 GROW(J)   GROWTH RATE OF POPULATION FOR ALL THE REGION  IN PERC
C         FORMAT  7F10.4
C      12 PWD(J,1)  POWER DEMAND FOR THE FIRST YEAR FOR ALL REGIONS
C         FORMAT   7F10.4
C      13 INPUT  FOR  LPGOGO EXPLAINED IN SUBROUTINE  LPGOGO
C         *********************
      INTEGER T,STACK
      REAL NEWP,LOSS
      INOFES = 1
       T = 1
C       SUBROUTINE READ   READS IN ALL THE INPUT VARIABLES ACCORDING TO
C       CIFICATION GIVEN IN COMMENTS  1  TO  12
      CALL READ
C       SUBROUTINE  COST  DETERMINES THE AVERAGE COST OF POWER PRODUCTI
   20 CALL COST
```

```
C         SUBROUTINE  LPGOGO FINDS THE OPTIMAL SOLUTON
           CALL LPGOGO
          GO TO (1,2,3,4),INOFES
C         SUBROUTINE DYNAMI CALCULATES POWER DEMAND,POWER SUPPLIED,POPULA
C         ETC   FROM THE OPTIMAL SOLUTIONS OBTAINED FROM LPGOGO
    1     CALL DYNAMI
          IF(T .GT. NYEAR) GO TO 15
          GO TO 20
C         SUBROUTINE PLOTRO  PLOTS THE OUTPUT ON LINE PRINTER
   15     CALL PLOTRO
          GO TO 10
C         THE FOLLOWING 3 WRITE STATEMENTS PRINTS THE DIAGONOSIS FROM LPG
    2     WRITE(6,31)T
          GO TO 10
    3     WRITE(6,32)
          GO TO 10
    4     WRITE(6,33)
   10      STOP
   31     FORMAT(10X,*NO FEASIBLE SOLUTION FOR TH  YAER *,I5)
   32     FORMAT(10X,*IN CONSISTANT NAMES IN THE INPUT  UNABLE TO
         1 FORM CONSTRAINT EQUATIONS CHECK INPUT*,/)
   33     FORMAT(10X,*SOLUTION UNBOUNDED  CHECK THE CONSTAINTS AND
         1 AND THE OBJECTIVE FUNCTIONS*,/)
          END
```

```
      SUBROUTINE READ
      DIMENSION COSTPO(10,5),P(10,10),NEWP(10), POWEXI(10),
     1B(52),JCOL(100),IROW(50),IBASIS(50),ITITLE(12),PEX(50),
     1PWD(7,50),PSD(7,50),PSDM(10,5),PCOS(10,50),ELAS(10),PPC(10),
     1IROW1(100),X1(100),PRES(10),PSDIN(10),POP(10,50),POPMAX(10),
     1GROW(10),A(52,150),PPC1(10),STACK(10),POPX(10,50),TR(10,10),
     1DPOP(10),PADD(10),IDUP(150),JDUP(150),VALDUP(150),PSOLD(10,50),
     1CON(10),GROCON(10)
      COMMON T,A,B,JCOL,IROW,IBASIS,ITITLE,M,N,NSTA,PEX,PWD,PSD,
     1P,NEWP,POWEXI,PCOS,ELAS,PPC,PPC1,STACK,LOSS,VAL,POPX,NTYPE,
     1IROW1,X1,MPLUS2,NM,NYEAR,PRES,PSDIN,POPMAX,POP,GROW,TR,PADD,
     1COSTPO,PSDM,IDJP,JDUP,VALDUP,INOFES,ICHECK,PSOLD,CON,GROCON
       INTEGER T,STACK
       REAL NEWP,LOSS
    1 DO 4 K=1,12
      ITITLE(K) = 0
    4 CONTINUE
      READ(5,1001)(ITITLE(I),I=1,12)
      WRITE(6,1101)(ITITLE(I),I=1,12)
C        M     =   NO OF CONSTRAINTS
C        N    =   NO OF VARIABLES
C        NSTA  =  NO OF GENEARTING STGATIONS
C        ICHECK  =  2  WILL SUPRESS MOST OF THE OYTPUT
C        NTYPE   =  NO OF TYPES OF POWER PRODUCTIONS
C        ICHECK       VALUE = 1  OR 2
       READ(5,1002)M,N,NSTA,NYEAR,NTYPE,ICHECK
      MPLUS2 = M+2
      DO 5 I = 1,MPLUS2
      B(I) = 0.0
      DO 5 J = 1,NM
      A(I,J) = 0.0
    5 CONTINUE
      NM = N+M
       DO 240 I=1,NSTA
       STACK(I)=1
  240 CONTINUE
       GO TO (501,502),ICHECK
  501  WRITE(6,500)M,N,NYEAR,NSTA,NTYPE
C        READ IN COST OF PRODUCTION FOR VARIOUS METHODS
  502  READ(5,2001)((COSTPO(I,J),J=1,NTYPE),I=1,NSTA)
       GO TO (10,11),ICHECK
   10 WRITE(6,2010)
        WRITE(6,2020)
       DO 210 J=1,NSTA
       WRITE(6,2040)J,(COSTPO(J,I),I=1,NTYPE)
  210 CONTINUE
   11 READ(5,2050)((TR(I,J),J=1,NSTA),I=1,NSTA)
      GO TO (20,21),ICHECK
  20  WRITE(6,2051)
        WRITE(6,2052)
       I=1
 2054 WRITE(6,2055)I,(TR(I,J),J=1,NSTA)
       I=I+1
       IF(I.LE.NSTA) GO TO 2054
  21  READ(5,2060)(PEX(I),I=1,NYEAR)
```

```
      READ(5,2070)(PRES(J),J=1,NSTA)
     READ(5,2001)((PSDM(I,J),J=1,NTYPE),I=1,NSTA)
     GO TO (30,31),ICHECK
30   WRITE(6,220)
     DO 200 J=1,NSTA
     WRITE(6,2040)J,(PSDM(J,I),I=1,NTYPE)
200 CONTINUE
31   READ(5,2070)(PSDIN(J),J=1,NSTA)
       READ(5,2070) (POP(J,1),J=1,NSTA)
       READ(5,2070) (POPMAX(J),J=1,NSTA)
       READ(5,2070) (GROW(J),J=1,NSTA)
     READ(5,2070)(PWD(J,T),J=1,NSTA)
       DO 260 J =1,NSTA
       GROW(J) = GROW(J)/100.
      GROCON(J) = GROW(J)
260  CONTINUE
     DO 250 I=1,NSTA
     IF(PSDM(I,1) .EQ. 0.0) GO TO 251
     GO TO 250
251 STACK(I) = STACK(I) + 1
     MI = STACK(I)
     PADD(I)= 1.0
     IF(PSDM(I,MI) .EQ. 0.0) GO TO 251
250 CONTINUE
      DO 230 I=1,NSTA
     MI = STACK(I)
     POWEXI(I) = PSDM(I,MI)
     CON(I) = (PWD(I,1)/POP(I,1)) + 0.03
230 CONTINUE
    GO TO (510,511),ICHECK
510 WRITE(6,281)(PSDIN(J),J=1,NSTA)
    WRITE(6,282)(POP(J,1),J=1,NSTA)
    WRITE(6,283)(POPMAX(J),J=1,NSTA)
    WRITE(6,284)(GROW(J),J=1,NSTA)
     WRITE(6,280)(POWEXI(I),I=1,NSTA)
     WRITE(6,285)(CON(I),I=1,NSTA)
220 FORMAT(5X,7HSTATION,8X,6HMAXHYD,7X,11HMAXONCE THR,6X,
   112HMAX COOL TOW,7X,8HMAX DRY ,//)
280 FORMAT(5X,*EXISITING POWER*,7(5X,F10.4))
1001 FORMAT(12A6)
500  FORMAT(10X,*NO OF CONSTRAINTS        =  *,I5,/,10X,*NO OF VARIABLES
   1   =  *,I5,/,10X,*NO FO YEAR     = *,I5,/,10X,*NO OF GENERAING STAT
   1IONS  =  *,I5,/,10X,*NO OF TYPES OF POWER PRODUCTIONS   = *,I5,/)
1002  FORMAT(6I5)
2001 FORMAT(4F10.4)
2010     FORMAT(10X,*COST OF PRODUCTION  POWER BY VARIOUS METHODS*,///)
2040 FORMAT(5X,I5,4(5X,F12.4)///)
2050 FORMAT(7F10.4)
2020     FORMAT(5X,7HSTATION,8X,5HHYDRO,10X,8HONCE THR,12X,8HCOOL TOW,
   17X,5HDRY   ,///)
2051 FORMAT(1H1,10X* TRANSMISSION COST REGION I TO REGION J*///)
2052 FORMAT(14X,1H1,9X,1H2,9X,1H3,9X,1H4,9X,1H5,9X,1H6,12X,1H7//)
2055 FORMAT(2X,I2,7(2X,F10.4)//)
2060 FORMAT(8F10.4)
2070 FORMAT(7F10.4)
2080 FORMAT(8E10.4)
```

```
1101 FORMAT(1H1,12A6,///)
 281 FORMAT(1H1,5X,*PSDIN*,7(5X,F12.4))
 282 FORMAT(5X,*POP J,1*,7(5X,F12.4))
 283 FORMAT(5X,*POPMAX*,7(5X,F12.4))
 284 FORMAT(5X,*GROW*,7(5X,F12.4))
 285  FORMAT(5X,*CON   *,7(5X,F12.4))
 511  RETURN
      END
```

```
      SUBROUTINE COST
C     THIS SUBROUTINE FINDS THE COST C(I,J) = C(I)+TR(I,J)
C     C(I) IS THE COST TO PRODUCE POWER AT STATION I
C     TR(I,J) IS THE COST TO TRANSMIT POWER FROM STATION I TO J
      DIMENSION COSTPO(10,5),P(10,10),NEWP(10), POWEXI(10),
     1B(52),JCOL(100),IROW(50),IBASIS(50),ITITLE(12),PEX(50),
     1PWD(7,50),PSD(7,50),PSDM(10,5),PCOS(10,50),ELAS(10),PPC(10),
     1IROW1(100),X1(100),PRES(10),PSDIN(10),POP(10,50),POPMAX(10),
     1GROW(10),A(52,150),PPC1(10),STACK(10),POPX(10,50),TR(10,10),
     1UPOP(10),PADD(10),IDUP(150),JDUP(150),VALDUP(150),PSOLD(10,50),
     1CON(10),GROCON(10)
      COMMON T,A,B,JCOL,IROW,IBASIS,ITITLE,M,N,NSTA,PEX,PWD,PSD,
     1P,NEWP,POWEXI,PCOS,ELAS,PPC,PPC1,STACK,LOSS,VAL,POPX,NTYPE,
     1IROW1,X1,MPLUS2,NM,NYEAR,PRES,PSDIN,POPMAX,POP,GROW,TR,PADD,
     1COSTPO,PSDM,IDUP,JDUP,VALDUP,INOFES,ICHECK,PSOLD,CON,GROCON
      INTEGER T,STACK
      REAL NEWP,LOSS
      L=0
      DO 100 I = 1,NSTA
      MA = STACK(I)
      IF(MA .NE. 1) GO TO 81
      DO 170 J=1,NSTA
      COST = COSTPO(I,MA) + TR(I,J)
      L = L + 1
      A(M+1,L) = (-1.*COST)
  170 CONTINUE
      PCOS(I,T)=COSTPO(I,MA)
      GO TO 100
   81 COST2 =0.0
      COST1 = 0.0
      M1 = MA-1
      DO 160 LB = 1,M1
      COST1=COST1 + COSTPO(I,LB) * PSDM(I,LB)
      COST2 = COST2 + PSDM(I,LB)
  160 CONTINUE
      COST1 = COST1 + PADD(I) * COSTPO(I,MA)
      COST2=COST2 + PADD(I)
      COST3 = COST1/COST2
      DO 180 J=1,NSTA
      COST = COST3 + TR(I,J)
      L = L + 1
      A(M+1,L) = (-1.*COST)
  180 CONTINUE
      PCOS(I,T)=COST3
  100 CONTINUE
      NSLAK = N-L
      DO 30 I = 1,NSLAK
      L=L+1
      A(M+1,L) = 0.0
   30 CONTINUE
      DO 110 J=1,NSTA
  110 B(J)=PWD(J,T)+PEX(T)
C     NOTE     PRES   SIGN CHANGED
      DO 120 J=1,NSTA
  120 B(NSTA+J)= PRES(J)
```

```
      DO 50 I=1,M
      DO 50 J=1,N
      A(I,J) = 0.0
   50 CONTINUE
      RETURN
      END
```

```
      SUBROUTINE LPGOGO
      DIMENSION COSTPO(10,5),P(10,10),NEWP(10), POWEXI(10),
     1B(52),JCOL(100),IROW(50),IBASIS(50),ITITLE(12),PEX(50),
     1PWD(7,50),PSD(7,50),PSDM(10,5),PCOS(10,50),ELAS(10),PPC(10),
     1IROW1(100),X1(100),PRES(10),PSDIN(10),POP(10,50),POPMAX(10),
     1GROW(10),A(52,150),PPC1(10),STACK(10),POPX(10,50),TR(10,10),
     1DPOP(10),PADD(10),IDUP(150),JDUP(150),VALDUP(150),PSOLD(10,50),
     1CON(10),GROCON(10)
      COMMON T,A,B,JCOL,IROW,IBASIS,ITITLE,M,N,NSTA,PEX,PWD,PSD,
     1P,NEWP,POWEXI,PCOS,ELAS,PPC,PPC1,STACK,LOSS,VAL,POPX,NTYPE,
     1IROW1,X1,MPLUS2,NM,NYEAR,PRES,PSDIN,POPMAX,POP,GROW,TR,PADD,
     1COSTPO,PSDM,IDUP,JDUP,VALDUP,INOFES,ICHECK,PSOLD,CON,GROCON
      INTEGER T,STACK
      REAL NEWP,LOSS
C     LPGOGO MAXIMIZES A LINEAR FUNCTION SUBJECT TO LINEAR EQUATIONS.
C     ALL RHS PARAMETERS MUST BE NONNEGATIVE.
      DATA KBASIC/5HBASIC/
      DATA LBASIC/5H     /
      DATA MBASIC/6HBINDNG/
      DATA NBASIC/5HSLACK/
      DATA ISOLVE/6HSOLVE /
C     INPUT
      ISTOP = 0
      ITERS = 0
      IA1 =0
      IB1 = 0
      DO 5 I=1,MPLUS2
      IBASIS(I) = 0
    5 CONTINUE
      IF(T .GE. 1) ICHECK = 2
C     READ EQUATION NAMES AND NON-NEGATIVE RHS PARAMETERS
      IF(T .GT. 1) GO TO 12
      READ(5,2003)(IROW(I),I=1,M)
      READ(5,2004)(JCOL(J),J=1,N)
 2004 FORMAT(8X,A6)
 2003 FORMAT(A6)
   12 GO TO (10,50),ICHECK
   10 WRITE(6,1103)(IROW(I),B(I),I=1,M)
      WRITE(6,1104)(JCOL(J),A(M+1,J),J=1,N)
C     READ LHS COEFFICIENTS
   50 I2=0
      J2=0
      IF(T .NE. 1) GO TO 240
      IB1 = IB1 + 1
      READ(5,1005)IDUP(IB1),JDUP(IB1),VALDUP(IB1)
      I = IDUP(IB1)  $ J =JDUP(IB1)    $  VALUE = VALDUP(IB1)
      IF(I .EQ. ISOLVE) GO TO 99
      GO TO 245
  240 IB1 = IB1 + 1
      I = IDUP(IB1)  $ J = JDUP(IB1)    $ VALUE = VALDUP(IB1)
      IF(I .EQ. ISOLVE) GO TO 99
  245 DO 60 I1 = 1,M
      IF( I .EQ. IROW(I1)) GO TO 62
   60 CONTINUE
      GO TO 700
```

```
   62 I2 = I1
      DO 65 J1 = 1,N
      IF(J .EQ. JCOL(J1)) GO TO 66
   65 CONTINUE
      GO TO 70C
   66 J2 = J1
   90 A(I2,J2)=VALUE
      GO TO 50
   99 WRITE(6,1107)
      IF(ISTOP.EQ.1) GO TO 1
  100 CONTINUE
      GO TO (20,21),ICHECK
   20 WRITE(6,1105)(IDUP(LC),JDUP(LC),VALDUP(LC),LC=1,IB1)
   21 K=2
      N1=N+1
C     SETUP PHASE I ROW
      DO 120 J=1,N
      A(M+2,J) =0.0
      DO 120 I=1,M
      A(M+2,J)=A(M+2,J)+A(I,J)
  120 CONTINUE
C     SET UP INITIAL BASIS AND ARTIFICIALS
      DO 110 I=1,M
      NPLUSI = N + I
      A(I,NPLUSI) = 1.0
      IBASIS(I)=0
      B(M+2) = B(M+2)+B(I)
  110 CONTINUE
C     FIND PIVOT COLUMN
  399 DPS=0.0
      MPLUSK = M + K
  400 DO 410 J=1,N
405   IF(A(MPLUSK,J)-DPS)410,410,420
  420 DPS = A(MPLUSK,J)
      JPIV=J
  410 CONTINUE
      IF(DPS-1.0E-06) 501,501,450
C     FIND PIVOT ROW
  450 RATMIN = 1.0E+06
      IPIV=M + 3
      DO 470 I=1,M
      IF(A(I,JPIV).LE.1.0E-06) GO TO 470
      RATIO = B(I)/A(I,JPIV)
      IF(RATIO.GE.RATMIN) GO TO 470
      RATMIN = RATIO
      IPIV=I
  470 CONTINUE
      IF(K.EQ.2) GO TO 475
      DO 475 I=1,M
      IF(IBASIS(I).NE.0) GO TO 475
      IF(ABS(A(I,JPIV)).LE.1.0E-06) GO TO 475
      IPIV = I
  475 CONTINUE
      PIVOT = A(IPIV,JPIV)
      IBASIS(IPIV) = JPIV
      ITERS=ITERS+1
```

```
C     IF PIVOT FOUND, TRANSFORM TABLEAU
C     IF NOT, EXIT, SOLUTION UNBOUNDED
      IF(IPIV.EQ.M+3) GO TO 496
      DO 500 I = 1,MPLUSK
      IF(I.EQ.IPIV) GO TO 500
      DO 480 J=1,NM
      IF(J.EQ.JPIV) GO TO 480
      A(I,J)=A(I,J)-A(I,JPIV)*A(IPIV,J)/PIVOT
  480 CONTINUE
      B(I)=B(I)-A(I,JPIV)*B(IPIV)/PIVOT
      A(I,JPIV) = 0.0
  500 CONTINUE
      B(IPIV)=B(IPIV)/PIVOT
      DO 495 J=1,NM
      A(IPIV,J)=A(IPIV,J)/PIVOT
  495 CONTINUE
      GO TO 399
  496 WRITE(6,1006)
       INOFES = 4
      GO TO 571
  501 IF(K.EQ.1) GO TO 510
      IF(B(M+2)-1.0E-03) 504,504,505
C     NO FEASIBLE SOLUTION EXISTS
  505 WRITE(6,1007)
       INOFES = 2
      GO TO 571
  504 K=1
      GO TO 399
C     OPTIMAL SOLUTION OUTPUT
  510 CONTINUE
      WRITE(6,1008) ITERS
      ZIMBOX = -B(M+1)
      WRITE(6,1010)ZIMBOX
       GO TO(650,651),ICHECK
  650 WRITE(6,1011)
  651 DO 580 J=1,N
      JCOLJ = JCOL(J)
      DELTAJ = A(M+1,J)
      DO 520 I=1,M
      II=I
      IF(IBASIS(I).EQ.J) GO TO 550
  520 CONTINUE
      X=0.0
      JBASIC = LBASIC
      GO TO 560
  550 X = B(II)
      JBASIC = KBASIC
  560 IA1 = IA1 + 1
         IROW1(IA1)=IROWI     $ X1(IA1)=X
       IF(T .GT. 1) GO TO 580
      WRITE(6,1009) JCOLJ,JBASIC,X,DELTAJ
  580 CONTINUE
  561  GO TO(660,661),ICHECK
  660  WRITE(6,1012)
  661 DO 570 I=1,M
      JBASIC = MBASIC
```

```
      IROWI=IROW(I)
      NPLUSI=N+I
      X = -A(M+1,NPLUSI)
      IF(ABS(X) - 1.0E-09)562,562,606
  562 IF(IBASIS(I))564,563,564
  563 JBASIC =LBASIC
      FLOWER = 0.0
      FUPPER = 0.0
      GO TO 569
  564 JBASIC = NBASIC
  606 FLOWER = -1.0E+10
      FUPPER = 1.0E+10
      DO 900 K=1,M
      IF(A(K,NPLUSI))601,900,605
  601 QUOT = -B(K)/A(K,NPLUSI)
      IF(QUOT.GE.FUPPER) GO TO 900
      FUPPER = QUOT
      GO TO 900
  605 QUOT = -B(K)/A(K,NPLUSI)
      IF(QUOT.LE.FLOWER) GO TO 900
      FLOWER = QUOT
  900 CONTINUE
      FLOWER = -FLOWER
      IF(FLOWER.EQ.+1.0E+10.AND.FUPPER.LT.1.0E+10)GO TO 574
      IF(FLOWER.LT.+1.0E+10.AND.FUPPER.EQ.1.0E+10)GO TO 576
      IF(FLOWER.EQ.+1.0E+10.AND.FUPPER.EQ.1.0E+10)GO TO 572
C        NOTE   THE FOLLOWING FOUR STATEMENTS ARE CHANGED TO SUPRESS
C        OUTPUT FROM LPGOGO AFTER T=5
C        TO GET THE ORIGINALCHANGE STATE  NOS TO THE FOLLOWING  IF  CARD
  569 IF(T .GT. 1) GO TO 5691
C 569 WRITE(6,1013)IROWI,JBASIC,X,FLOWER,FUPPER
      WRITE(6,1013)IROWI,JBASIC,X,FLOWER,FUPPER
 5691  IA1 = IA1+1
      GO TO 570
  572 IF(T .GT. 1) GO TO 5721
C 572 WRITE(6,1017)IROWI,JBASIC,X
      WRITE(6,1017)IROWI,JBASIC,X
 5721  IA1=IA1+1
      GO TO 570
  574 IF(T .GT. 1) GO TO 5741
C 574 WRITE(6,1018)IROWI,JBASIC,X,FUPPER
      WRITE(6,1018)IROWI,JBASIC,X,FUPPER
 5741    IA1 =IA1 + 1
      GO TO 570
  576 IF(T .GT. 1) GO TO 5761
C 576 WRITE(6,1019)IROWI,JBASIC,X,FLOWER
      WRITE(6,1019)IROWI,JBASIC,X,FLOWER
 5761    IA1 =IA1 + 1
  570 CONTINUE
C     FULL TABLEAU PRINTOUT AVAILABLE BY REMOVING THE FOLLOWING CARD.
      GO TO 1
  571 WRITE(6,1015)
      MPLUS2 = M + 2
      DO 800 I = 1,MPLUS2
      WRITE(6,1016)(A(I,J),J=1,NM),B(I)
  800 CONTINUE
```

```
      WRITE(6,1015)
      GO TO 1
  700 WRITE(6,1014)
      ISTOP = 1
      INOFES = 3
      GO TO 50
 1003 FORMAT(12X,A6,1X,F10.0)
 1004 FORMAT(8X,A6,2X,F12.6)
 1005 FORMAT(A6,2X,A6,2X,F12.6)
 1006 FORMAT(19H SOLUTION UNBOUNDED)
 1007 FORMAT(21H NO FEASIBLE SOLUTION)
 1008 FORMAT(23H1SOLUTION OPTIMAL AFTER,2X,I5,11H ITERATIONS)
 1009 FORMAT(4X,A6,2X,A5,5X,F12.6,4X,F12.6)
 1010 FORMAT(20H MAXIMAL OBJECTIVE = ,F16.5)
 1011 FORMAT(2X,8HVARIABLE,2X,6HSTATUS,8X,5HVALUE,9X,6HDELTAJ)
 1012 FORMAT(11H0CONSTRAINT,1X,6HSTATUS,8X,5HVALUE,9X,8HDECREASE,9X,8HIN
     1CREASE)
 1013 FORMAT(4X,A6,2X,A6,4X,F12.6,4X,F12.6,4X,F12.6)
 1014 FORMAT(18H INCONSISTENT NAME)
 1015  FORMAT(10X,////)
 1016 FORMAT(1X,8F14.7)
 1017 FORMAT(4X,A6,2X,A6,4X,F12.6,4X,12H     OPEN     ,4X,12H     OPEN     )
 1018 FORMAT(4X,A6,2X,A6,4X,F12.6,4X,12H     OPEN     ,4X,F12.6)
 1019 FORMAT(4X,A6,2X,A6,4X,F12.6,4X,F12.6,4X,12H     OPEN     )
 1103 FORMAT(1XA6,10X,F12.6)
 1104 FORMAT(9X,A6,2X,F12.6)
 1105 FORMAT(1XA6,2X,A6,2X,F12.6)
 1107 FORMAT(1X,5HSOLVE)
    1 RETURN
      END
```

```
      SUBROUTINE DYNAMI
      DIMENSION COSTPO(10,5),P(10,10),NEWP(10), POWEXI(10),
     1B(52),JCOL(100),IROW(50),IBASIS(50),ITITLE(12),PEX(50),
     1PWD(7,50),PSD(7,50),PSDM(10,5),PCOS(10,50),ELAS(10),PPC(10),
     1IROW1(100),X1(100),PRES(10),PSDIN(10),POP(10,50),POPMAX(10),
     1GROW(10),A(52,150),PPC1(10),STACK(10),POPX(10,50),TR(10,10),
     1DPOP(10),PADD(10),IDUP(150),JDUP(150),VALDUP(150),PTRIN(10),
     1PTR(10,50),EQUL(10,50),PPROD(10),PSOLD(10,50),CON(10),GROCON(10)
      COMMON T,A,B,JCOL,IROW,IBASIS,ITITLE,M,N,NSTA,PEX,PWD,PSD,
     1P,NEWP,POWEXI,PCOS,ELAS,PPC,PPC1,STACK,LOSS,VAL,POPX,NTYPE,
     1IROW1,X1,MPLUS2,N1,NYEAR,PRES,PSDIN,POPMAX,POP,GROW,TR,PADD,
     1COSTPO,PSDM,IDUP,JDUP,VALDUP,INOFES,ICHECK,PSOLD,CON,GROCON
       INTEGER T,STACK
       REAL NEWP,LOSS
C         THESE DATA MAY BE SUPPLIED IN READ
       DATA NBACK/5/
       DATA CONST/.03/
       L = 0
      IFLAG = 2
       VAL = 0.1
       LOSS = 0.05
C         ARRAY X1(L) CONTAINS OPTIMISED OUTPUT FROM LPGOGO.  IT IS REARR
C         INTO ARRAY P(I,J)  POWER TRANSMITTED FROM STATION I TO STATION
       DO 20 I=1,NSTA
       DO 20 J=1,NSTA
       L = L + 1
       P(I,J)= X1(L)
   20 CONTINUE
C         FINDS  THE POWER PRODUED PLUS THE POWER TRANSMITTED
C         NEWP(I)  IS THE POWER PRODUED PLUS TRANSMITTED
       DO 40 I=1,NSTA
       SUM = 0.0
       DO 41 J=1,NSTA
       SUM = SUM+P(I,J)
   41 CONTINUE
       NEWP(I) = SUM
   40 CONTINUE
C         FINDS THE TOTAL POWER PRODUCED
       DO 50 J = 1,NSTA
       PSD(J,T)    = NEWP(J)*(1.+LOSS)
   50 CONTINUE
C         FINDS THE SELLING PRICE OF POWER
       DO 500 I=1,NSTA
        SUM1 = 0.0
       SUM = 0.0
       DO 510 J=1,NSTA
       IF(I . EQ. J) GO TO 520
       SUM = SUM + P(J,I)*(TR(J,I)+PCOS(J,T))
       SUM1 = SUM1 + P(J,I)
       GO TO 510
  520  SUM = SUM + ((PCOS(I,T)+TR(I,J))*P(I,J))
       SUM1 = SUM1 + P(I,J)
  510  CONTINUE
       PSOLD(I,T) = SUM/SUM1
  500 CONTINUE
```

```
      WRITE(6,211)T
      T=T+1
      WRITE(6,214)
      WRITE(6,215)
      I = 1
  212 WRITE(6,213)I,(P(I,J),J=1,NSTA)
      I = I + 1
      IF(I .LE.NSTA) GO TO 212
      IF(T .NE. 2) GO TO  400
      WRITE(6,210)
      DO 218 I=1,NSTA
      WRITE(6,219)PWD(I,T-1),PSD(I,T-1),PSOLD(I,T-1),POP(I,T-1)
      PPROD(I) = PSD(I,T-1)
  218 CONTINUE
      GO TO 470
  400  WRITE(6,210)
C        IF THE PRESENT POWER PRODUCTION IS LE      AN PREVIOUS YEARS AT
C        REGION THE PREVIOUS YEARS VALUE ARE U   .  IN THE OUTPUT DOUBLE
C        ASTRITCH (**) IN THE COLOUM PSD DENOTES THIS
      DO 415 I=1,NSTA
      IF(PPROD(I) .LE. PSD(I,T-1)) GO TO 191
      PSD(I,T-1) = PPROD(I)
      IFLAP = 1
      GO TO 425
  191  IFLAP = 2
      PPROD(I) = PSD(I,T-1)
  425  IF(ELAS(I) .LE. VAL .AND. IFLAP .EQ. 1)GO TO 430
      IF(ELAS(I) .LE. VAL .AND. IFLAP .EQ. 2)GO TO 435
      IF(ELAS(I) .GT. VAL .AND. IFLAP .EQ. 1)GO TO 440
      IF(ELAS(I) .GT. VAL .AND. IFLAP .EQ. 2)GO TO 445
  430 WRITE(6,450)PWD(I,T-1),PSD(I,T-1),PSOLD(I,T-1),POP(I,T-1),
     1ELAS(I),EQUL(I,T-1)
      GO TO 415
435   WRITE(6,451)PWD(I,T-1),PSD(I,T-1),PSOLD(I,T-1),POP(I,T-1),
     1ELAS(I),EQUL(I,T-1)
      GO TO 415
  440 WRITE(6,452)PWD(I,T-1),PSD(I,T-1),PSOLD(I,T-1),POP(I,T-1),
     1ELAS(I),EQUL(I,T-1)
      GO TO 415
  445 WRITE(6,453)PWD(I,T-1),PSD(I,T-1),PSOLD(I,T-1),POP(I,T-1),
     1ELAS(I),EQUL(I,T-1)
      GO TO 415
  415 CONTINUE
  470 DO 220 I=1,NSTA
      SUM = 0.0
      DO 221 J=1,NSTA
      IF(I .EQ. J) GO TO 221
      SUM = SUM + P(J,I)
  221 CONTINUE
      PTR(I,T-1) = SUM
  220 CONTINUE
C        FIND WEATHER HIHER COST OF PRODUCTION IS REQUIRED
      DO 130 I=1,NSTA
C        IN THE NEXT STATEMENT , NOT SURE PSD OR NEWP
C        IF THE POWER DEMAND IS LARGER THAN POWER SUPPLIED
C        THEN A POWER UNIT OF 1 MW IS ADDED TO THAT STATION
```

```
  132  IF(PSD(I,T-1) .GE. POWEXI(I)) GO TO 131
       GO TO 130
  131  PADD(I) = PADD(I) + 1.
       POWEXI(I) = POWEXI(I) +1.
   15  MI =STACK(I)
       IF(MI .EQ. 1) GOTO 13
       IF(PSDM(I,MI) .GE. PADD(I))  GO TO 132
       IF(PSDM(I,MI) .EQ. 0.0) GO TO 14
       PADD(I)=1.
       STACK(I) = STACK(I) + 1
       GO TO 132
   13  IF(PSDM(I,MI) .LT. POWEXI(I)) STACK(I) =STACK(I) + 1
       GO TO 132
   14 STACK(I) = STACK(I) + 1
       GO TO 15
  130 CONTINUE
C         CALCULATES ELAS,EQUL,PPC,DPOP,PWC,POP FROM THE PREVIOUSLY CALCU
C         DATA
      DO 140 I = 1,NSTA
      SUM = 0.0
      MC = STACK(I)
      DO 141 J = 1,MC
      SUM = SUM + PSDM(I,J)
  141 CONTINUE
      PTRIN(I) = SUM
  140 CONTINUE
       DO 70 J = 1,NSTA
C         NOTE   ELAS   SET   TO  1.   AND PSDIN(J) SET TO PTRIN(J)
C         ****************
C     ELAS(J) = 1.4 -(0.4*(PSOLD(J,T-1)/PSOLD(J,1)))
       ELAS(J) = 1.0
       PTRIN(J) = PSDIN(J)
       EQUL(J,T) = (1.-(PTR(J,T-1)/PSDIN(J)))*
     1(1.-(PSD(J,T-1)/PTRIN(J)))
       IF( T .LT. 7) GO TO 200
       GROW(J) = GROCON(J) * EQUL(J,T-NBACK)
  200  IF(ELAS(J) .LT. VAL) IFLAG = 1
       PPC(J)=CON(J)* (POP(J,T-1)/POP(J,1))
       DPOP(J) = (POP(J,T-1)*GROW(J)*(POPMAX(J)-POP(J,T-1)))-POPX(J,T)
       PWD(J,T) = (PWD(J,T-1) +(DPOP(J)*PPC(J))) * ELAS(J)
       POP(J,T) = POP(J,T-1) + DPOP(J)
       IF(IFLAG .NE. 1)GO TO 70
       WRITE(6,90)J
       ELAS(J) =0.1
   70 CONTINUE
       ICHECK = 1
       GO TO (485,486),ICHECK
  485  WRITE(6,154)(PTR(J,T-1),J=1,NSTA)
       WRITE(6,155)(PTRIN(J),J=1,NSTA)
       WRITE(6,156)(GROW(J),J=1,NSTA)
      WRITE(6,150) (PWD(J,T),J=1,NSTA)
       WRITE(6,151)(PPC(J),J=1,NSTA)
       WRITE(6,152)(DPOP(J),J=1,NSTA)
       WRITE(6,153)(PADD(J),J=1,NSTA)
       WRITE(6,158)(STACK(I),I=1,NSTA)
       WRITE(6,159)(POWEXI(I),I=1,NSTA)
```

```
      WRITE(6,160)(PCOS(J,T-1),J=1,NSTA)
160 FORMAT(3X,*PCOS J,T*,7(5X,F12.4))
158 FORMAT(5X,*STACK*,7(5X,I12))
159 FORMAT(5X,*POWEXI*,7(5X,F12.4))
153  FORMAT(5X,*PADD *,7(5X,F12.4))
150 FORMAT(7X,*PWD*,7(5X,F12.4))
151 FORMAT(7X,*PPC*,7(5X,F12.4))
152 FORMAT(5X,*DPOP*,7(5X,F12.4))
154 FORMAT(5X,//.3X,*PTR J,T-1*,7(5X,F12.4))
155 FORMAT(5X,*PTRIN*,7(5X,F12.4))
156  FORMAT(5X,*GROW*,7(5X,F12.4))
213 FORMAT(3X,I5,2X,7(5X,F12.4))
219 FORMAT(5X,4(5X,F15.4))
211 FORMAT(1H6,15X* CALCULATION FOR THE YEAR   *I5,//)
214 FORMAT(10X,*POWER DISTRIBUTION BETWEEN STATIONS    *,//)
215 FORMAT(15X,1H1,17X,1H2,17X,1H3,17X,1H4,17X,1H5,17X,1H6,17X,1H7,//)
216 FORMAT(5X,I5,7(5X,F12.4))
210 FORMAT(10X,//,10X,*POWER DEMAND  *,5X,*POWER SUPPLIED *,10X,*POWER
   1COST    *,9X,*POPULATION*,6X,*  ELASTICITY  *,13X,*EQUL  *,//)
450 FORMAT(5X,2(5X,F15.4),1X,2H**,2X,F15.4,2(5X,F15.4),1X,2H**,2X,
   1F15.4)
451  FORMAT(5X,4(5X,F15.4),1X,2H**,2X,F15.4,5X,F15.4)
452  FORMAT(5X,2(5X,F15.4),1X,2H**,2X,F15.4,3(5X,F15.4))
453  FORMAT(5X,6(5X,F15.4))
 90 FORMAT(10X,*ELASTICITY OF REGION*,I3,2X,*LESS THAN 0.1  CHECK*)
    ICHECK = 2
486  RETURN
    END
```

```
      SUBROUTINE PLOTRO
     DIMENSION COSTPO(10,5),P(10,10),NEWP(10), POWEXI(10),
    1B(52),JCOL(100),IROW(50),IBASIS(50),ITITLE(12),PEX(50),
    1PWD(7,50),PSD(7,50),PSDM(10,5),PCOS(10,50),ELAS(10),PPC(10),
    1IROW1(100),X1(100),PRES(10),PSDIN(10),POP(10,50),POPMAX(10),
    1GROW(10),A(52,150),PPC1(10),STACK(10),POPX(10,50),TR(10,10),
    1DPOP(10),PADD(10),IDUP(150),JDUP(150),VALDUP(150),PSOLD(10,150),
    1IMAGE(867),CON(10),GROCON(10)
     COMMON T,A,B,JCOL,IROW,IBASIS,ITITLE,M,N,NSTA,PEX,PWD,PSD,
    1P,NEWP,POWEXI,PCOS,ELAS,PPC,PPC1,STACK,LOSS,VAL,POPX,NTYPE,
    1IROW1,X1,MPLUS2,NM,NYEAR,PRES,PSDIN,POPMAX,POP,GROW,TR,PADD,
    1COSTPO,PSDM,IDJP,JDUP,VALDUP,INOFES,ICHECK,PSOLD,CON,GROCON
      INTEGER T,STACK
      REAL NEWP,LOSS
     XMAX = NYEAR
     XMIN = 1.
      I= 1
 70   WRITE(6,80)I
      WRITE(6,100)
      DO 85 J=1,NYEAR
 85   WRITE(6,90)PWD(I,J),PSD(I,J),PSOLD(I,J),POP(I,J)
      CALL PLOT2(IMAGE,XMAX,XMIN,5.0,0.0)
      WRITE(6,60)
      WRITE(6,61)I
      DO 50 J=1,NYEAR
      TIME = J
      PE1 = POP(I,J)
      PS1 = PSD(I,J)
      COST = PSOLD(I,J)
      PW1 = PWD(I,J)
      CALL PLOT3(1HP,TIME,PE1,1)
      CALL PLOT3(1HS,TIME,PS1,1)
      CALL PLOT3(1HC,TIME,COST,1)
      CALL PLOT3(1HD,TIME,PW1,1)
 50  CONTINUE
      CALL PLOT4(43,43H  POPULATION,POWER SUP,POWER COST,POWER DEM)
      WRITE(6,62)
      I = I + 1
      IF (I .GT. NSTA) GO TO 72
      GO TO 70
 72  RETURN
100   FORMAT(5X,*POWER DEMAND  *,5X,*POWER SUPPLIED *,5X,*  POWER COST
    1   *,5X,*  POPULATION   *,///)
 80   FORMAT(1H1,10X,*  COMPRESSED OUTPUT   DATA USED FOR PLOTTING
    1FOR THE REGION*,I5,///)
 90   FORMAT(5X,4(5X,F15.4))
 60  FORMAT(1H1,30X*TIME V POPULATION, POWER SUPPLIED, POWER COST AND P
    2OWER DEMAND*//)
 62   FORMAT(10X,/,10X,*P = POPULATION*10X* S = POWER PRODUCED*10X* C =
    2 POWER COST*10X* D = POWER DEMAND*/)
 61  FORMAT(10X,*PLOT FOR THE REGION*,I5,/)
      END
```

POWER DISTRIBUTION PROBLEM

NO OF CONSTRAINTS = 14
NO OF VARIABLES = 56
NO FO YEAR = 15
NO OF GENERAING STATIONS = 7
NO OF TYPES OF POWER PRODUCTIONS = 4

COST OF PRODUCTION POWER BY VARIOUS METHODS

STATION	HYDRO	ONCE THR	COOL TOW	DRY
1	2.0000	5.0000	7.0000	13.0000
2	2.0000	4.0000	5.5000	11.5000
3	2.0000	4.0000	5.5000	11.5000
4	2.0000	0.0000	6.0000	12.0000
5	2.0000	5.0000	6.5000	12.5000
6	2.0000	5.0000	6.5000	12.5000
7	2.0000	5.0000	6.5000	12.5000

TRANSMISSION COST REGION I TO REGION J

	1	2	3	4	5	6	7	
1	.1500	.1500	.2700	.2700	.3000	.3300	.3300
2	.1500	.1500	.2700	.2700	.3000	.3300	.3300
3	.2700	.1500	.1500	.3000	.2700	.2700	.3000
4	.2700	.1500	.1500	.1500	.2700	.3300	.3300
5	.3000	.3000	.2700	.3000	.1500	.2700	.3000
6	.3300	.3300	.2700	.2700	.1500	.1500	.2700
7	.3300	.3300	.2700	.2700	.3000	.2700	.1500

STATION	MAXHYD	MAXONCE THR	MAX COOL TOW	MAX DRY
1	2.0000	5.0000	5.0000	20.0000
2	0.0000	2.0000	5.0000	20.0000
3	10.0000	3.0000	10.0000	20.0000
4	1.0000	0.0000	5.0000	20.0000
5	5.5000	1.0000	5.0000	20.0000
6	2.0000	1.0000	5.0000	20.0000
7	.7000	1.0000	5.0000	20.0000

PSDIN	32.0000	27.0000	43.0000	16.0000	32.0000	28.0000	27.0000
POP(J,1)	1.9000	1.2000	.4000	.6000	.6000	.6000	.2000
POPMAX	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000
GROW	.0230	.0150	.0120	.0230	.0180	.0130	.0180
EXISITING POWER	2.0000	2.0000	10.0000	1.0000	5.5000	2.0000	7.0000
CON	1.0925	1.5300	.7800	1.1967	.3633	1.3633	1.0300

SOLVE

SOLUTION OPTIMAL AFTER 27 ITERATIONS
MAXIMAL OBJECTIVE = -24.325000

P11	BASIC	.700000	0.000000
P12	BASIC	1.300000	0.000000
P13		0.000000	-2.270000
P14		0.000000	-.120000
P15		0.000000	-.150000
P16		0.000000	-.180000
P17		0.000000	-.180000
P21	BASIC	1.800000	0.000000
P22		0.000000	-.090000
P23		0.000000	-.120000
P24		0.000000	-.120000
P25		0.000000	-.150000
P26		0.000000	-.180000
P27		0.000000	-.180000
P31		0.000000	-.120000
P32	BASIC	.300000	0.000000
P33		0.000000	0.000000
P34		0.000000	-.150000
P35		0.000000	-.120000
P36		0.000000	-.120000
P37		0.000000	-.150000
P41		0.000000	-.120000
P42	BASIC	.700000	0.000000
P43	BASIC	.800000	0.000000
P44	BASIC	1.200000	0.000000
P45		0.000000	-.120000
P46		0.000000	-.180000
P47		0.000000	-.180000
P51		0.000000	-.150000
P52		0.000000	-.150000
P53		0.000000	-.120000
P54		0.000000	-.150000
P55	BASIC	.700000	0.000000
P56		0.000000	-.120000
P57		0.000000	-.150000
P61		0.000000	-.180000
P62		0.000000	-.180000
P63		0.000000	-.120000
P64		0.000000	-.120000
P65		0.000000	0.000000
P66	BASIC	1.300000	0.000000
P67		0.000000	-.120000
P71		0.000000	-.180000
P72		0.000000	-.180000
P73		0.000000	-.120000
P74		0.000000	-.120000
P75		0.000000	-.150000
P76		0.000000	-.120000
P77	BASIC	.700000	0.000000

SLACK1		0.000000	0.000000	
SLACK2		0.000000	-2.000000	
SLACK3		0.000000	0.000000	
SLACK4	BASIC	2.000000	0.000000	
SLACK5	BASIC	.500000	0.000000	
SLACK6	BASIC	.500000	0.000000	
SLACK7	BASIC	.500000	0.000000	
PWDSL1		0.000000	-2.150000	
PWDSL2		0.000000	-4.150000	
PWDSL3		0.000000	-2.150000	
PWDSL4		0.000000	-2.150000	
PWDSL5		0.000000	-2.150000	
PWDSL6		0.000000	-2.150000	
PWDSL7		0.000000	-2.150000	
PWD1	BINDNG	-2.150000	.700000	OPEN
PWD2	BINDNG	-4.150000	1.300000	.700000
PWD3	BINDNG	-2.150000	.300000	.700000
PWD4	BINDNG	-2.150000	1.200000	OPEN
PWD5	BINDNG	-2.150000	.700000	OPEN
PWD6	BINDNG	-2.150000	1.300000	OPEN
PWD7	BINDNG	-2.150000	.700000	OPEN
PSD1	SLACK	-0.000000	.700000	1.300000
PSD2	BINDNG	2.000000	.700000	1.300000
PSD3	SLACK	-0.000000	.700000	.300000
PSD4	SLACK	-0.000000	2.000000	OPEN
PSD5	SLACK	-0.000000	.500000	OPEN
PSD6	SLACK	-0.000000	.500000	OPEN
PSD7	SLACK	-0.000000	.500000	OPEN

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CALCULATION FOR THE YEAR 1

POWER DISTRIBUTION BETWEEN REGIONS

	1	2	3	4	5	6	7
1	.7000	1.3000	0.0000	0.0000	0.0000	0.0000	0.0000
2	1.8000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	0.0000	.3000	0.0000	0.0000	0.0000	0.0000	0.0000
4	0.0000	.7000	.8000	1.2000	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	.7000	0.0000	0.0000
6	0.0000	0.0000	0.0000	0.0000	0.0000	1.3000	0.0000
7	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	.7000

POWER DEMAND	POWER SUPPLIED	POWER COST	POPULATION	ELASTICITY	EQUL
2.0000	2.1000	3.5900	1.9000		
1.8000	1.8900	2.1500	1.2000		
.3000	.3150	2.1500	.4000		
.7000	2.8350	2.1500	.6000		
.2000	.7350	2.1500	.6000		
.8000	1.3550	2.1500	.6000		
.2000	.7350	2.1500	.2000		

PTR(J,T-1)	1.8000	2.3000	.8000	0.0000	0.0000	0.0000	0.0000
PTRIN	32.0000	27.0000	43.0000	16.0000	32.0000	28.0000	27.0000
GROW	.0230	.0130	.0120	.0230	.0190	.0130	.0080
PWD	2.1457	1.8907	.3172	.7727	.2173	.8468	.2179
PPC	1.0826	1.5300	.7800	1.1967	.3633	1.3633	1.0300
DPOP	.1355	.0593	.0221	.0607	.0475	.0343	.0077
PADD	1.0000	1.0000	0.0000	2.0000	0.0000	0.0000	0.0000
STACK	2	2	1	3	1	1	1
POWEXI	3.0000	2.0000	10.0000	3.0000	5.5000	2.0000	7.0000
PCOS(J,T)	2.0000	4.0000	2.0000	2.0000	2.0000	2.0000	2.0000

SOLVE

SOLUTION OPTIMAL AFTER 30 ITERATIONS

MAXIMAL OBJECTIVE = -53.356798

CALCULATION FOR THE YEAR 2

POWER DISTRIBUTION BETWEEN REGIONS

	1	2	3	4	5	6	7
1	.7560	.8907	0.0000	.5000	0.0000	0.0000	0.0000
2	1.8907	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	0.0000	1.5000	.8172	0.0000	0.0000	0.0000	0.0000
4	0.0000	0.0000	0.0000	.7727	0.0000	0.0000	0.0000
5	0.0000	0.0000	0.0000	0.0000	.7173	0.0000	0.0000
6	0.0000	0.0000	0.0000	0.0000	0.0000	1.3468	0.0000
7	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	.7079

POWER DEMAND	POWER SUPPLIED	POWER COST	POPULATION	ELASTICITY	EQUL
2.1467	2.2540	3.8644	2.0355	1.0000	.3818
1.8907	1.9852	2.5226	1.2593	1.0000	.3538
.3172	2.4331	2.1500	.4221	1.0000	.3742
.7727	2.4331 **	4.2096	.6607	1.0000	.3228
.2173	.7531	2.1500	.6475	1.0000	.3770
.8468	1.4141	2.1500	.6343	1.0000	.3512
.2079	.7433	2.1500	.2077	1.0000	.3728

PTR(J,T-1)	1.3907	2.3907	0.0000	.5000	0.0000	0.0000	0.0000
PTRIN	32.0000	27.0000	43.0000	16.0000	32.0000	28.0000	27.0000
GROW	.0230	.0130	.0120	.0230	.0180	.0130	.0080
PWD	2.3076	1.9830	.3363	.8595	.2372	.8987	.2164
PPC	1.1598	1.6036	.8231	1.3178	.3921	1.4413	1.0596
DPOP	.1388	.0612	.0232	.0659	.0507	.0360	.0030
PADD	1.0000	1.0000	0.0000	2.0000	0.0000	0.0000	0.0000
STACK	2	2	1	3	1	1	1
POWEXI	3.0000	2.0000	10.0000	3.0000	5.5000	2.0000	7.0000
PCOS(J,T)	3.0000	4.0000	2.0000	4.6667	2.0000	2.0000	2.0000

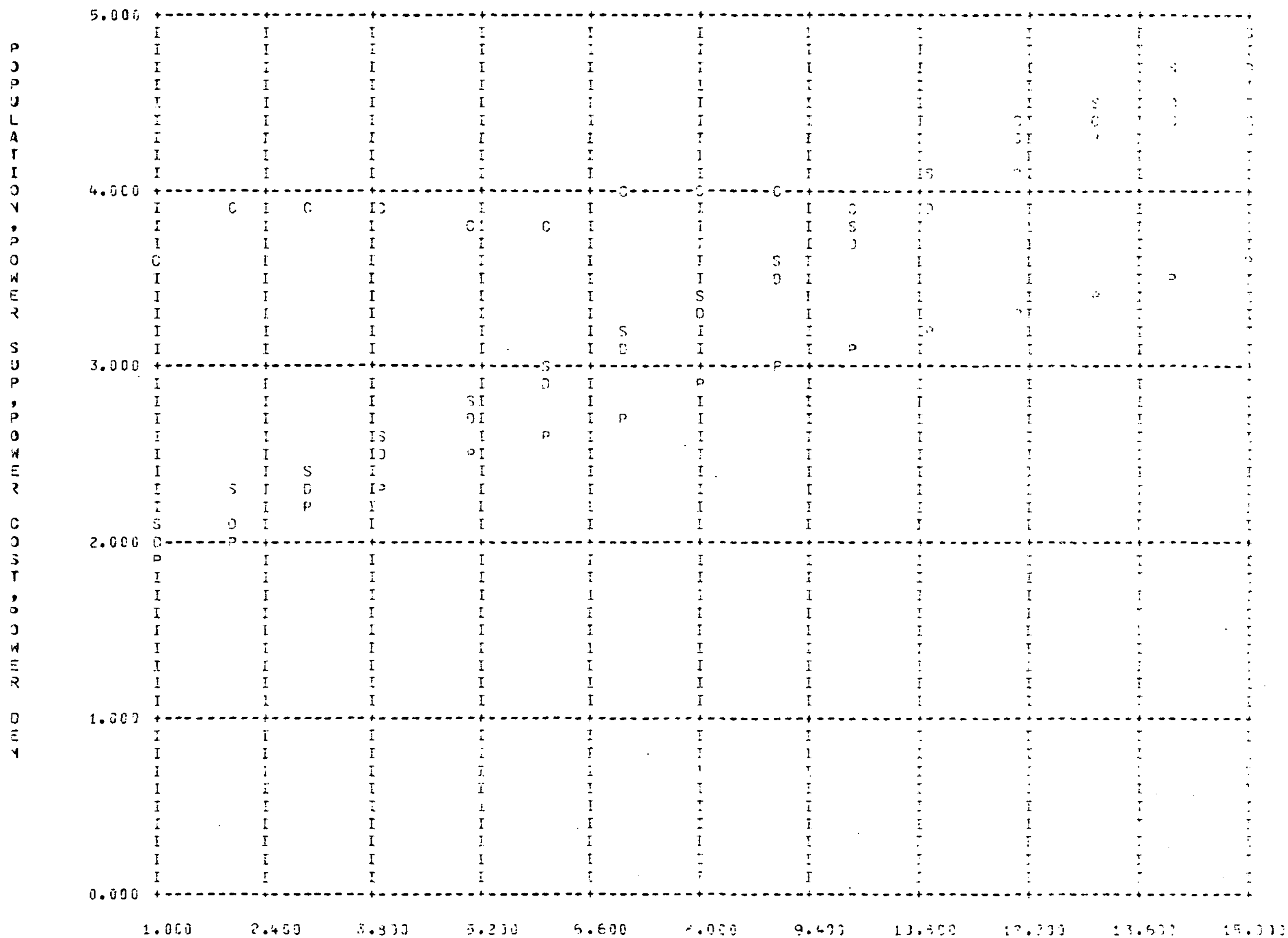
SOLVE

COMPRESSED OUTPUT DATA USED FOR PLOTTING FOR THE REGION 1

POWER DEMAND	POWER SUPPLIED	POWER COST	POPULATION
2.0000	2.1000	3.5900	1.9000
2.1467	2.2540	3.8644	2.0355
2.3076	2.4230	3.8584	2.1743
2.4827	2.6068	3.8525	2.3156
2.6713	2.8049	3.8469	2.4585
2.8727	3.0163	3.8419	2.6022
3.0603	3.2133	3.9936	2.7288
3.2542	3.4169	3.9917	2.8535
3.4527	3.6253	3.9903	2.9756
3.6544	3.8371	3.9293	3.0945
3.8575	4.0503	3.9319	3.2097
4.0604	4.2635	4.4255	3.3207
4.2621	4.4752	4.4270	3.4272
4.4610	4.6840	4.4293	3.5291
4.6560	4.8888	4.4325	3.6261

TIME V POPULATION, POWER SUPPLIES, POWER COST AND POWER DEMAND

PLOT FOR THE REGION 1



P = POPULATION S = POWER PRODUCED C = POWER COST D = POWER DEMAND

SELECTED WATER RESOURCES ABSTRACTS

INPUT TRANSACTION FORM

1. Report No.	2.	3. Accession No. W
4. Title Analysis of Engineering Alternatives for Environmental Protection from Thermal Discharges		5. Report Date
		6.
		8. Performing Organization Report No.
7. Author(s) Mar, B.W., Crutchfield, J.A., Welch, E.B., Bell, M.C., Geitner, N.M., Bush, R.M., Meyer, T., Porter, R., Saad, A.H.		10. Project No. 16130 FLM
9. Organization State of Washington Water Research Center, University of Washington/Washington State University, Pullman, Washington 99163		11. Contract/Grant No.
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15. Supplementary Notes

Environmental Protection Agency report number, EPA-R2-73-161, March 1973.

16. Abstract

A decision tree framework was utilized to integrate engineering decisions concerned with the control of environmental impacts from stationary thermal power plants. The engineering costs and the ecological response of fish communities to any sequence of decisions in the tree can be computed with the models developed in this study. A series of formulations were also developed to describe the environmental impact of siting a series of power plants in a region. Both the static and dynamic models require verification before they are applied. Impacts of thermal and chemical discharges to the receiving waters and mechanical damage from screening devices are modeled.

17a. Descriptors

Thermal Powerplants
Mathematical Models
Decision Trees
Intake Systems for thermal plants
Water Temperature
Thermal Effects
Socio-economic aspects of power generation
Cooling system chemicals for thermal power plants

17b. Identifiers

Thermal Power Plants, Thermal effects, Socio-economic effects, intake systems, chemical system, single plant assessment, dynamic assessment

17c. COWRR Field & Group

18. Availability	19. Security Class. (Report)	21. No. of Pages	Send To:
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Abstractor B. W. Mar | Institution University of Washington