final

NUREG-0176

# environmental statement

related to construction of

# BLACK FOX STATION UNITS 1 AND 2

## PUBLIC SERVICE COMPANY OF OKLAHOMA

FEBRUARY 1977

Docket Nos. STN 50-556
STN 50-557







U. S. Nuclear Regulatory Commission • Office of Nuclear Reactor Regulation

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NUREG-0176
February 1977

# FINAL ENVIRONMENTAL STATEMENT

by the

U. S. NUCLEAR REGULATORY COMMISSION

FOR

BLACK FOX STATION, UNITS 1 and 2

proposed by

PUBLIC SERVICE COMPANY OF OKLAHOMA

Docket Nos. STN 50-556 and STN 50-557

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SUMMARY AND CONCLUSIONS

This Environmental Statement was prepared by the U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation.

1. This action is administrative.

2. The proposed action is the issuance of construction permits to the Public Service Company of Oklahoma for the construction of the Black Fox Station, Units 1 and 2, Docket Nos. 50-556 and 50-557.

The Black Fox Station, located on the Verdigris River in Rogers County, Oklahoma, will employ two boiling water reactors producing up to 3579 megawatts thermal (MWt) per unit. Steam turbine-generators will use this heat to provide up to 1220 MWe of electrical power capacity per unit. The exhaust steam will be cooled by a condenser, and the waste heat will be dissipated to the atmosphere by round, mechanical-draft cooling towers.

3. Summary of environmental impacts and adverse environmental effects:

Attendant with the furnishing of electrical energy and with the benefits to be derived therefrom, the proposed plant will cause certain adverse environmental effects. The most significant of these effects are listed below.

a. Preparation of the central complex of the 2206-acre site will involve the disturbance of 466 acres of land, of which approximately half will be permanently devoted to station facilities, including water storage and holding ponds. Also to be disturbed are approximately 125 acres at the intake and discharge areas, a barge slip, and a drainage grading area between the central complex and the wastewater holding pond; however, only about four of these acres will be committed for the lifetime of the station.

b. Soil disturbance during construction of the station and transmission lines will tend to promote erosion and increase siltation in the Verdigris River and other water courses. Stringent measures will be taken to minimize those effects (Sec. 4.5).

c. Station and transmission line construction will kill, remove, and displace or otherwise disturb involved flora and fauna, and will eliminate varying amounts of wildlife breeding, nesting, and forage habitat. These will not be important, permanent impacts to the population structure and stability of the involved local ecosystems; however, measures will be taken to minimize such effects as do result from the proposed action (Sec. 4.5).

d. Approximately 2206 acres of grazing land on the site proper will be temporarily taken out of cattle production, and cattle on approximately 2400 acres of grazing land along the transmission corridors will be temporarily displaced. Crop production will be lost for one season on approximately 460 acres of agricultural land along the transmission corridors. After construction, less than 170 acres along the corridors will be removed from agricultural production (cropland and pastureland combined) for the lifetime of the station.

e. Previously undiscovered archeological resources are likely to be encountered along the transmission corridors. Measures will be taken to locate and protect such resources if they exist (Sec. 4.5).

f. Construction of the intake and discharge structures and of the barge slip will temporarily influence navigation on the Verdigris River to a minor extent. Such construction will also adversely affect benthic organisms in the near vicinity of the activity, but recolonization will occur after construction ceases.

g. Up to 39,100 acre-feet per year of Verdigris River water could be evaporated for station cooling; however, sufficient water exists in the river system to supply this demand without serious consequences, up to a "once-in-50-years" drought condition.

h. No significant environmental impacts are anticipated from normal operational releases of radioactive materials. The calculated dose to the estimated year 2000 population living within a 50-mile radius of the plant is less than 10 manrem/yr. This value is less than the natural fluctuations in the approximately 110,000 manrems/yr dose this population would receive from background radiation (Sec. 5.4). The risk associated with accidental radiation exposure will be very low (Sec. 7).

i. Station construction and operation are likely to cause some community impacts: influx of large numbers of construction workers may cause some impact on the Tulsa-Inola area housing market and schools, depending on the pattern of worker relocation; however, available housing units and classroom space will tend to decrease the impacts. The relatively small, permanent station work force will be absorbed with little difficulty (Secs. 4.4 and 5.9). An increase in local traffic will occur during construction; however, the relative remoteness of the site and the adequacy of the road system will minimize the impact (Sec. 4). A decrease in scenic value will result from the location of the station (and its associated transmission system) against the rural surroundings. Sensible (i.e., visual) air quality is also likely to decrease in the immediate vicinity of the station due to operation of the cooling tower system, but not to a great extent (Sec. 5).

4. Principal alternatives considered:

a. Alternative sites

b. Alternative energy sources

c. Purchase of power

d. Alternative heat-dissipation methods

5. The following Federal, State, and local agencies have been asked to comment on this Environmental Statement:

- Advisory Council on Historic Preservation
- Department of Agriculture
- Department of the Army, Corps of Engineers
- Department of Commerce
- Department of Health, Education and Welfare
- Department of Housing and Urban Development
- Department of the Interior
- Department of Transportation
- Energy Research and Development Administration
- Environmental Protection Agency
- Federal Power Commission
- Federal Energy Administration
- Office of the Governor of Oklahoma
- Mayor of Inola

6. This Environmental Statement was made available to the public, to the Council on Environmental Quality, and to other specified agencies in July 1976.

7. On the basis of the analysis and evaluation set forth in this Statement, after weighing the environmental, economic, technical, and other benefits of BFS, Units 1 and 2, against environmental and other costs and considering available alternatives, it is concluded that the action called for under the National Environmental Policy Act of 1969 (NEPA) and 10 CFR 51 is the issuance of construction permits for the facility, subject to the following conditions for the protection of the environment:

a. The applicant shall take the necessary mitigating actions, including adherence to his commitments summarized in Section 4.5.1, and additional staff requirements summarized in Section 4.5.2 of this Environmental Statement, during construction of the station and associated transmission lines to avoid unnecessary adverse environmental impacts from construction activities.

b. The applicant shall establish a control program which shall include written procedures and instructions to control all construction activities as prescribed herein and shall provide for periodic management audits to determine the adequacy of implementation of environmental conditions. The applicant shall maintain sufficient records to furnish evidence of compliance with all the environmental conditions herein.

c. Before engaging in a construction activity not evaluated by the Commission, the applicant will prepare and record an environmental evaluation of such activity. When the evaluation indicates that such activity may result in a significant adverse environmental impact that was not evaluated, or that is significantly greater than that evaluated in this Environmental Statement, the applicant shall provide a written evaluation of such activities and obtain prior approval of the Director of Nuclear Reactor Regulation for the activities.

d. If unexpected harmful effects or evidence of serious environmental damage are detected during facility construction, the applicant shall provide to the staff an acceptable analysis of the problem and a plan of action to eliminate or significantly reduce the harmful effects or damage.

e. The applicant shall submit for staff approval, prior to issuance of construction permits, the routing and design of the water transport from the intake structure to the presettling pond.

f. In addition to the monitoring procedures described in the Environmental Report, with amendments, the staff requirements included in Section 6 of this document shall be followed.

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## FOREWORD

This environmental statement was prepared by the Division of Site Safety and Environmental Analysis, Office of Nuclear Reactor Regulation, the U. S. Nuclear Regulatory Commission (the staff), in accordance with the Commission's regulation 10 CFR Part 51, which implements the requirements of the National Environmental Policy Act of 1969 (NEPA).

The NEPA states, among other things, that it is the continuing responsibility of the Federal Goverment to use all practicable means, consistent with other essential considerations of national policy, to improve and coordinate Federal plans, functions, programs, and resources to the end that the Nation may:

- Fulfill the responsibilities of each generation as trustee of the environment for succeeding generations.
- Ensure for all Americans safe, healthful, productive, and esthetically and culturally pleasing surroundings.
- Attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable and unintended consequences.
- Preserve important historic, cultural, and natural aspects of our national heritage, and maintain, wherever possible, an environment which supports diversity and variety of individual choice.
- Achieve a balance between population and resource use which will permit high standards of living and a wide sharing of life's amenities.
- Enhance the quality of renewable resources and approach the maximum attainable recycling of depletable resources.

Further, with respect to major Federal actions significantly affecting the quality of the human environment, Section 102(2)(C) of the NEPA calls for preparation of a detailed statement on:

(i) the environmental impact of the proposed action,

(ii) any adverse environmental effects which cannot be avoided should the proposal be implemented,

(iii) alternatives to the proposed action,

(iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and

(v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented.

An environmental report accompanies each application for a construction permit or a full-power operating license for a nuclear power generating station. A public announcement of the availability of the report is made. Any comments on the report by interested persons are considered by the staff. In conducting the required NEPA review, the staff meets with the applicant to discuss items of information in the environmental report, to seek new information from the applicant that might be needed for an adequate assessment, and generally to ensure that the staff has a thorough understanding of the proposed project. In addition, the staff seeks information from other sources that will assist in the evaluation, and visits and inspects the project site and surrounding vicinity. Members of the staff may meet with State and local officials who are charged with protecting State and local interests. On the basis of all the foregoing and other such activities or inquiries as are deemed useful and appropriate, the staff makes an independent assessment of the considerations specified in Section 102(2)(C) of the NEPA and in 10 CFR 51.

This evaluation leads to the publication of a Draft Environmental Statement, prepared by the Office of Nuclear Reactor Regulation, which is then circulated to Federal, State, and local governmental agencies for comment. This Statement is organized in such a way that Sections 1, 2, and 3 are primarily descriptive in nature; the results of the staff's review and evaluation are contained in subsequent sections. A summary notice is published in the Federal Register of the availability of the applicant's environmental report and the Draft Environmental Statement. Interested persons are also invited to comment on the Draft Statement. Comments should be addressed to the Director, Division of Site Safety and Environmental Analysis, at the address shown below.

In response to Memoranda of Understanding[1,2] which govern certain interactions of the U. S. Nuclear Regulatory Commission with the U. S. Environmental Protection Agency and the U. S. Army Corps of Engineers, the staff has submitted to those agencies, and received comments thereon, Statements of Positions[3,4] which previewed interim staff conclusions and positions of environmental matters of mutual interest. The staff has considered these comments during the preparation of this Environmental Statement. While exclusive jurisdiction resides in the U. S. Environmental Protection Agency (EPA) to regulate non-radiological effluents (and it will do so via its NPDES permit when issued), the NRC is required to assess the environmental impact of permitted discharges. In the spirit of cooperation set forth in the NRC-EPA Second Memorandum of Understanding, the staff will aid the U. S. EPA in the selection of permissible levels of discharges by sharing information developed during this environmental assessment.

After receipt and consideration of comments on the Draft Statement, the staff prepares a Final Environmental Statement, which includes: a discussion of concerns raised by the comments; a benefit-cost analysis, which considers the environmental costs of the plant and the alternatives available for reducing or avoiding them, and balances the adverse effects against the environmental, economic, technical, and other benefits of the plant; and a conclusion as to whether the action called for, with respect to environmental issues, is the issuance of the proposed permit, with appropriate conditioning to protect environmental values, or its denial. The Final Environmental Statement and the Safety Evaluation Report prepared by the staff are submitted to the Atomic Safety and Licensing Board for its consideration in reaching a decision on the application.

Single copies of this Statement may be obtained by writing the:

Director, Division of Site Safety and Environmental Analysis
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Mr. Jan A. Norris is the NRC Environmental Project Manager for this project. Should there be questions regarding the content of this Statement, he may be contacted at the above address or at 301/443-6990.

References


1. "Second Memorandum of Understanding regarding Implementation of Certain NRC Positions and Responsibilities," January 30, 1976.

2. "Memorandum of Understanding between Corps of Engineers, United States Army, and the United States Regulatory Commission for Regulation of Nuclear Power Plants," July 2, 1975.

3. Statement of Positions for U.S.E.P.A., February 27, 1976.

4. Statement of Positions for U. S. Army Corps of Engineers, February 27, 1976.

# 1. INTRODUCTION

## 1.1 THE PROPOSED PROJECT

Pursuant to the Atomic Energy Act of 1954, as amended, and the Commission's regulations in Title 10, Code of Federal Regulations, an application was filed by the Public Service Company of Oklahoma (PSO) (hereafter referred to as the applicant) for Construction Permits for two boiling-water nuclear reactors designated as the Black Fox Station (BFS), Units 1 and 2 (Docket Nos. STN 50-556 and STN 50-557) each of which is designed for a rated core power of 3579 megawatts thermal (MWt), with a gross electrical output of approximately 1220 megawatts electrical (MWe). Dissipation of waste heat will be accomplished by circular mechanical-draft cooling towers, three per reactor unit. The Verdigris River navigation channel will be the sole source of cooling water. The proposed facilities are to be located on the applicant's site in Rogers County, Oklahoma, approximately three miles from the Inola business district, and approximately 12 miles east of the Tulsa city limits.

Title 10 CFR Part 51 requires that the Director of Nuclear Reactor Regulation, or his designee, analyze the applicant's Environmental Report and prepare a detailed statement of environmental considerations. It is within this framework that this Environmental Statement related to the construction of the Black Fox Station has been prepared by the Division of Site Safety and Environmental Analysis (staff) of the U. S. Nuclear Regulatory Commission.

Major documents used in the preparation of this statement were the applicant's Preliminary Safety Analysis Report (PSAR),* and the Environmental Report (ER)** and supplements thereto, issued for BFS. Independent calculations and sources of information were also used by the staff and serve as a basis for the assessment of environmental impact. Additional information was gained from visits by the staff to the BFS site, to alternative sites, and to surrounding areas during 1975 and 1976.

As a part of its safety evaluation leading to the issuance of construction permits and operating licenses, the Commission makes a detailed evaluation of the applicant's plans and proposed facilities for minimizing and controlling the release of radioactive materials under both normal conditions and potential accident conditions, including the effects of natural phenomena on the facility. Inasmuch as these aspects are considered fully in other documents, only the salient features that bear directly on the anticipated environmental effects are considered in this Environmental Statement.

Copies of this Environmental Statement and the applicant's ER and PSAR are available for public inspection at the Commission's Public Document Room, 1717 H Street, N. W., Washington, D. C., and the Tulsa City-County Library, Tulsa, Oklahoma.

## 1.2 STATUS OF REVIEWS AND APPROVALS

To construct the BFS and certain related facilities, the applicant is required to apply for and receive certain permits, licenses, and other authorizations from a number of Federal, State, and local agencies. These permits and licenses are listed in Table 12.1-1 of the ER. The applicant must also obtain transmission line right-of-way permits for railroad, road, and highway crossings. Reviews for such permits are also noted in Table 12.1-1 of the ER. A staff review of the environmental aspects of the transmission lines and their rights-of-way is included in this Environmental Statement.

The applicant will be required to meet all Federal, State, and local water quality and effluent discharge limits as specified in operating permits.

*"Public Service Company of Oklahoma, Black Fox Station Units 1 and 2, Preliminary Safety Analysis Report," with amendments, Docket Nos. STN 50-556 and STN 50-557, December 1975, hereinafter referred to as the PSAR.

**"Public Service Company of Oklahoma, Black Fox Station Units 1 and 2, Environmental Report," with amendments, Docket Nos. STN 50-556 and STN 50-557, December 1975, hereinafter referred to as the ER, and usually accompanied by reference to a specific section, page, figure, table or appendix number (for example, ER, Sec. 5.4).

# 2. THE SITE AND ENVIRONS

## 2.1 LOCATION

The proposed 2206-acre BFS site is in Inola Township, Rogers County, Oklahoma, 12 miles east of Tulsa city limits. Part of the site is within the corporate limits of Inola, Oklahoma. Inola's central business and residential district is about three miles northeast of the proposed reactor sites.

The coordinates of the point midway between the reactor centers of Units 1 and 2 are 36° 7' 1" North Latitude and 95° 32' 54" West Longitude. Figure 2.1 shows the regional location of the BFS site, and Figure 2.2 shows the outline of the station boundary and the general layout of station facilities.

The Verdigris River forms the Rogers-Wagoner county line just west of the site. The western boundary of the site is along a portion of the eastern edge of a 300-foot-wide strip of U. S. Government property on the east bank of the Verdigris River. This land is maintained by the U. S. Army Corps of Engineers as part of the McClellan-Kerr Arkansas River Navigation System. It is proposed that the station's river intake, discharge, and barge slip facilities be located on this U. S. Government property.

The Left Abutment Access Road to Newt Graham Lock and Dam No. 18 passes within one-half mile of the eastern site boundary. Oklahoma State Highway 33 is about two miles north of the boundary. The closest railroad mainline approach is 2-1/4 miles northeast of the boundary.

## 2.2 LAND USE

Public Service Company of Oklahoma has acquired 2206 acres of land for the BFS site, as shown in Figure 2.3. Seventy percent of the site is on relatively flat land at 650-680 feet MSL. At the present time, shown in Table 2.1, about three-fourths of the site is solely devoted to pastureland, and the rest to woodland and haymeadows. No commercial or industrial use is made of the land. Pasturing is the main use of the site itself. This is especially true since cattle graze the woodlands as well as the pasture. Cattle production is a major regional industry. According to the U. S. Department of Agriculture Marketing Service (Oklahoma City), in 1972 the 11-county Northeastern District of Oklahoma produced 829,000 cattle and calves with a 1976 value of $160 per head, or a total value of $132,640,000. If committed to stock production the BFS site could produce 300 calves per year (ER, Supp. 0) from the parent herd. The calves would wean at 400 pounds, and at $160 per head would yield an annual revenue of $48,000.

Table 2.1. Present Land Use of the BFS Site

| Land Use | Acres or Number[a] | Percent |
|---|---|---|
| Extractive (number) | | |
| Oil wells | (3) | NA[b] |
| Gas wells | (2) | NA |
| Residential (number) | (10) | NA |
| Pasture, acres | 1587 | 72 |
| Woodland, acres | 330 | 15 |
| Hay, acres | 220 | 10 |
| Ponds, acres | 30 | 1 |
| Roads, acres | 24 | 1 |
| Other, acres | 22 | 1 |

[a]Total area is 2206 acres

[b]NA = information not available

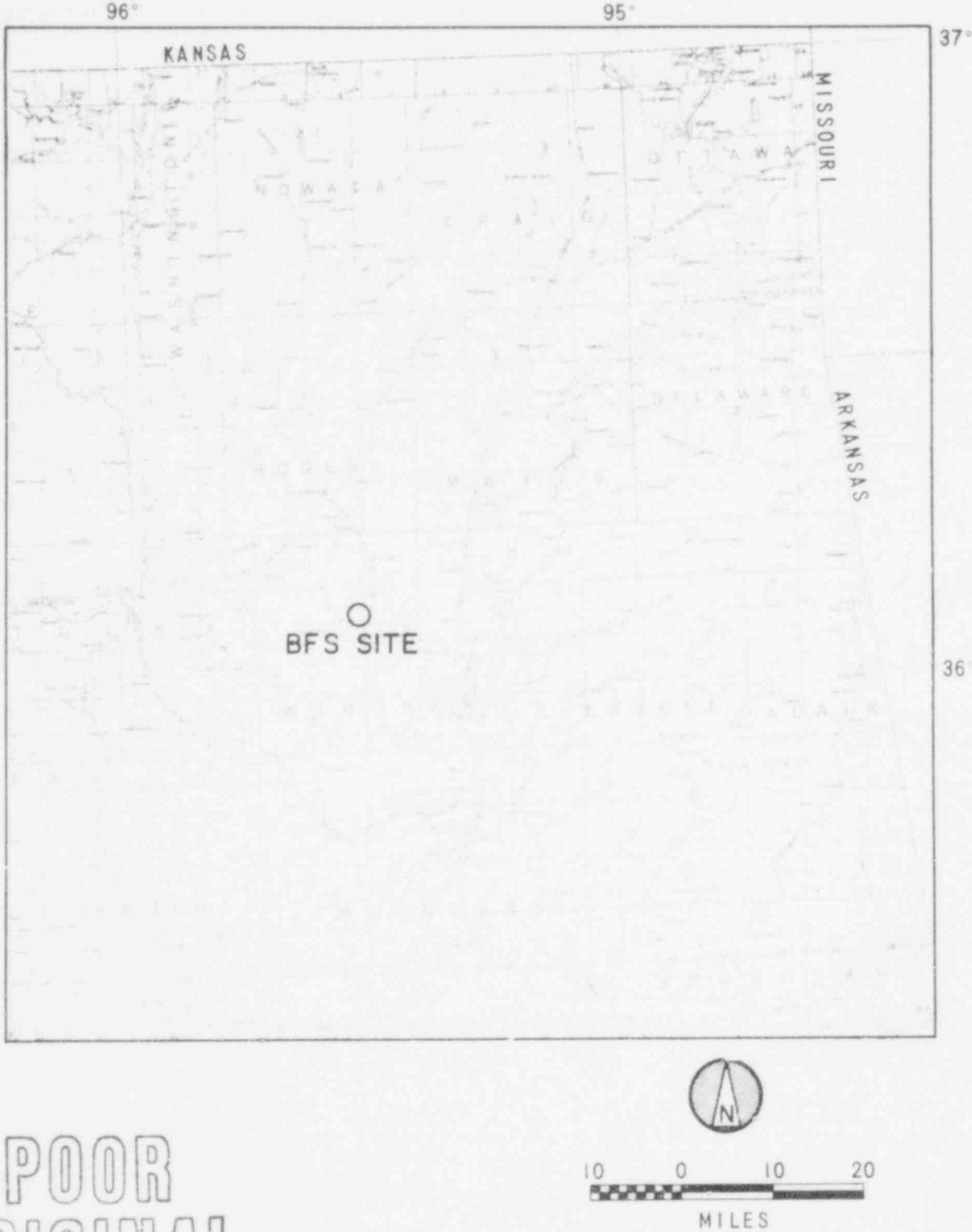




Fig. 2.1. Site Location. From PSAR, Fig. 2.5-1.

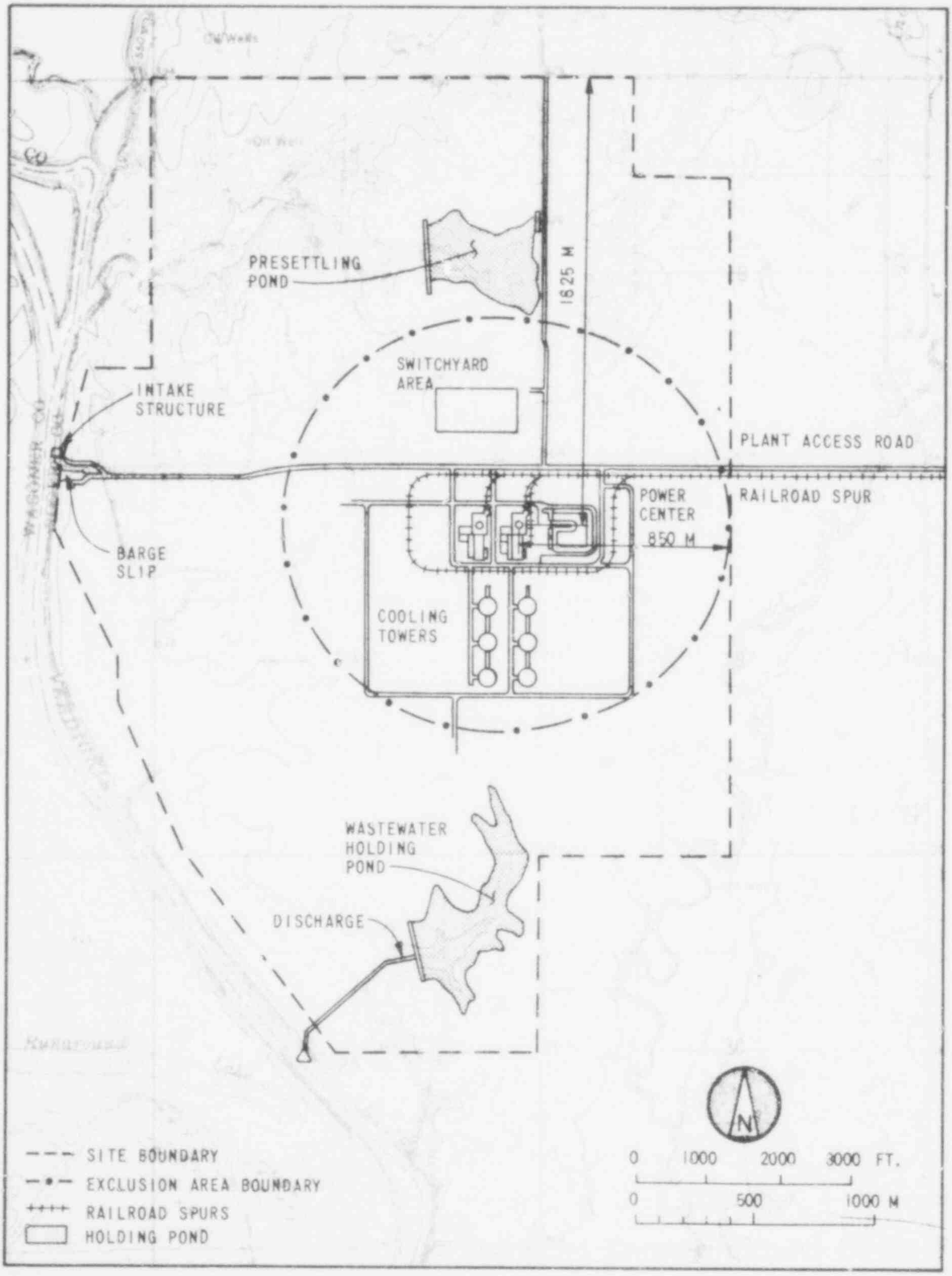


Fig. 2.2. Black Fox Plant Arrangement. From ER, Fig. 2.1-3.

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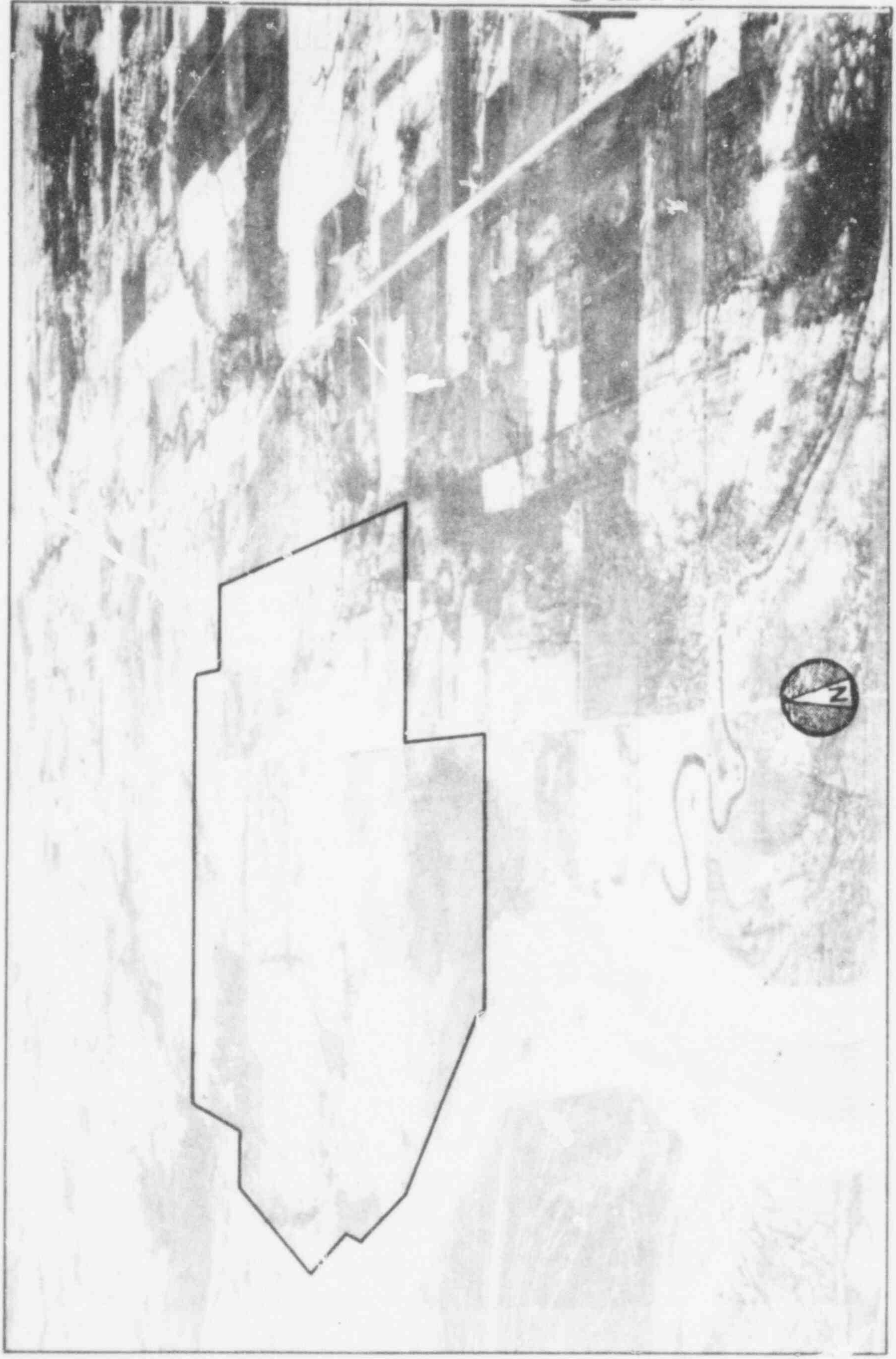

Fig. 2.3. Oblique Aerial View of Proposed BFS Site. From ER, Fig 3.1-1.

Onsite there are three oil wells (two abandoned and one that produced half a barrel per day in 1974) and two productive gas wells (flow of about 75 mcf/day), one providing gas to a house and the other to a ranch. There is some coal on the site, but because the seams under the site are thin, lenticular, and covered by considerable overburden, they are not economically exploitable, either by surface or deep mining.

A field survey by the applicant indicated that land use within five miles of the site included pastureland (46%), crops (19%), hay (18%), woodland (12%), and other uses (5%). Present and future land use within five miles of the site is shown in Figures 2.4 and 2.5, respectively. From 1958 to 1967, cropland in Rogers County decreased 40%, while pastureland and urban and built-up areas increased 35% and 36%, respectively (ER, p. 2.1-6).

There are three schools and nine churches within five miles of BFS, with the nearest school being 3 1/2 miles from the site. ' Inola, the nearest residential community, land use distribution is: residential, 44%; commercial, 1%; industrial, 1%; public and quasi-public, 12%; streets and railroads, 28%; agriculture and vacant land, 14%.

Nine of 25 proposed or existing public use areas along the Arkansas and Verdigris Rivers between Webbers Falls and Catoosa are within five miles of the site. Newt Graham Lock and Dam observation area, Bluegill Point, Channel View No. 2, and Highway 33 Landing Public Use Area were in operation throughout 1974. About 40% of the use of these facilities that year was for boating and fishing, and 40% was for sightseeing, with 20% being devoted to other uses.

## 2.3 WATER USE

The proposed BFS site is in the Verdigris River Basin 38.5 miles above the confluence of the Verdigris and Arkansas Rivers. The primary uses of the Arkansas River downstream of the Verdigris are navigation, hydroelectric power generation, and flood control. The uses of the Verdigris River in the site vicinity include navigation, water supply, irrigation, and recreation.[1] The water quality of the Arkansas is poor as a public water supply and for irrigation. The Verdigris River is of somewhat higher quality.

The State of Oklahoma controls water allocations. As of August 1974, 69 surface water permits were issued by the Oklahoma Water Resources Board for Rogers and Wagoner Counties for annual allocations of 491,630 acre-feet (673 cfs; approximately one-third of the average flow of the Verdigris River). This included, however, rivers, reservoirs, and lakes outside of the Verdigris drainage basin.[2]

As of June 1976, water storage allocations in the Oologah reservoir and estimated yield are as follows:

| User | Contracted Storage | Maximum Yield (MGD) | Dependable Yield (MGD) |
|---|---|---|---|
| City of Tulsa | 313,500 acre-feet | 202 | 141 |
| Public Service Company of Oklahoma | 21,600 acre-feet | 19 | 13 |
| City of Collinsville | 5,500 acre-feet | 4 | 2.8 |
| Rural Water District No. 1, Nowata County | 200 acre-feet | .12 | .08 |
| Rural Water District No. 1, Rogers County | 200 acre-feet | .12 | .08 |
| Rural Water District No. 3, Rogers County | 1,000 acre-feet | .64 | .45 |
| Rural Water District No. 4, Rogers County | 600 acre-feet | .39 | .27 |
| Navigation Storage | 168,000 acre-feet | 108 | 75 |
| Total | 510,600 acre-feet | 336 | 235 |

The total dependable yield of the reservoir is completely allocated. The City of Tulsa presently uses no water from Oologah, however, beginning in mid-1977 approximately 20 MGD of Oologah water will be pumped to Tulsa.* By the year 2000, the projected use of Tulsa's allocation (141 MGD) is estimated to be approximately 51 MGD.* This leaves about 90 MGD available in storage. It is this unused water that the applicant is seeking to acquire. At the publication time of this statement, a water rights contract agreement between the City of Tulsa and the applicant has not been drafted in final form.

*Telephone communication, Charles L. Kimberling, City of Tulsa, Water and Sewer Department, December 20, 1976.

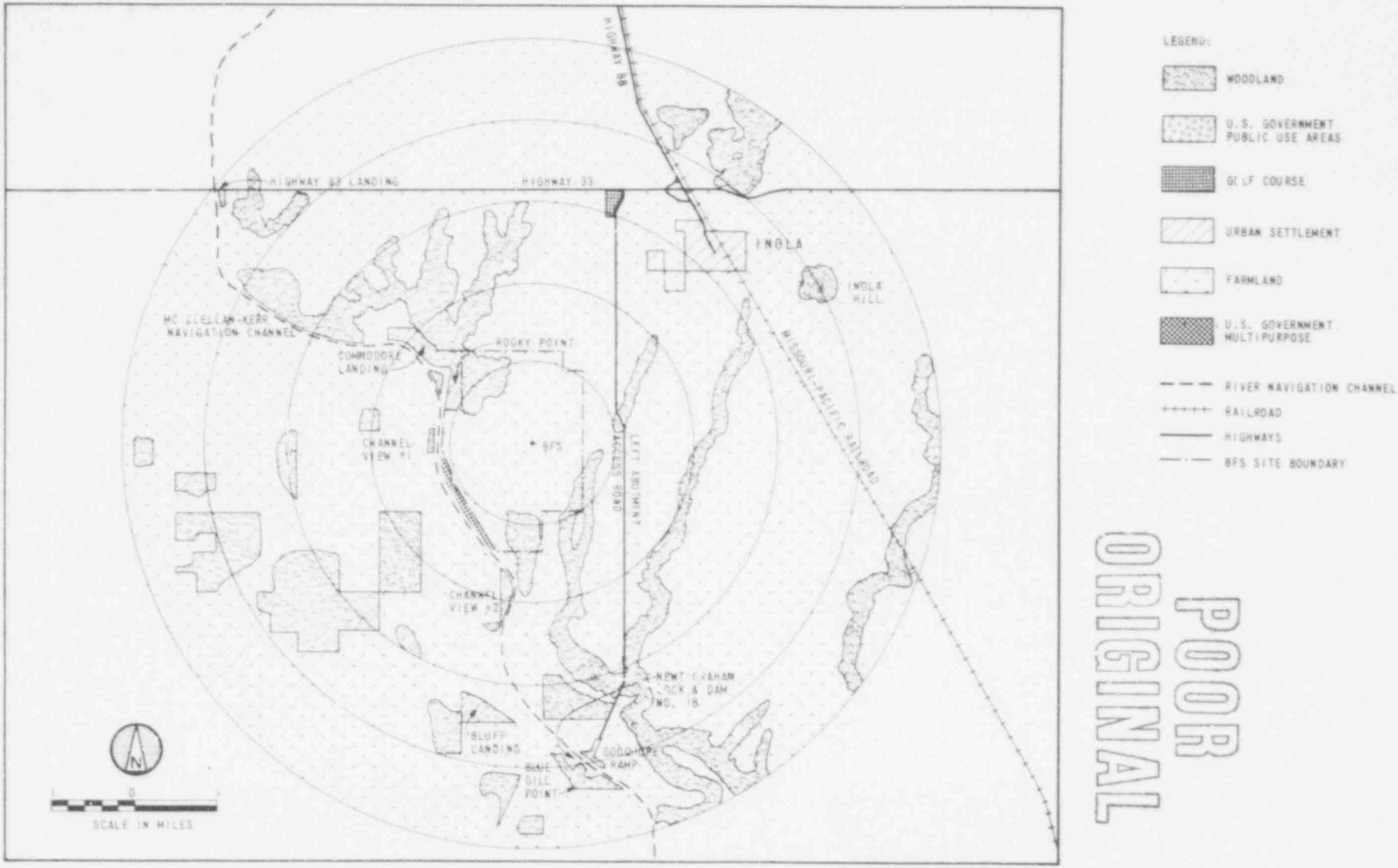


Fig. 2.4. Existing Land Use within Five Miles of BFS. From ER, Fig. 2.1-12.

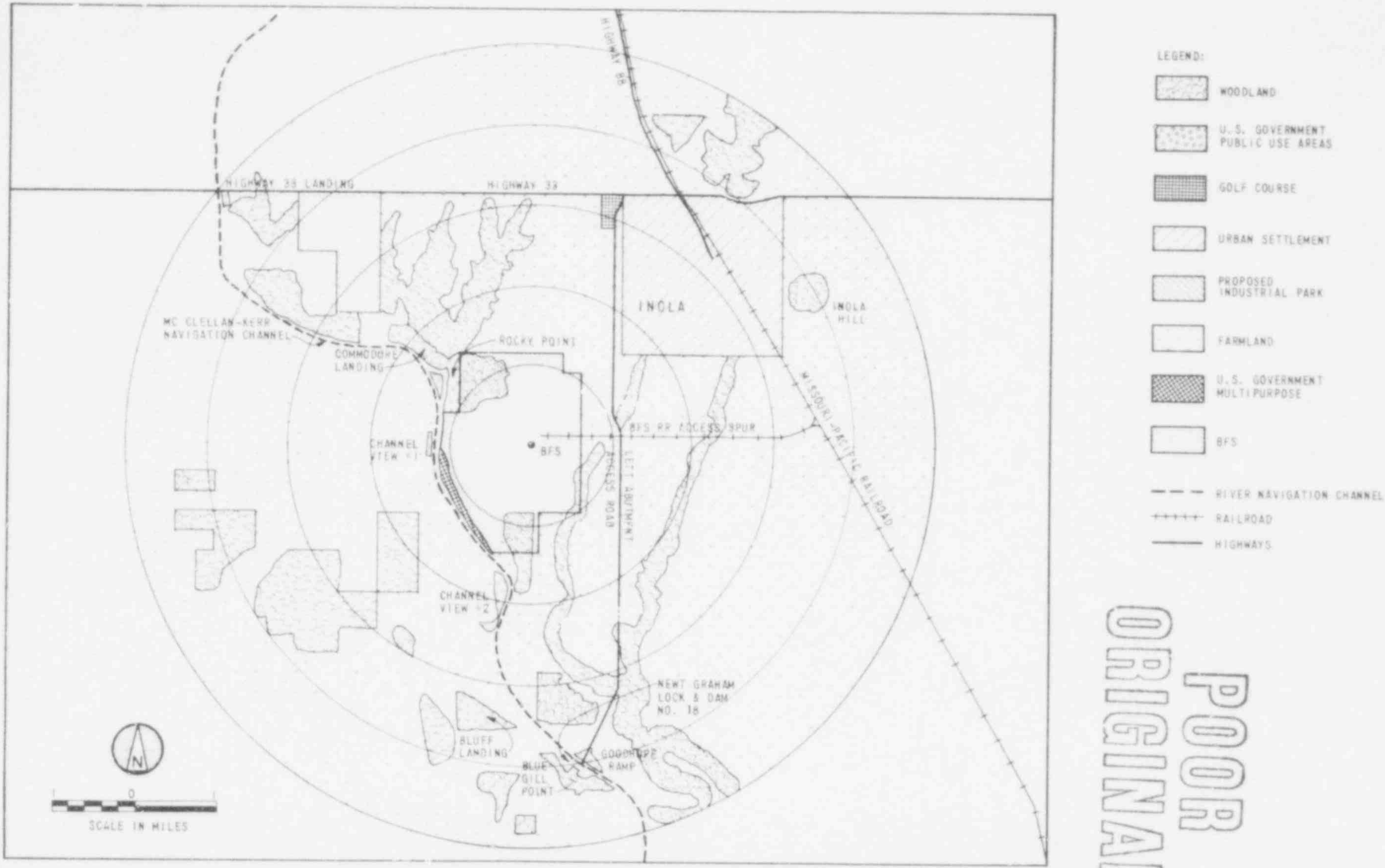


Fig. 2.5. Future Land Use within Five Miles of BFS. From ER, Fig. 2.1-13.

### 2.3.1 Municipal and Industrial

There are three municipal water supply system intakes on the Verdigris River downstream of the BFS site, at Broken Arrow, Coweta, and Okay, Oklahoma. They also supply treated water to rural water districts. The areas served are shown in Figure 2.6. Presently these three systems hold water rights applications for 18,995 acre-feet (26 cfs) (ER, Sec. 2.1.4.2). Total municipal and industrial water use in Rogers and Wagoner Counties in 1969 was about 7000 acre-feet (10 cfs).[1] Table 2.2 lists the users of Verdigris River water and quantities of water applied for.

### 2.3.2 Irrigation

There are irrigated lands along the Verdigris River between the site vicinity and the confluence with the Arkansas River. Applications for water rights in this stretch of the river total 3514 acre-feet (4.8 cfs) (ER, Sec. 2.1.4.2). Figure 2.7 shows the location of irrigation and other water-users along the Verdigris. In 1969 the quantity of water used for irrigation (from all surface sources) in Rogers and Wagoner Counties was about 1900 acre-feet (2.6 cfs).[1]

### 2.3.3 Navigation

The Verdigris River from the head of navigation, Port of Catoosa, to its confluence with the Arkansas River near Muskogee, Oklahoma, is part of the McClellan-Kerr Arkansas River Navigation System. The development of the Arkansas River and its tributaries for navigation, flood control, hydroelectric power, and other purposes is the largest civil works project ever undertaken by the public and the U. S. Army Corps of Engineers. It connects central Oklahoma with the Gulf of Mexico. The McClellan-Kerr Arkansas River Navigation System has a minimum navigation depth of nine feet, with a minimum width of 250 feet provided on the Arkansas River; the Verdigris River channel was constructed 150 feet wide, but was designed for future widening to 250 feet. The locks are 110 feet wide by 600 feet long and can accommodate a tow boat and up to eight 35-by-195-foot barges in each lockage. Three locks and dams are located in northeastern Oklahoma: Webbers Falls Lock and Dam on the Arkansas River and Chouteau Lock and Dam and Newt Graham Lock and Dam on the Verdigris River. The waterway includes a turning basin at its terminus near Catoosa.

On July 24, 1946, President Harry S Truman signed the River and Harbor Act, which authorized the project for development of the Arkansas River and tributaries for navigation, flood control, hydroelectric power, and other purposes. Construction was started in 1956 and the waterway was opened for its full length in 1970. The overall project was completed in 1972. Ten lakes compliment the McClellan-Kerr Arkansas River Navigation System. Each has multiple-purpose functions, including necessary flood control. Oologah Lake is the only project which stores water for lock operation.

In the Verdigris River portion of the navigation system there are two locks and dams for controlling water levels in long, slack water pools for commercial and recreational traffic using the system. Newt Graham Lock and Dam, about four miles downstream of the site, is the last major controlling structure on the navigation system. It has a lift of 21 feet and provides about 25 miles of navigable pool to the Port of Catoosa. In 1973 the entire navigation system carried 800,000 tons of traffic.[2] Approximately 560 barge tows utilized the Newt Graham Lock and Dam in 1974, and Corps projections of future use (ER, Table 2.1-14), in the staff's opinion, are optimistic--6800 tows in the year 2000 (ER, Sec. 2.1.4.2).

### 2.3.4 Hydroelectric Power

The only hydroelectric power installation on the McClellan-Kerr Arkansas River Navigation System in the near region of the site is about 55 miles downstream of Newt Graham Lock and Dam at Webers Falls Lock and Dam* (60,000 kW)[1] Oologah Dam (about 47 river miles upstream of the site) originally had provision for future hydorelectric generation. However, power as a project purpose was deauthorized by Section 97 of the Water Resources Development Act, Public Law 93-251 dated 7 March, 1974.

### 2.3.5 Recreation

The entire McClellan-Kerr Arkansas River Navigation System is open to pleasure craft. Recreational activities along the Verdigris River include boating, fishing, picnicking, sightseeing (vista views and areas for observing lock and dam operations), and other activities (see Table 2.3).

*The owner-constructor of the Webbers Falls installation is the U.S. Army Corps of Engineers; however, the Southwestern Power Administration markets the power.

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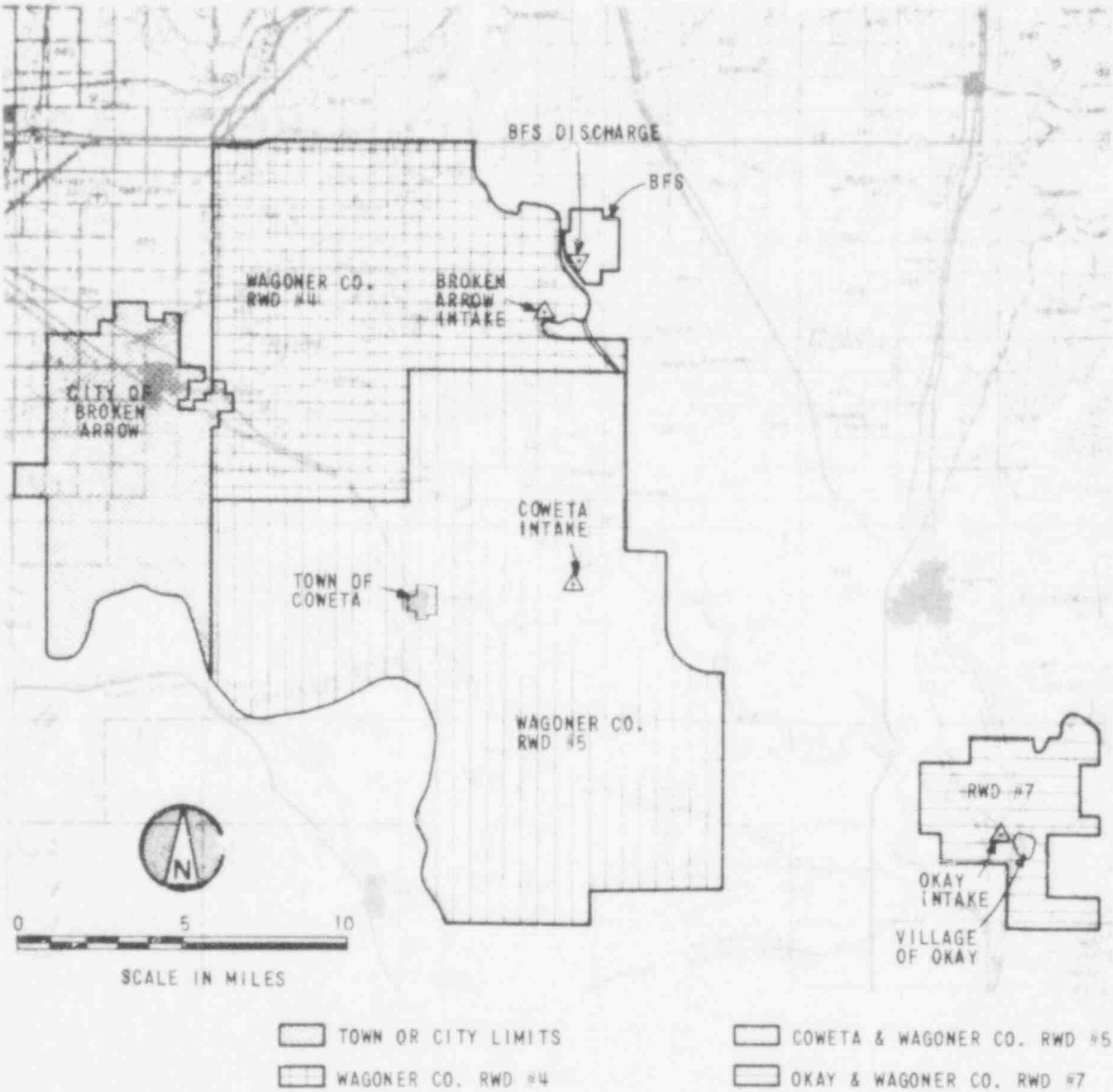


Fig. 2.6. Boundaries of Water Districts Using Verdigris River as Source of Supply. From ER, Fig. 2.1-29.

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Table 2.2. Users of River Water from the Verdigris River, Downstream of the BFS Site.

| | User | Township-Range | Use | Quan. Appl. for, acre-feet | Acres to Irrigate |
|---|---|---|---|---|---|
| | **To the Confluence with the Arkansas River** | | | | |
| 1. | J. Harley Galusha | N1/2, Sec 23, T19N, R 6E | Irrigation | 800 | 400 |
| 2. | H. S. Diem | E1/2, N[illegible]1/4, Sec 23, T19N, R16E | Irrigation | 100 | 50 (on proposed site) |
| 3. | City of Broken Arrow | N1/2, SW1/4, Sec 35, T19N, R16E | Industrial & Municipal | 16,680 | |
| 4. | Elbert M. Woodward | E1/2, SW1/4, Sec 6, T18N, R17E | Irrigation | 16 | 8 |
| 5. | Carl C. Anderson, Sr. | N1/2, SE1/4, Sec 30, T18N, R17E | Irrigation | 120 | 60 |
| 6. | Town of Coweta | S1/2, SW1/4, Sec 6, T17N, R17E | Municipal & Industrial | 2,240 | |
| 7. | Mrs. John H. Dunkin | SW1/4, Sec 8, T17N, R17E | Irrigation | 454 | 227 |
| 8. | Mrs. A. C. Benson | S1/2, SW1/4, Sec 15, T17N, R17E | Irrigation | 160 | 80 |
| 9. | Thomas R. Quigley | E1/2, Sec 27, T17N, R17E | Irrigation | 1,250 | 625 |
| 10. | W. S. Warner | E1/2, SE1/4, Sec 5, T16N, R18E | Irrigation | 184 | 92 (out of production) |
| 11. | Evelyn C. Wolcott | E1/2, NE1/4, Sec 5, T16N, R18E | Irrigation | 350 | 175 |
| 12. | Town of Okay | E1/2, NE1/4, Sec 19, T16N, R19E | Municipal | 75 | |
| 13. | George Lemons | S1/2, SE1/4, Sec 24, T16N, R18E | Irrigation | 80 | 40 (out of production) |
| | **On the Arkansas River below the Confluence of the Verdigris River, within the State of Oklahoma** | | | | |
| 14. | Earl J. Grant | S1/2, Sec 25, T15N, R19E | Irrigation | 774 | |
| 15. | Edsel Roberts | W1/2, Sec 11, T13N, R19E | Irrigation | 406 | |
| 16. | Jesse L. Kincannon & J. T. & Myrtle | SW1/4, NE1/4, Sec 18, T12N, R21E | Irrigation | 306 | |
| 17. | J. C. Alexander Jr. | SW1/4, SW1/4, Sec 20, T12N, R21E | Irrigation | 190 | |
| 18. | C. E. Sloan | SE1/4, Sec 29, T12N, R21E | Irrigation | 200 | |

From ER, Supp. 0, Table 2.1-13.


Fig. 2.7. Location of Applicants for Water Rights on Verdigris River. (Numbers refer to list in Table 2.2.) From ER, Supp. O, Fig. 2.1-30.



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Table 2.3. Ultimate Annual Number Visitor-Activities by Area

| Area | Activities | | | | | | | | Total |
|---|---|---|---|---|---|---|---|---|---|
| | Camping | Picnicking | Sightseeing | Boating | Fishing | Swimming | Skiing | Miscellaneous | |
| Lock & Dam 18 | 0 | 0 | 101,000 | 0 | 0 | 0 | 0 | 0 | 101,000 |
| Highway 33 | 3,000 | 9,000 | 45,000 | 53,000 | 13,000 | 5,000 | 6,000 | 4,000 | 138,000 |
| Goodhope | 1,500 | 3,000 | 11,500 | 26,000 | 3,000 | 0 | 3,000 | 500 | 48,500 |
| Bluegill | 1,500 | 6,000 | 22,500 | 9,000 | 13,000 | 4,000 | 1,000 | 1,500 | 58,500 |
| Bluff | 3,000 | 12,000 | 11,000 | 26,000 | 6,000 | 5,000 | 3,000 | 2,500 | 68,500 |
| Channel View | 0 | 12,000 | 11,000 | 9,000 | 10,000 | 7,000 | 1,000 | 1,500 | 51,500 |
| Rocky Point | 3,000 | 6,000 | 11,500 | 26,000 | 10,000 | 7,000 | 3,000 | 2,500 | 69,000 |
| Commodore | 3,000 | 12,000 | 11,500 | 26,000 | 10,000 | 7,000 | 3,000 | 2,500 | 75,000 |
| TOTAL | 15,000 | 60,000 | 225,000 | 175,000 | 65,000 | 35,000 | 20,000 | 15,000 | 610,000[a] |

[a]Although the ultimate number of visitors to the Verdigris River Public Use Areas is anticipated to be 400,000, it is assumed on the basis of actual use statistics that on the average each visitor would engage in about 1.5 activity types.

From ER, Table 2.1-15.

2.3.6 Groundwater

Limited amounts of groundwater are available in the site vicinity in alluvial and terrace deposits in and along stream valleys. Because of low yields, thin potable zones, and presence of salt water at shallow depths in regional aquifers, groundwater use is restricted, causing a relative dependence on surface water. Properly constructed wells in alluvium along the Verdigris or Arkansas Rivers can yield up to 100 gpm (Rogers County) and 500 gpm (Wagoner County).[3] Only one user of groundwater for irrigation has been identified in the near site region (Wagoner County). The application is for 1366 acre-feet (1.9 cfs) (ER, Sec. 2.1.4.2). The Oklahoma Water Resources Board controls groundwater uses in the State and issues use permits. No groundwater permits were in force as of August 1974 in Rogers County.[2] Locations of low-yield domestic wells within three miles of the site are shown on Figure 2.8.

2.4 GEOLOGY AND SEISMICITY

2.4.1 Geology

The region within 50 miles of the site includes portions of the Central Lowlands, the Ozark Plateau, and the Ouachita Physiographic Provinces. The BFS site is in the eastern part of the Osage Plains section of the Central Lowlands Province. This section is underlain primarily by westward-dipping Late Paleozoic sandstones, limestones, and shales and exhibits a low topographic profile. The more resistant sandstones support steep east-facing escarpments, and the valleys are formed over the weaker shales.

The land surface in the site vicinity is a gently rolling plain bounded on the north by a low southeast-facing escarpment. Local relief varies from 545 feet MSL at the Verdigris River floodplain west of the site to about 660 feet MSL on a ridge just north of the site. Topographic character is further influenced by four drainage elements wholly or partially on the site (see Sec. 2.5).

The site vicinity bedrock to depths of about 550 feet includes primarily Pennsylvanian cyclothem deposit of the Desmoinesian Series. Within the site boundary, the bluejacket sandstone forms bedrock. The McAlester Formation is the oldest rock unit exposed in the site vicinity, and it is overlain sequentially by the Savanna, Boggy, and Senora formations.

Figure 2.9 shows a stratigraphic column of the vicinity and includes a description of the rock units present.

Unconsolidated Quaternary terrace deposits, typically consisting of silty clay, but with some silt, sand, and chert gravel, are exposed in erosional remnant river terraces along the Verdigris River. These deposits occur at elevations as high as 600 feet and may be found with thicknesses up to 40 feet. The most recent deposits in the site vicinity consist of floodplain alluvium, residual soils, and colluvium. Recent alluvium, which consists of dark gray silt and clay, occupies the Verdigris River floodplain and the valley floors of most other streams. Residual soils mantle most of the bedrock with thicknesses up to five feet. The soils are usually thicker and more developed on shales than on sandstones.

2.4.2 Economic Geology

Oil and gas have been produced from several small pools in Rogers and Wagoner Counties near the site. The nearest producing horizons are the Pennsylvanian sandstones, Upper Mississippian limestones, and Middle Ordovician sandstone. Numerous small pools, each only a few acres in extent, were discovered in early exploration and have been abandoned. The largest defined producing area near the site, the Inola Field, is actually a cluster of several pools scattered around Inola. Production declined from 1930, and in recent years no production has been recorded. Available production records show only a small amount of gas and oil was produced in the site area. In 1972 and 1973 three dry holes and one oil well were drilled at the western site boundary near the proposed location of the barge slip and intake structure. The oil well had an initial production of only 36 barrels per day.

Rowe coal in the Savanna Formation is being open-pit mined about four miles southeast of the site. This coal seam occurs at depths of 125 to 250 feet beneath the surface. The seam varies from 0.4 to 2.3 feet in thickness. Another coal seam, the one-foot-thick Drywood Coal, is present at the site at depths from about 25 to 105 feet.

The Bluejacket sandstone member of the Boggy Formation is occasionally quarried at the northwestern corner of the site boundary. This sandstone is exposed along the bank of the Vergidris River within the site. According to the applicant, gravel deposits, primarily chert clasts, occur locally in the Quaternary terraces and occasionally in sufficient thicknesses to warrant exploitation; no economically exploitable gravels were found within the site.

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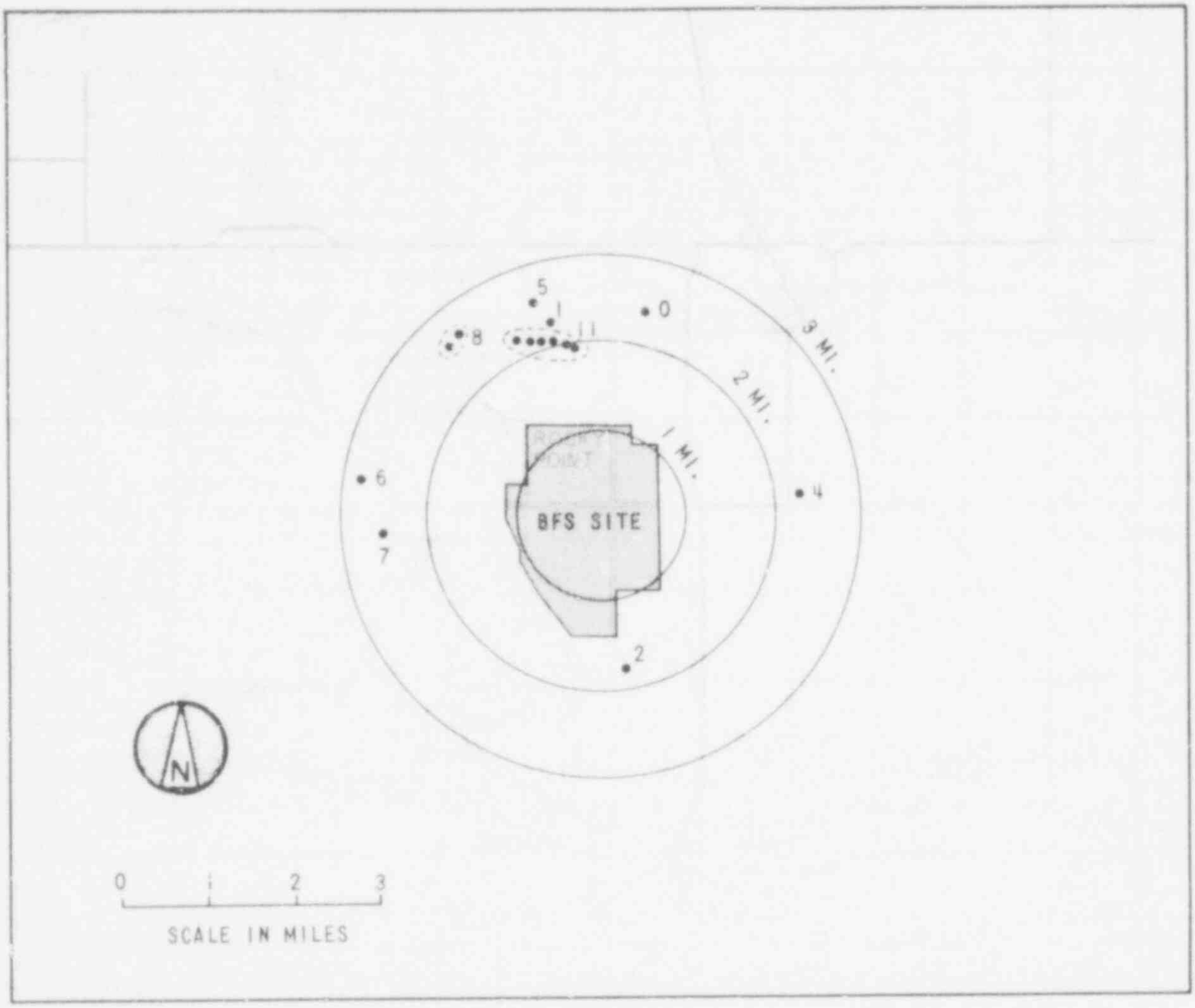


• WELL LOCATION (NUMBERS INDICATE POPULATION SERVED BY INDIVIDUAL WELLS OR BY GROUPS OF WELLS.)

Fig. 2.8. Domestic Wells and Population Served within Three Miles of BFS. From ER, Fig. 2.1-33.

POOR ORIGINAL

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POOR ORIGINAL

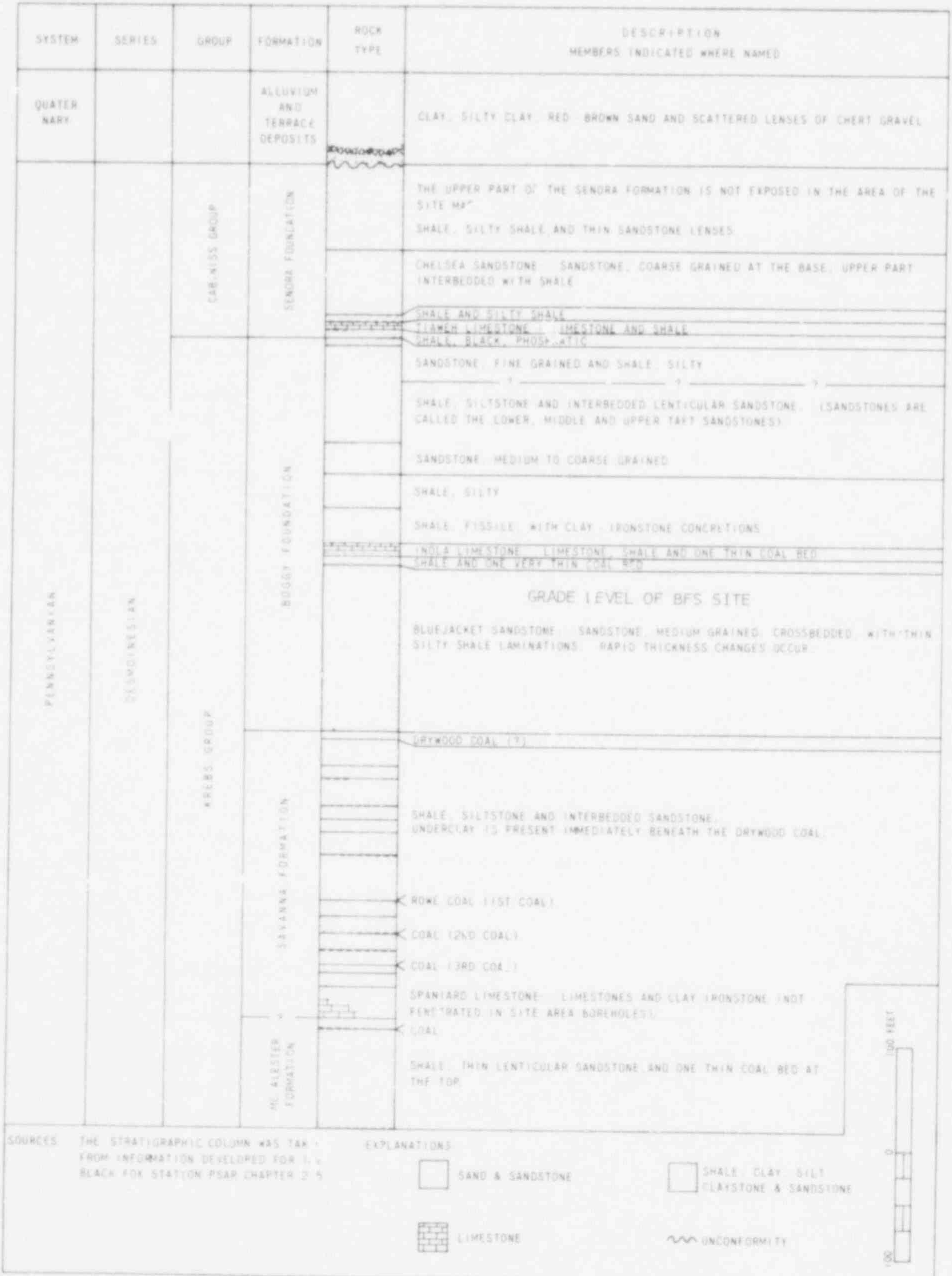



Fig. 2.9. Site Vicinity Stratigraphic Column. From ER, Fig. 2.5-4.

### 2.4.3 Soils

There are two soil associations at the site, the Dennis-Choteau and the Verdigris-Osage. The former occupies the nearly level to gently sloping valleys, but includes a few ridges where the soils are shallow to very shallow. The soils have developed on sandstone and shale. The major soil series in this association are nearly level to moderately sloping, and well drained or moderately well drained. Water erosion and maintenance of fertility are main problems in cultivating soils of this assocation. The Verdigris-Osage Association occurs along the Verdigris River and along Inola Creek. Nearly all the soils are on bottomlands and subject to occasional flooding. The Verdigris soils are deep, dark, loamy, and moderately well drained. The Osage soils are deep, dark clayey, and poorly drained. The problems associated with cultivation of soils of this association are due to relatively poor surface drainage and lack of soil structure maintenance.

### 2.4.4 Seismicity

The BFS site is in an area of relatively low seismicity, and there are no active faults or other geologic structures in the area that might localize seismic activity. The site is in a zone of minor expected damage from earthquakes.[4] Only 29 earthquakes with probable intensities of V or greater on the Modified Mercalli Scale have been recorded within 200 miles of the site, and only one has occurred within 50 miles. A more detailed account of the geology and seismicity of the region can be found in the ER, Section 2.5. Specific aspects of the site seismicity and engineering geology are discussed in Section 2.5 of the Preliminary Safety Analysis Report, and the staff's detailed analysis of these factors will be included in the Safety Evaluation Report.

## 2.5 HYDROLOGY

### 2.5.1 Surface Water

The Verdigris River Basin is one of the largest tributary basins of the Arkansas River drainage system in northeastern Oklahoma. Figure 2.10 shows the location and outline of the Verdigris Basin boundary and includes the larger tributaries, lakes, and reservoirs in the basin. Surface water features in the site vicinity include the Verdigris River, Inola, Pea, Commodore, and Bull Creeks, a small unnamed creek at the northern boundary of the site, and numerous small man-made ponds. Figure 2.11 shows the locations of the nearby watersheds relative to the site.

#### 2.5.1.1 Verdigris River

The Verdigris River originates in the southeastern corner of Chase County, Kansas, and flows generally south. It is joined by Willow Creek, Fall River, Elk River, Caney River, Bird Creek, and numerous other minor tributaries before its confluence with the Arkansas River near Muskogee, Oklahoma. The Verdigris is approximately 350 miles long and its basin drains 8300 square miles, 4290 of which are within Oklahoma. The drainage area of the river basin at the BFS site is estimated to be 7920 square miles. Water surface elevations vary from 1120 feet mean sea level (MSL) at the river's upper reaches to 500 feet MSL at its confluence with the Arkansas River. Near the site the surface elevation is relatively constant at about 532 feet MSL, as maintained by flow regulation at Newt Graham Lock and Dam (River Mile 35.5 and Channel Mile 26.5). The stream gradient from its headwaters to its mouth averages 1.8 feet per mile, but in the site vicinity the gradient is only 1.0 to 1.2 feet per mile.

The authorized project purposes for Oologah Reservoir are flood control, water supply and maintenance of navigation system pool levels. Hydroelectric power was also originally authorized for the project but has since been deleted as a project purpose. The dam is approximately 47 river miles upstream of the site. Flood control storage capacity is 965,000 acre-feet, including 15,600 acre-feet of sediment reserve. Conservation storage is 544,100 acre-feet including 33,500 acre-feet of sediment reserve. Allocations of conservation storage are 168,000 acre-feet for navigation storage and 342,600 acre-feet for water supply, of which 313,500 acre-feet is allocated to the City of Tulsa. Corps of Engineers' yield estimates for the conservation storage are based on the drought of record for the Verdigris River (July 1952 - May 1957), which has been estimated roughly to have about a 50-year return period. Based on these estimates, the City of Tulsa's share of the yield would be approximately 141 mgd. The applicant is currently working on an agreement with the City of Tulsa to purchase a portion of this estimated yield to provide cooling water makeup for the plant. Under this agreement, the Corps of Engineers would release water from the City of Tulsa's share to be picked up at the applicant's intake which will be located in the navigation pool formed by Newt Graham Lock and Dam. The applicant has

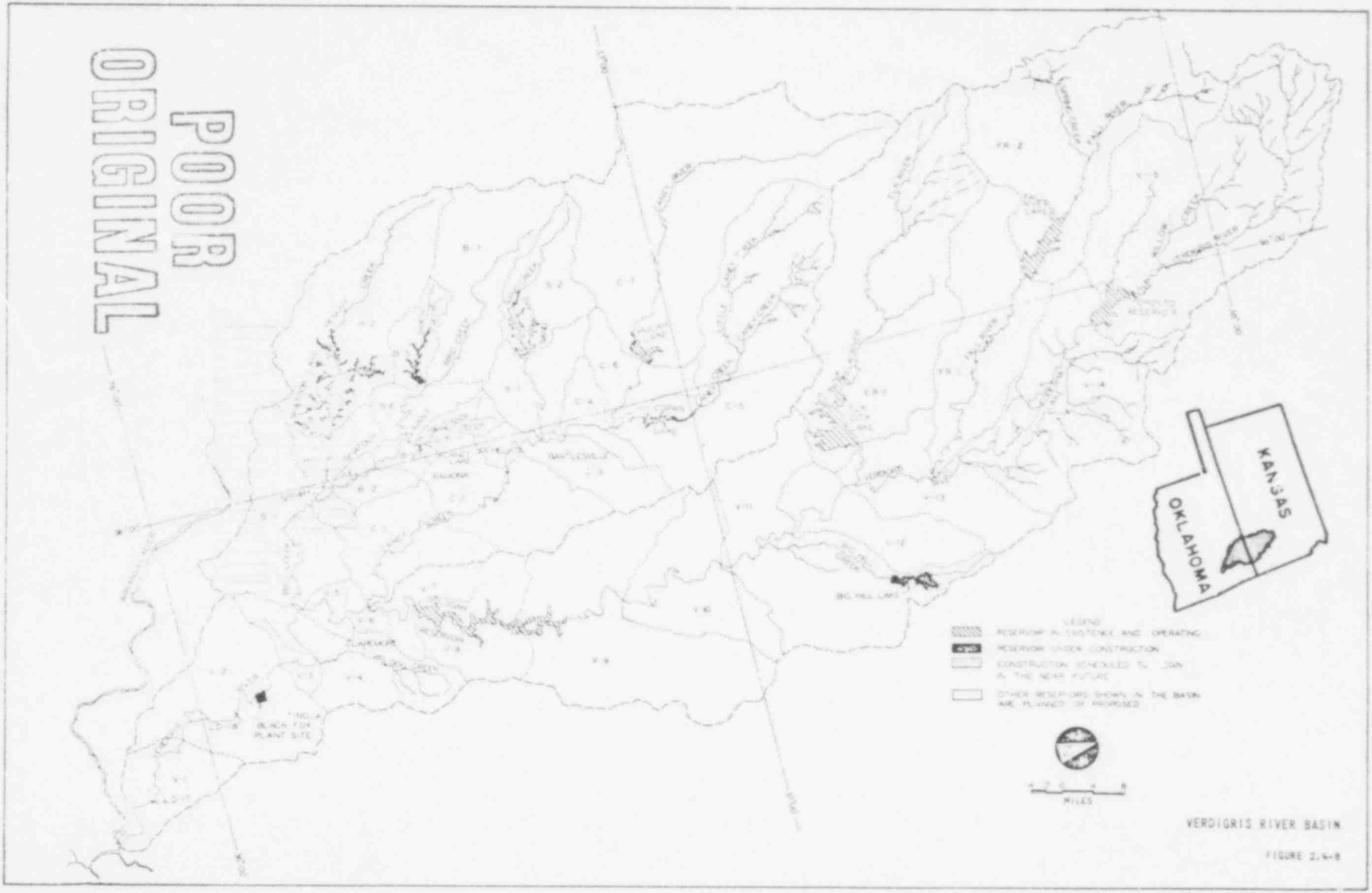
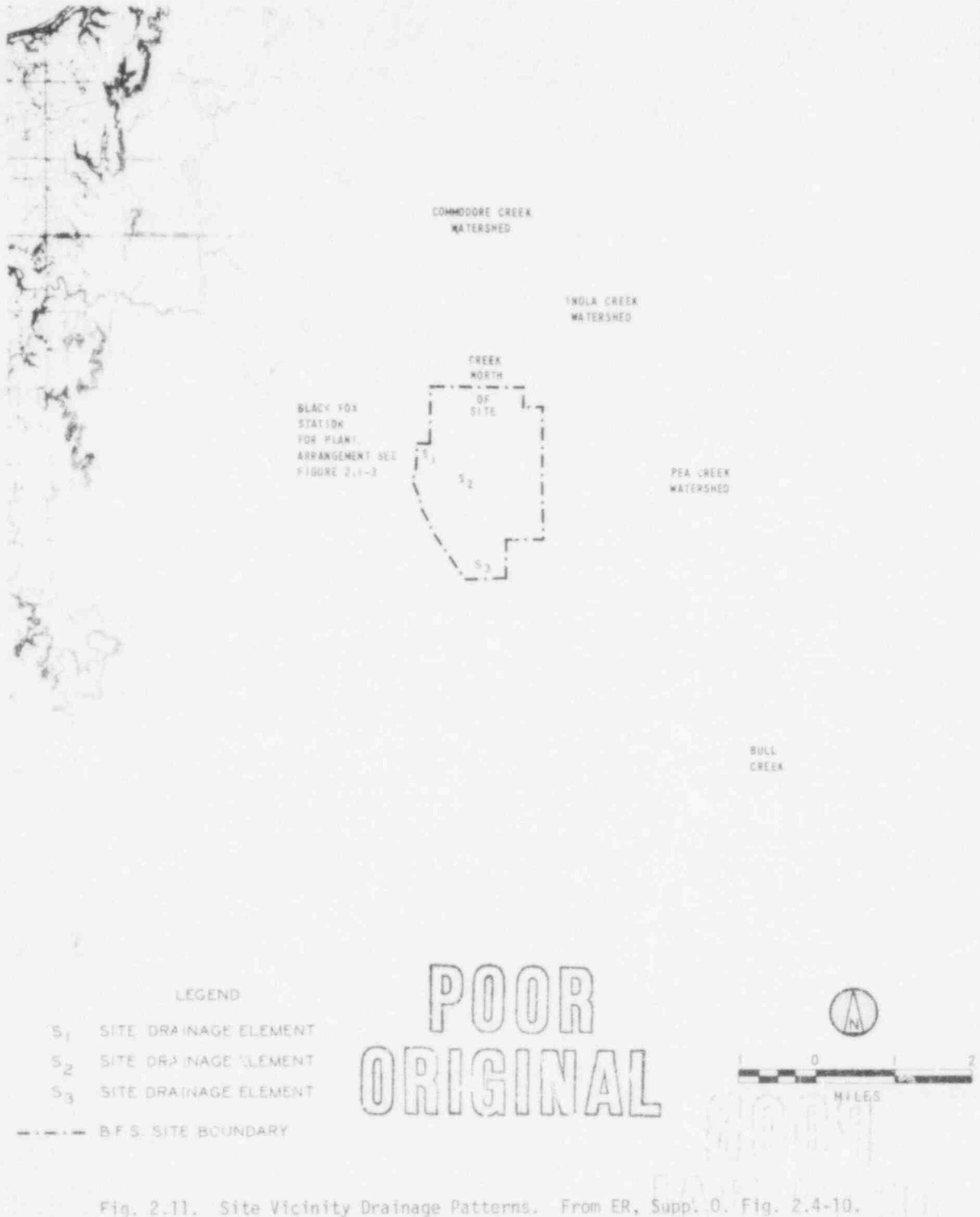



Fig. 2.10. Verdigris River Basin. From PSAR, Fig. 2.4-8.




POOR ORIGINAL

Fig. 2.11. Site Vicinity Drainage Patterns. From ER, Supp. 0. Fig. 2.4-10.

estimated that maximum makeup requirements at 100% load factor would be about 40 mgd. There will be minimal impact on navigation since no water released for navigational purposes will be used by the plant.

Historical flow data prior to channelization are of little use in post-channelization flow frequency estimates and are briefly discussed for the sake of maintaining perspective. The historical low flow occurred in January 1940, when the Claremore gage registered zero flow. The maximum flood of record, with an estimated peak discharge of 224,000 cfs, occurred at Inola on May 21, 1943. Since completion of the navigation system in 1970, the maximum recorded peak discharge at Newt Graham Lock and Dam was 63,000 cfs in November 1974, and the lowest recorded flow was 40 cfs on July 25, 1974. The probable maximum flood peak discharge in the site vicinity was estimated by the applicant to be about 555,200 cfs. Since the Corps of Engineers currently only releases from conservation storage in Oologah Reservoir for maintenance of the navigation system, it is possible under current procedure that no releases would be made for several days. However, the Corps of Engineers has estimated that the minimum flow into the lock and dam is probably about 40 cfs due to seepage from the reservoir and intervening area flow. In the future, it is anticipated that this minimum flow will probably be augmented as use of the navigation system increases (necessitating releases to maintain navigation pools) and due to releases to supply cooling water makeup to the plant.

According to a study by the applicant (ER, Supplement 6, December 3, 1976) and staff calculations, a recurrence of the 1953-1957 drought will not affect station operation due to availability of water. If the applicant obtains water rights on the Verdigris River from the City of Tulsa and no other supply or inflow supplements reservoir yield, the Black Fox Station and the Northeastern Stations will have sufficient water to operate for over two years.

There is potential for additional water available in the Verdigris basin. The City of Tulsa effluent discharges indirectly into the Verdigris. These discharges are supplemental to river flow and reservoir releases. This is possible because the present Tulsa water supply comes from outside the Oologah and Verdigris drainage basin. The volume of effluent discharges are expected to reach 36-38 MGD by 1983.[A] This volume alone is nearly enough to offset the station withdrawal of about 40 MGD.

Historical flow data prior to channelization are of little use in postchannelization flow frequency determinations and are briefly discussed here for the sake of maintaining perspective. The historical low flow occurred in January 1940, when the Claremore gage registered zero flow. The maximum flood of record, 224,000 cfs, occurred at Inola on May 21, 1943. Since completion of the navigation system in 1970, the maximum flow recorded at Newt Graham Lock and Dam was 63,000 cfs in November 1974. The lowest flow recorded at the lock and dam was 40 cfs on July 25, 1974. Median flow at Newt Graham Lock and Dam for the period September 1970 to October 1974 ranged from 500 cfs to 2000 cfs. The 30-day average extreme low flow past the site and Newt Graham Lock and Dam, as expected by the Corps of Engineers, when the navigation system is utilized to capacity, is 379 cfs. This estimate was based on water flow requirements and availability for maintaining the navigation system. Presently, the Probable Maximum Flood peak flow predicted in the site vicinity by the applicant (using Corps of Engineers' techniques) is 555,200 cfs (565.5 feet MSL).

### 2.5.1.2 Inola Creek

A section of Inola Creek runs along the eastern boundary of the site (Fig. 2.11). Inola Creek begins as an intermittent stream about four miles north of Inola, Oklahoma, and flows generally south and southwest about 17 miles to its confluence with Pea Creek. Below this confluence, Inola Creek flows southeast into an old channel of the Verdigris River that empties into the present channel about two miles downstream of Newt Graham Lock and Dam. The drainage area of the Inola Creek watershed is about 15.5 square miles. The shallow, slow-moving creek has an average depth of one foot or less, but has some pools three to four feet deep. Creek width varies from 5 to 30 feet, averaging approximately 9 feet. The average stream gradient is approximately 13 feet per mile. The creek has a narrow, V-shaped valley and drains an area of flat, undissected uplands.

The only known flow data for Inola Creek are measurements taken in the applicant's baseline studies during 1974. Measured flows ranged from 0 to 120 cfs. Creek elevation near the site during low flow was approximately 540 feet MSL. The estimated Probable Maximum Flood (PMF) peak stage for Inola Creek near its confluence with Pea Creek is 554.2 feet MSL (30,400 cfs).

2.5.1.3 Pea Creek

The Pea Creek watershed is adjacent to the eastern boundary of the Inola Creek watershed. Pea Creek, another intermittent stream, flows generally parallel to Inola Creek (Fig. 2.11). The creek is about 12 miles long and has a drainage area of about 14.5 square miles. Its elevation drops from 700 to 530 feet MSL and its average gradient is about 14 feet per mile.

2.5.1.4 Other Watersheds

Also near or within the site are the Commodore Creek watershed north of the site and a smaller, unnamed watershed that drains the northernmost section of the site (Fig. 2.11). The Commodore Creek watershed drains an area of approximately 6.4 square miles. Commodore Creek originates about four miles north of the site in Rogers County and flows generally south for approximately five miles to its confluence with the Verdigris River. Its elevation varies from 660 to 530 feet MSL, with an average gradient of approximately 26 feet per mile.

The unnamed watershed is partially located in the northern section of the plant site and has an area of 1.3 square miles. It is drained by a small intermittent stream that discharges directly into the Verdigris River. The stream originates about a half mile north of the site in Rogers County and flows south for 2.2 miles. Elevations vary from 620 to 520 feet MSL, and the average gradient is approximately 45 feet per mile.

No gaging stations are known to be located within either of these watersheds.

Runoff from the 3.5 square miles of site drainage is discharged by natural watercourses to the small creek to the north, Inola Creek to the east, and the Verdigris River to the west.

The central site drainage area is divided into three subareas (Fig. 2.11) draining generally from north to south and discharging directly into the Verdigris River. The western subarea ($S_1$) covers about 0.19 square mile, with an average drainageway gradient of 139 feet per mile. The central subarea ($S_2$) encompasses 1.1 square miles, with an average stream gradient of 56 feet per mile. The eastern subarea ($S_3$) includes 0.75 square mile and has an average gradient of 41 feet per mile.

2.5.1.5 Small Onsite Ponds

There are about 30 small man-made ponds on the site and several dozen in the vicinity. The ponds are generally used for watering stock and vary in area from about one acre to about ten acres. Diem's Pond, just west of the proposed station complex, is the largest (10 acres). Some of the ponds will be eliminated during construction and others will be increased to provide a settling pond and holding pond for station use (Fig. 2.12).

2.5.2 <u>Groundwater</u>

There are two major types of groundwater systems in the area within 50 miles of the site--shallow and deep aquifers. Shallow aquifers are those exposed at the surface; the deep aquifers are not exposed within 50 miles of the site.

Deep aquifers exist in northeastern Oklahoma in the area east of the Neosho River. These aquifers are at depths generally from 500 to 1500 feet[1] and are separated from surface recharge by relatively impermeable rocks. The deep aquifers are recharged by precipitation in their outcrop area in western Missouri. The deep aquifers consist generally of sandy and cherty dolomite. Wells in these aquifers are known to yield 200 to 1000 gpm.[1] West of the Neosho River the aquifers trend increasingly deeper and are impractical for use as water supplies.

Shallow aquifers in the area within 50 miles of the site consist of consolidated rock exposed or at shallow depths, alluvium, and terrace deposits. Recharge to these aquifers is from precipitation in the immediate vicinity of the area and surface water seepage from streams or lakes.

Alluvial deposits along the Arkansas River and portions of the Verdigris River provide the most favorable source of groundwater in the area within 50 miles of the site. The alluvium thickness along the Arkansas varies from about 33 feet at Tulsa to about 55 feet at Webbers Falls. Yields


Fig. 2.12. Site Drainage System. From PSAR, Fig. 2.4-14.

to wells in the alluvium range from 20 to 400 gpm.[1] Terrace deposits along the Arkansas River range in thickness from about 70 to 90 feet and yield from 20 to 125 gpm. Alluvium along the Verdigris River consists of clay and silt grading downward into several feet of fine to coarse sand and gravel. Wells tapping the thicker, coarser sands may yield up to 75 gpm.[1] The terrace deposits along the Verdigris are generally too fine-grained to yield significant amounts of water.[1]

Groundwater in the site area is primarily used for domestic and stock-watering purposes, with only one recorded permit for use in irrigation (ER, Sec. 2.4.2.2, Supp. 0). Future use is expected to be limited due to the low availability of groundwater. Locations of water wells on and near the site are shown in Figures 2.8 and 2.13.

The average water table elevation in the site vicinity varies from 540 feet MSL in the Verdigris River floodplain adjacent to the site through 555 feet MSL in the terrace deposits in the southern portion of the site to about 560 and 575 feet MSL in bedrock beneath the site central complex area (PSAR, App. 2B). From the site central complex area the water table slopes generally to the south, while eastward from the site it slopes slightly toward Inola Creek. The average gradient is about 80 feet per mile in the bedrock, 15 feet per mile in the terrace deposits, and 10 feet per mile in the floodplain alluvium.

Groundwater-level fluctuation in the floodplain alluvium is from one to five feet with river-level changes (ER, Supp. 0, Sec. 2.4.2.4). Groundwater-level fluctuations in the terrace deposits occur annually with rainfall and evaporation cycles. The highest groundwater levels usually occur from February to April and the lowest in the fall and early winter.

### 2.5.3 Water Quality

#### 2.5.3.1 Surface Water

Since the station will use the Verdigris River as its source of water supply and as the receiving body for its liquid discharges, discussion of its water quality is important. Because of the presence of excessive amounts of oil brine and soluble material from upstream rock formations, water from the Verdigris and its tributaries generally has not met accepted water quality standards. However, where impoundments hold surface waters for settling and mixing, water is of adequate quality for most uses. This upgrading of water quality has been observed for the Verdigris through comparisons of water quality data collected before and after channel modifications and flow regulation. A statistical comparison of relevant parameters versus flow prior to and after flow regulation (ER, App. 2C) indicated that quality differences are distinct between the two periods.

The available water quality data on the Verdigris River come from two sources: USGS Water Quality Records and the applicant's baseline data collected during 1974. The water quality of the Verdigris River from Oologah Reservoir to the Arkansas River is rated by the Oklahoma Water Resources Board as "fair" for municipal water supplies and irrigation. Water analyses by the USGS for water year October 1973 to September 1974 for the Verdigris River at Newt Graham Lock and Dam are presented in Tables 2.4 and 2.5. The applicant's preoperational baseline water quality data are summarized in Tables 2.6 and 2.7, which are for two sampling stations on the Verdigris River adjacent to the site (see Fig. 2.15 below).

#### 2.5.3.2 Groundwater

The groundwater within about 100 feet of the surface has a relatively low concentration of dissolved solids and is generally usable for domestic supplies. At greater depth, much of it is too mineralized for good domestic or stock water. The uppermost levels of groundwater are moderately hard to very hard and commonly have a sulfurous odor.

A more detailed account of the hydrology and water quality of the site and region can be found in the ER, Section 2.4 and Appendices 2B and 2C, and in the PSAR, Section 2.4. The detailed discussion of the hydrologic aspects of plant safety review will be covered in the staff's Safety Evaluation Report.

## 2.6. METEOROLOGY

### 2.6.1 Regional Climatology

Northeast Oklahoma, where the Black Fox site is located, can be described as having a continental-type climate that is modified by the influence of the Gulf of Mexico. Temperatures in the region can range from below zero to over 100°F during the course of a year, although normal daily maximums range from the mid-40s in winter to the low 90s in mid-summer. Normal daily minimums vary from the mid-20s in the winters to the low 70s during the summers.[5]

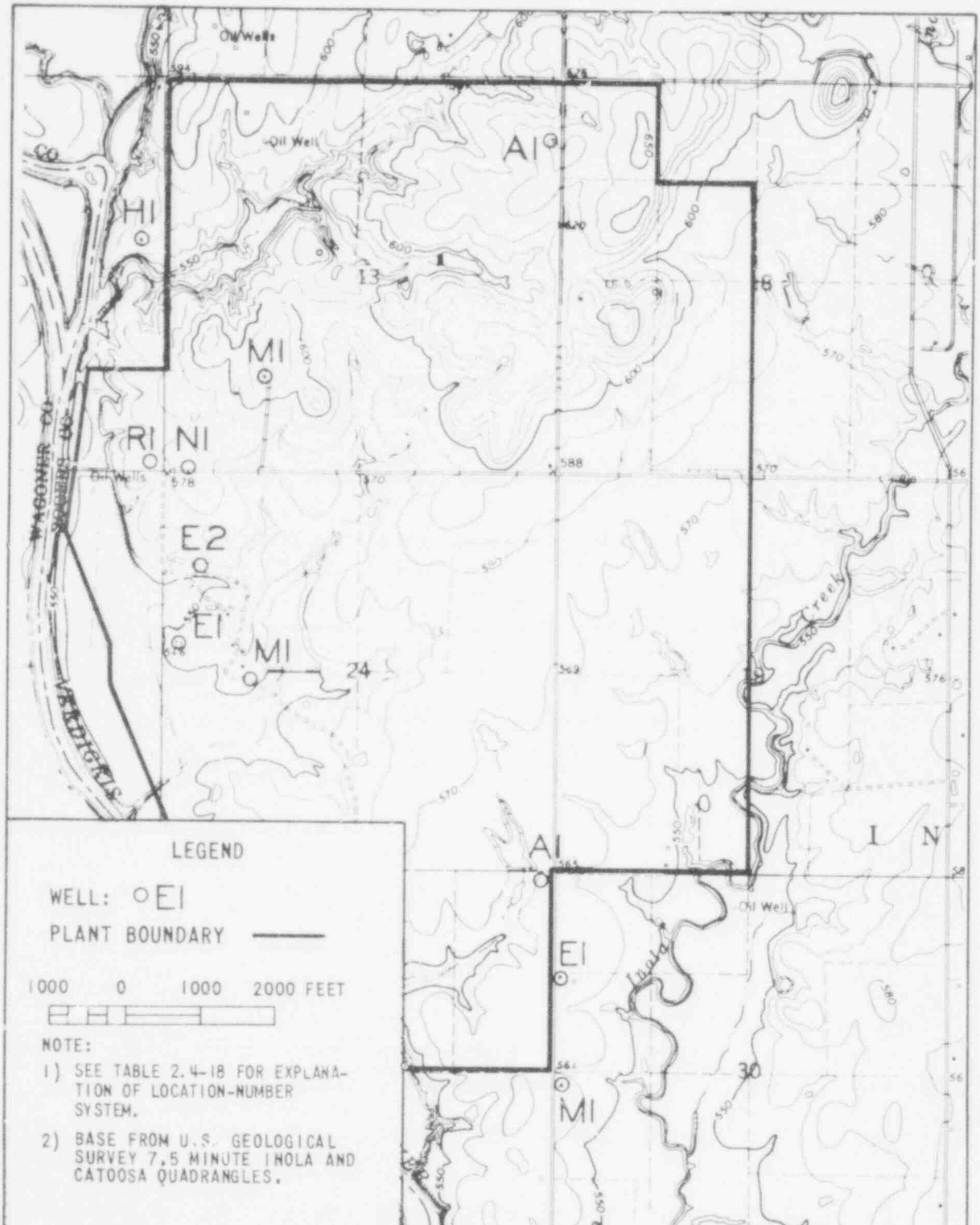



Fig. 2.13. Representative Water Wells in the Site Area. From ER, Fig. 2.4-15.

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Table 2.4. Water Quality Analyses of Verdigris River at Newt Graham Lock and Dam[a,b]

| Date[c] | Dissolved Calcium | Dissolved Magnesium | Dissolved Sodium | Bicarbonate | Carbonate | Alkalinity as $CaCO_3$ | Dissolved Sulfate | Dissolved Chloride | Dissolved Nitrate | Total Phosphorus | Dissolved Solids (residue at 180 C) | Hardness (Ca, Mg) | Noncarbonate Hardness | Specific Conductance (micromhos) | pH (units) | Carbon Dioxide |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Oct | | | | | | | | | | | | | | | | |
| 05 | -- | 4.9 | 18 | 69 | 0 | 57 | 21 | 31 | 2.9 | 0.11 | 159 | -- | -- | 261 | 7.9 | 1.4 |
| 15 | 26 | 4.7 | 14 | 80 | 0 | 66 | 20 | 22 | 1.5 | 1.1 | 156 | 84 | 19 | 244 | 7.5 | 4.0 |
| 25 | 47 | 8.5 | 20 | 150 | 0 | 123 | 36 | 29 | 2.4 | 0.92 | 232 | 150 | 29 | 403 | 8.1 | 1.9 |
| Nov | | | | | | | | | | | | | | | | |
| 05 | 41 | 7.0 | 16 | 132 | 1 | 110 | 26 | 23 | 2.9 | 0.24 | 203 | 130 | 21 | 316 | 8.5 | 0.7 |
| 15 | -- | 6.7 | 15 | 127 | 0 | 104 | 24 | 24 | 2.6 | 0.27 | 193 | -- | -- | 332 | 8.2 | 1.3 |
| 25 | 33 | 5.2 | 13 | -- | 0 | -- | 21 | 19 | 2.5 | 0.49 | 165 | 100 | -- | 278 | 7.7 | -- |
| Dec | | | | | | | | | | | | | | | | |
| 05 | -- | 6.2 | 18 | 104 | 0 | 85 | 26 | 31 | 2.1 | 0.25 | 200 | -- | -- | 325 | 8.1 | 1.3 |
| 15 | 39 | 6.1 | 15 | 124 | 0 | 102 | 23 | 23 | 2.2 | 0.30 | 202 | 120 | 21 | 328 | 8.2 | 1.3 |
| 25 | -- | 5.6 | 17 | 89 | 0 | 73 | 24 | 28 | 1.9 | 0.27 | 183 | -- | -- | 295 | 7.5 | 4.5 |
| Jan | | | | | | | | | | | | | | | | |
| 05 | 37 | 6.3 | 15 | 116 | 0 | 95 | 24 | 24 | 3.1 | 0.09 | 182 | 120 | 23 | 309 | 8.2 | 1.2 |
| 15 | 39 | 6.3 | 15 | 119 | 0 | 98 | 25 | 24 | 2.8 | 0.11 | 186 | 120 | 26 | 318 | 7.8 | 3.0 |
| 25 | 41 | 6.8 | 17 | 122 | 0 | 100 | 28 | 29 | 2.5 | 0.10 | 197 | 130 | 30 | 350 | 7.7 | 3.9 |
| Feb | | | | | | | | | | | | | | | | |
| 05 | 44 | 7.6 | -- | 138 | 0 | 113 | 33 | 29 | 2.5 | 0.14 | 221 | 140 | 28 | 382 | 8.0 | 2.2 |
| 15 | 51 | 10 | -- | 151 | 0 | 124 | 47 | 42 | 3.4 | 0.16 | 276 | 170 | 45 | 479 | 7.8 | 3.8 |
| 25 | 38 | 7.7 | 26 | 112 | 0 | 92 | 33 | 42 | 2.9 | 0.15 | -- | 130 | 35 | 398 | 7.4 | 7.1 |
| Mar | | | | | | | | | | | | | | | | |
| 05 | 49 | 8.1 | 21 | 145 | 0 | 119 | 37 | 32 | 1.9 | 0.10 | 235 | 160 | 37 | 422 | 7.8 | 3.7 |
| 12 | 17 | 3.6 | 16 | 48 | 0 | 39 | -- | 21 | 4.7 | 0.22 | -- | 57 | 18 | 160 | 7.1 | 6.1 |
| 25 | 36 | 7.7 | -- | 115 | 0 | 94 | -- | -- | -- | 0.06 | 238 | 120 | 27 | 343 | 7.8 | 2.9 |
| Apr | | | | | | | | | | | | | | | | |
| 05 | 35 | 5.4 | 12 | -- | 0 | -- | 23 | 18 | -- | -- | 171 | 110 | -- | 284 | 7.9 | -- |
| 15 | 36 | 6.2 | 16 | 109 | 0 | 89 | 30 | 23 | -- | -- | 188 | 120 | 26 | 316 | 7.8 | 2.8 |
| 25 | 49 | 8.6 | 27 | 137 | 0 | 112 | 40 | 47 | -- | 0.16 | 257 | 160 | 45 | 445 | 7.9 | 2.8 |
| May | | | | | | | | | | | | | | | | |
| 05 | 29 | 5.8 | 19 | 89 | 0 | 73 | 25 | -- | -- | 0.23 | 182 | 96 | 23 | 293 | 7.9 | 1.8 |
| 15 | 37 | 7.2 | 15 | 110 | 0 | 90 | -- | 23 | -- | 0.19 | 192 | 120 | 32 | 311 | 7.6 | 4.4 |
| 25 | 44 | 8.3 | 17 | -- | 0 | -- | 37 | 27 | -- | 0.14 | 222 | 140 | -- | 363 | 7.9 | -- |

Table 2.8. Continued

| Date[c] | Dissolved Calcium | Dissolved Magnesium | Dissolved Sodium | Bicarbonate | Carbonate | Alkalinity as $CaCO_3$ | Dissolved Sulfate | Dissolved Chloride | Dissolved Nitrate | Total Phosphorus | Dissolved Solids (residue at 180 C) | Hardness (Ca, Mg) | Noncarbonate Hardness | Specific Conductance (Micromhos) | pH (units) | Carbon Dioxide |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Jun | | | | | | | | | | | | | | | | |
| 05 | 46 | 8.7 | 17 | -- | 0 | -- | 34 | 26 | -- | -- | 223 | 150 | -- | 374 | 8.0 | -- |
| 15 | 42 | 7.7 | 16 | 133 | 0 | 109 | -- | 23 | -- | 0.11 | 211 | 140 | 28 | 344 | 8.1 | 1.7 |
| 25 | 46 | 7.1 | 16 | 139 | 0 | 114 | 30 | 23 | -- | 0.23 | 201 | 140 | 26 | 350 | 8.0 | 2.2 |
| Jul | | | | | | | | | | | | | | | | |
| 04 | 42 | 7.4 | 15 | 132 | 0 | 108 | -- | 22 | -- | 0.04 | 199 | 140 | 27 | 331 | 7.9 | 2.7 |
| 15 | 40 | 6.5 | 13 | 125 | 0 | 103 | -- | 20 | -- | 0.00 | 192 | 130 | 24 | 311 | 8.0 | 2.0 |
| 25 | 41 | 7.1 | 15 | 127 | 0 | 104 | 30 | 18 | -- | 0.09 | 185 | 130 | 26 | 319 | 8.3 | 1.0 |
| Aug | | | | | | | | | | | | | | | | |
| 05 | 39 | 8.1 | 14 | 131 | 0 | 107 | -- | 17 | -- | 0.08 | 207 | 130 | 23 | 328 | 8.0 | 2.1 |
| 15 | 26 | 6.1 | 16 | 80 | 0 | 66 | 20 | 28 | -- | 0.28 | 156 | 90 | 24 | 263 | 7.6 | 3.2 |
| 25 | 39 | 8.6 | 31 | 109 | 0 | 89 | 24 | 56 | -- | 0.38 | 244 | 130 | 41 | 412 | 8.0 | 1.7 |
| Sep | | | | | | | | | | | | | | | | |
| 04 | 18 | 2.2 | -- | 51 | 0 | 42 | 13 | 23 | -- | 0.18 | 125 | 54 | 12 | 189 | 7.2 | 5.1 |
| 15 | 42 | 5.2 | -- | 132 | 0 | 108 | 27 | 19 | -- | 0.14 | 194 | 130 | 22 | 325 | 7.8 | 3.3 |
| 25 | 28 | 5.7 | 14 | -- | 0 | -- | 23 | 21 | -- | 0.16 | 156 | 93 | -- | 257 | 8.2 | -- |

[a]Location--Lat. 36°03'24" N, Long. 95°32'06" W, in NW 1/4 NE 1/4 sec 7, T.18 N., R. 17 E., Wagoner County at lock wall at dam, 6.8 mi (10.9 km) southwest of Inola, and at 25.7 navigation channel miles (41.4 km).

[b]Units are milligrams per liter (mg/ℓ) unless otherwise stated.

[c]Water quality data, water year October 1973 to September 1974.

From "Water Resources Data for Oklahoma," Part II: Water Quality Records, USGS, 1974.

Table 2.5. Trace Element Analyses for Verdigris River at Newt Graham Lock and Dam, 1974

| Parameter[a] | Date | | |
|---|---|---|---|
| | May 29 | June 25 | Sep 25 |
| Instantaneous discharge, cfs | 18,000 | 10,600 | 7,000 |
| Total iron | 5,600 | 2,300 | 1,800 |
| Dissolved iron | 130 | 30 | 260 |
| Total manganese | 200 | 100 | 40 |
| Suspended manganese | 200 | 80 | 30 |
| Dissolved manganese | 0 | 20 | 10 |
| Total organic carbon, mg/ℓ | 7.7 | -- | -- |
| Total arsenic | 3 | 3 | 2 |
| Suspended arsenic | 3 | 1 | 0 |
| Dissolved arsenic | 0 | 2 | 2 |
| Total cadmium | <10 | <10 | <10 |
| Suspended cadmium | <9 | <9 | <9 |
| Dissolved cadmium | 0 | 1 | 1 |
| Total chromium | 10 | 0 | 0 |
| Suspended chromium | 10 | 0 | 0 |
| Dissolved chromium | 0 | 0 | 0 |
| Total cobalt | <50 | <50 | <50 |
| Suspended cobalt | <49 | <50 | <49 |
| Dissolved cobalt | 1 | 0 | 1 |
| Total copper | 50 | <10 | <10 |
| Suspended copper | 38 | <6 | <7 |
| Dissolved copper | 12 | 4 | 3 |
| Total lead | <100 | <100 | <100 |
| Suspended lead | <97 | <96 | <95 |
| Dissolved lead | 3 | 4 | 5 |
| Total mercury | 0.0 | 0.1 | -- |
| Suspended mercury | 0.0 | 0.1 | -- |
| Dissolved mercury | 0.0 | 0.0 | 0.0 |
| Total selenium | 1 | 0 | 0 |
| Suspended selenium | 1 | 0 | 0 |
| Dissolved selenium | 0 | 1 | 0 |
| Total zinc | 90 | 30 | 40 |
| Suspended zinc | 50 | 30 | 40 |
| Dissolved zinc | 40 | 0 | 0 |

[a]All units in micrograms per liter (μg/ℓ) unless otherwise noted.

From "Water Resources Data for Oklahoma," Part II: Water Quality Records, USGS, 1974.

Table 2.6. Summary of Water Quality Parameters Measured at Aquatic Station 1 (Verdigris River), August through December 1974

| Parameters[a] | Number of Field Samples[b] | Minimum | Maximum | Mean |
|---|---|---|---|---|
| Temperature (°C) | 4 | 6.2 | 27.4 | 18.3 |
| Dissolved oxygen (mg/l) | 4 | 5.4 | 13.1 | 9.3 |
| Oxygen saturation (%) | 4 | 68 | 124 | 95 |
| pH | 4 | 6.9 | 7.5 | 7.3 |
| Alkalinity, total (mg/l-$CaCO_3$) | 4 | 43 | 114 | 92 |
| Turbidity (Jackson Turbidity Units) | 4 | 20 | 480 | 240 |
| Suspended solids, total (mg/l) | 4 | 14 | 307 | 83 |
| Dissolved solids, total (mg/l) | 4 | 133 | 209 | 186 |
| Specific conductance (μmhos/cm) | 4 | 205 | 350 | 307 |
| Calcium (mg/l) | 4 | 17 | 52 | 37 |
| Magnesium (mg/l) | 4 | 3.7 | 7.7 | 6.0 |
| Potassium (mg/l) | 4 | 2.9 | 3.5 | 3.3 |
| Sodium (mg/l) | 4 | 13 | 22 | 16 |
| Chloride (mg/l) | 4 | 20 | 31 | 25 |
| Sulfate (mg/l) | 4 | 12 | 31 | 24 |
| Fluoride (mg/l) | 4 | 0.15 | 0.24 | 0.19 |
| Ammonia (mg/l-N) | 4 | 0.10 | 0.79 | 0.30 |
| Nitrite (mg/l-N) | 4 | 0.005 | 0.01 | 0.002 |
| Nitrate (mg/l-N) | 4 | 0.07 | 0.63 | 0.24 |
| Organic nitrogen, total (mg/l-N) | 4 | 0.53 | 1.3 | 0.76 |
| Orthophosphate (mg/l-P) | 4 | 0.11 | 0.22 | 0.16 |
| Phosphorus, total soluble (mg/l-P) | 4 | 0.04 | 0.20 | 0.13 |
| Phosphorus, total (mg/l-P) | 4 | 0.17 | 0.22 | 0.18 |
| Silica, soluble (mg/l-$SiO_2$) | 4 | 3.0 | 7.2 | 5.6 |
| Biochemical oxygen demand, 5-day (mg/l) | 4 | 1.0 | 3.0 | 2.1 |
| Chemical oxygen demand (mg/l) | 4 | 9.7 | 29.6 | 16.1 |
| Organic carbon (mg/l) | 3 | 8.6 | 15 | 10.7 |
| Bacteria, total coliform (organisms/100 ml) | 4 | 1400 | 8500 | 3825 |
| Bacteria, fecal coliform (organisms/100 ml) | 4 | 34 | 407 | 215 |
| Bacteria, fecal streptococci (organisms/100 ml) | 4 | 10 | 1400 | 470 |

[a]Values of temperature, dissolved oxygen, oxygen saturation, and pH are from surface measurements. All other parameter values were determined from a sample made by compositing water subsamples collected at one-meter depth intervals between the river surface and bottom.

[b]Sampling dates were August 13, September 17, October 8, and December 10, 1974, when Verdigris River flows were 2000, 5000, 2000, and 11,000 cfs, respectively.

From ER, Table 2.4-2.

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Table 2.7. Summary of Water Quality Parameters Measured at Aquatic Station 2 (Verdigris River), February through December 1974

| Parameters[a] | Number of Field Samples[b] | Minimum | Maximum | Mean |
|---|---|---|---|---|
| Temperature (°C) | 11 | 6.2 | 28.8 | 17.9 |
| Dissolved oxygen (mg/l) | 11 | 5.4 | 13.2 | 9.2 |
| Oxygen saturation (%) | 11 | 65 | 125 | 94 |
| pH | 11 | 6.5 | 7.9 | 7.3 |
| Alkalinity, total (mg/l-$CaCO_3$) | 11 | 44 | 155 | 109 |
| Turbidity (Jackson Turbidity Units) | 11 | 22 | 510 | 132 |
| Suspended solids, total (mg/l) | 11 | 20 | 304 | 95 |
| Dissolved solids, total (mg/l) | 11 | 128 | 293 | 217 |
| Specific conductance (μmhos/cm) | 11 | 230 | 500 | 356 |
| Calcium (mg/l) | 11 | 18 | 59 | 40 |
| Magnesium (mg/l) | 11 | 3.7 | 9.8 | 7.1 |
| Potassium (mg/l) | 11 | 2.4 | 3.4 | 3.0 |
| Sodium (mg/l) | 11 | 11 | 34 | 19 |
| Chloride (mg/l) | 11 | 2.7 | 62 | 28 |
| Sulfate (mg/l) | 11 | 10 | 47 | 33 |
| Fluoride (mg/l) | 11 | 0.14 | 0.30 | 0.19 |
| Ammonia (mg/l-N) | 10 | <0.01 | 0.68 | 0.23 |
| Nitrite (mg/l-N) | 11 | <0.005 | 0.04 | 0.009 |
| Nitrate (mg/l-N) | 11 | 0.11 | 0.32 | 0.15 |
| Organic nitrogen, total (mg/l-N) | 11 | 0.04 | 2.0 | 0.70 |
| Orthophosphate (mg/l-P) | 11 | 0.01 | 0.24 | 0.11 |
| Phosphorus, total soluble (mg/l-P) | 11 | 0.03 | 0.22 | 0.11 |
| Phosphorus, total (mg/l-P) | 11 | 0.05 | 0.24 | 0.14 |
| Silica, soluble (mg/l-$SiO_2$) | 11 | 3.6 | 7.8 | 5.6 |
| Biochemical oxygen demand, 5-day (mg/l) | 11 | <1.0 | 3.0 | 1.6 |
| Chemical oxygen demand (mg/l) | 11 | 10.5 | 30.0 | 15.7 |
| Organic carbon, total (mg/l) | 6 | 0.5 | 11.4 | 6.0 |
| Bacteria, total coliform (organisms/100 ml) | 11 | 320 | 6900 | 3090 |
| Bacteria, fecal coliform (organisms/100 ml) | 11 | 6 | 2300 | 570 |
| Bacteria, fecal streptococci (organisms/100 ml) | 11 | 30 | 2200 | 710 |

[a]Values of temperature, dissolved oxygen, oxygen saturation, and pH are from surface measurements. All other parameter values were determined from a sample made by compositing water subsamples collected at one meter depth intervals between the river surface and bottom.

[b]Sampling dates were February 13, March 20, April 10, April 30, May 19, June 18, July 16, August 13, September 17, October 8, and December 10, 1974, when Verdigris River flows were 2000; 28,000; 10,000; 3000; 8000; 17,000; 7000; 2000; 5000; 2000; and 11,000 cfs, respectively.

From ER, Table 2.4-3.

Precipitation is generally spread throughout the year, with the annual average totaling about 40 inches; slight peaks in the monthly totals occur during spring and early summer. These peaks are due to the occurrence of thunderstorms that are usually localized phenomena. Winter snowfall on the average amounts to less than four inches, although a total of nearly 12 inches in one month was observed at Tulsa in 1968, which is the maximum since 1931 when observations began at the airport.[5]

### 2.6.2 Local Meteorology

Meteorological observations, since 1931, from the National Weather Service office at the Tulsa airport provide the foundation for describing the local meteorological conditions that are applicable to the site. In addition, cooperative weather observations of temperature and precipitation have been made at surrounding locations[6] since before 1951.

In November 1973, meteorological measurements were begun at the Black Fox site. Temperatures measured at the 33-foot level ranged from a high of 104°F to a low of 7°F during the period December 1973 - November 1974, and the average monthly maximum temperature was 68°F and the minimum 49°F. Precipitation measured onsite totaled 43 inches during this period (ER, Appendix 2A), with maximum monthly totals observed during May and June and again in September. Prevailing winds onsite are from the south, as are those observed at Tulsa, with a lower frequency of winds from the north. Visibility restrictions due to fog as measured onsite occurred 212 hours during the year for visibility less than one mile, compared to 518 hours during the year at Tulsa with visibility less than half a mile.

### 2.6.3 Severe Weather

The predominant severe weather phenomena affecting the site area are tornadoes and thunderstorms. The safety aspects of these phenomena will be discussed in detail in the Safety Evaluation Report. Strong winds are observed, usually associated with thunderstorms and frontal passages. Hurricanes that affect the Gulf Coast generally are not expected to produce significant impact at the site due to the nearly 800 km distance of the plant site to the coast. Hail is observed frequently, usually coinciding with severe thunderstorms, while ice storms are observed on an average of about five days a year. Area snowfall is, as a rule, light, with the greatest 24-hour amount observed at Tulsa being less than 12 inches through 1973.

## 2.7 ECOLOGY

### 2.7.1 Terrestrial

The BFS site is in the Cherokee Prairie biotic district (ER, Sec. 2.2.2.2). To the east is the Ozark biotic district, and to the west is the Osage Savanna biotic district. Staff observations during a site visit indicated an ecotonal (transitional) character for the entire region. On a transect from Siloam Springs, Arkansas, to Tulsa, Oklahoma (helicopter overflight at 500 to 1200 feet above ground) and from Tulsa to near Stroud, Oklahoma (along Turner Turnpike, Interstate Highway 44), the vegetation is a mosaic of communities. From Siloam Springs to the Verdigris River, the frequency of Ozark forest stands decreases, and these stands are increasingly confined to sheltered sites. The frequency of Osage Savanna stands gradually decreases eastward along the entire transect, and these stands are increasingly confined to exposed sites. Cherokee Prairie stands become less frequent in either direction from the Grand (Neosho) River, and are typically found on relatively level sites throughout. Because of this complexity, the staff has done multivariate (ordinational*) analyses of the applicant's baseline vegetational data; these analyses are discussed in Section 5.6.1.2.

#### 2.7.1.1 Vegetation

The applicant recognized 11 vegetational mapping units (approximately equivalent to biotic associations) at the BFS site, and sampled the six major associations. The sampling regime is described in Section 6. Figure 2.14 shows the distribution of these vegetational mapping units on the BFS site and the locations of the sample plots. The staff believes that a twelfth vegetational mapping unit should be added (see Sec. 5.6.1.2).

- Mesic Upland Woods--This association (post oak-black hickory, see Appendix G) is represented on the BFS site by a single stand in a sheltered ravine. The staff believes the implicit age distribution (distribution of size classes, Table 2.8) to represent a reasonably well-developed

*Multivariate (ordinational) analyses are techniques by which sampling data are arranged in a logical order, so that the biological structure of various communities can be compared.

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Fig. 2.14. Vegetative Cover Map and Land Use Map of BFS Site, 1974. From ER, Fig. 2.2-3.

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Table 2.8. BFS Site Vegetation

| Parameter | Plot[a] A | B | D | E | F | H |
|---|---|---|---|---|---|---|
| Acreage[b] | 100 | 220 | 219 | 486 | 495 | 495 |
| Tree density[c] | 155 | 290 | - | - | - | - |
| Sapling density[c] | 1069 | 852 | - | - | - | - |
| Seedling density[c] | 650 | 975 | - | - | - | - |
| Ground flora biomass[d] | | | | | | |
| May | 136 | n/s[e] | 376 | 308 | 248 | n/s |
| July | 147 | 184 | 529 | 574 | 254 | n/s |
| August | 125 | 121 | n/s | 572 | 201 | 479 |

[a]Key to plots:
A. Xeric upland woods
B. Mesic upland woods
D. Prairie hay
E. Lowland unimproved pasture
F. Upland pasture
H. Lowland improved pasture

[b]Total acreage on BFS site covered by the association.

[c]Individuals per acre.

[d]Grams per square meter.

[e]"n/s" = not sampled.

forest, but notes that the shift in dominance of saplings (to winged elm-black hickory, see Appendix G) implies a successional forest. The applicant reported grazing in this stand. This is borne out by the seedling densities, which appear low compared with the saplings; however, the ground flora biomass (Table 2.8) does not suggest a strong grazing disturbance.

• Xeric Upland Woods--There is a single stand of this association (post oak-blackjack oak, see Appendix G) on the BFS site. The low density of trees and the high ratio of saplings to trees (Table 2.8) probably are results of past logging activity. The low ratio of seedlings to saplings and the low ground flora biomass reflect the present heavy grazing pressure. The shift in dominance of saplings and seedlings (to blackjack oak-post oak) suggests a successional forest. The staff believes this stand to be in an earlier successional stage than is the mesic upland woods (see also Sec. 5.6.1.2), rather than the converse as suggested by the applicant.

• Prairie Hay--There are two moderately large stands of this association (little bluestem-Scribner's panicum-big bluestem) on the BFS site. The high biomass (Table 2.8) and the species composition (Appendix G) suggest that these stands are the least disturbed of the BFS biotic communities (see also Sec. 5.6.1.2). At present, the only disturbance is an annual harvesting of hay.

• Lowland Unimproved Pasture--This association (beaked panicum-sedges-Japanese brome, see Appendix G) is represented by what is virtually a single stand. The species composition (Appendix G) is indicative of grazing disturbance, but the high biomass (Table 2.8) suggests that this stand is not very disturbed (see also Sec. 5.6.1.2).

• Upland Pasture--There are a few large stands of this forb-dominated association (Appendix G). Both the species composition (Appendix G) and the biomass data (Table 2.8) suggest a high degree of disturbance.

• Lowland Improved Pasture--This "association" is a wholly artificial, man-made ecosystem. The only species with a relative cover of more than 3% was Bermuda grass (93% cover), and of the five species with frequencies greater than 50%, two are planted (Appendix G).

• Other Associations--Five stands of riparian (riverine) woods cover a total of 42.6 acres (1.9% of site). These associations are typically very important to wildlife, supporting a higher wildlife diversity than any other association. The applicant did not sample the vegetation of any of the riparian woods stands.

Moist tall grass or sedge meadows occur wherever streams cross relatively undisturbed grasslands. The staff predicts that these associations would have a higher diversity of plants than the surrounding grasslands because of the inclusion of grassland species and of water-tolerant marshland species. No data are available for this association on the BFS site.

Shrub and tree-invaded grasslands cover a total of 117.4 acres (5.3%) of the BFS site. Staff observations at the site suggest that these stands are successional transitions from prairie to woods. The applicant did not sample any of the numerous small stands of this type.

There is a single stand of "scattered conifers" on the Verdigris River floodplain within the BFS site boundary. This is shown on the topographic map as a marsh and may be the recharge point for an aquifer in the floodplain alluvium (see Sec. 4.1.2.1), but there are no data available from this stand.

The remainder of the BFS site (15.4 acres, or 0.7%) is occupied by agricultural fields, fallow land, residential buildings and land, and open water.

### 2.7.1.2 Fauna

The faunal species that are important to the BFS site ecosystems because of their dominance are shown in Appendix G.

Although the BFS site has many ponds (43.3 acres, 2.0% of site), there is little use of the site by waterfowl. Only two species, blue-winged teal and ring-necked duck, were represented by more than ten bird use-days (24.5 and 12.5 bird use-days, respectively) during the 1974 spring migration. Nine species were observed during this study period. By contrast, at the nearby Fort Gibson Wildlife Refuge, 16 species were recorded on one-day winter counts in 1972-73 and in 1973-74. Approximately 60% of the species were represented by more than 500 individuals and 33% by more than 1000 individuals. Two species (snow goose and mallard) exceeded 10,000 individuals.

The game species on the BFS site are shown in Table 2.9.

Table 2.9. Game Species Utilizing BFS Site

| Species | Abundance Class |
|---|---|
| Mammals | |
| Eastern cottontail rabbit | Common |
| Gray squirrel | Common |
| Fox squirrel | Common |
| Raccoon | Common |
| White-tailed deer | Uncommon |
| Beaver | Common |
| Muskrat | Common |
| Striped skunk | Common |
| Birds | |
| Bobwhite | Uncommon |
| Mourning dove | Uncommon |
| Turkey | Observed[a] |
| Reptiles and amphibians | |
| Common snapping turtle | Common |
| Bullfrog | Common |
| Northern copperhead | Com[illegible] |

[a]Status undetermined.

Four species observed on the BFS site are of unusual ecological interest. The nine-banded armadillo, fulvous harvest mouse, and eastern harvest mouse represent the first observed sightings (1974) of these species in Rogers County; however, only the eastern harvest mouse sighting represents a true range extension. The fourth "interesting" species is the savannah sparrow, which winters on the BFS site, and according to the applicant exhibits winter homing (ER Sec. 2.2.3.1, p. 2.2-60).

The rare and endangered species[7] which have not been observed at the BFS site but potentially could utilize the BFS site are listed in Table 2.10. Of these, the only species that appear to have any realizable potential for site utilization are the greater prairie chicken and southern bald eagle (see Secs. 4.3.1 and 5.6.1). The unique habitats on the BFS site are further discussed in Section 5.6.1.

Table 2.10. Rare and Endangered Fauna

| Species | Remarks |
|---|---|
| Greater prairie chicken[c] (*Tympanuchus cupido*) | A booming ground is within 5 miles of BFS. |
| Whooping crane (*Grus americana*) | 1955[a] - Wagoner Co., 1963[a] - Rogers Co. Migratory pathway may cross transmission lines. |
| Southern bald eagle (*Haliaeetus leucocephalus leucocephalus*) | 1950[a] - Wagoner Co. Former resident of area. Potential nesting habitat exists at BFS. |
| Eskimo curlew (*Numenius borealis*) | 1963[b], 1948[a] - Osage Co. |
| Prairie falcon (*Falco mexicanus*) | 1939[a]. Breeds in Western Oklahoma. |
| Peregrine falcon (*Falco peregrinus*) | 1952, 1955[a]. |
| Ivory-billed woodpecker (*Campephilus principalis*) | 1852[a]. Not presently known in U. S. |
| Red-cockaded woodpecker (*Dendrocopos borealis*) | 1934[a]. No nesting habitat in Tulsa area. |

[a]Last sighting in area.

[b]Last known sighting of species anywhere.

[c]Not presently on Federal nor Oklahoma lists. The Atwater subspecies of Texas is the protected bird.

## 2.7.2 Aquatic

### 2.7.2.1 General Aspects

Surface waters in the site vicinity consist of the Verdigris River and Inola Creek, with approximately 30 small ponds on the site proper. Site surface waters and primary biotic sampling stations are shown in Figure 2.15.

The Verdigris River carries a moderate to heavy load of dissolved and suspended solids, organic pollutants, and debris (ER, p. 2.2-80 and Table 2.4-2). Complete mixing of the river water is maintained by natural turbulence except during occasional low-flow periods when some temperature and chemical stratification occurs.

Inola Creek is a small intermittent stream that crosses the southeastern portion of the site (Fig. 2.15). Stagnation can develop in late summer, resulting in dissolved oxygen levels below 4 ppm. High turbidity and high temperatures also occur during portions of the year (ER, p. 2.4-17).

The 30 onsite ponds receive runoff from fertilized hay meadows, and cattle feces are deposited in or near the ponds. Both factors contribute to high nutrient loading. Additionally, the largest pond is polluted by garbage (ER, p. 2.2-83). Wide temperature fluctuations and high turbidity are common to the ponds (ER, Tables 2.4-5 through 2.4-7).

The ecology of the aquatic environments is discussed in some detail in the ER, Section 2.2.3.2. That information provides the basis for the summary of the aquatic ecology given below.

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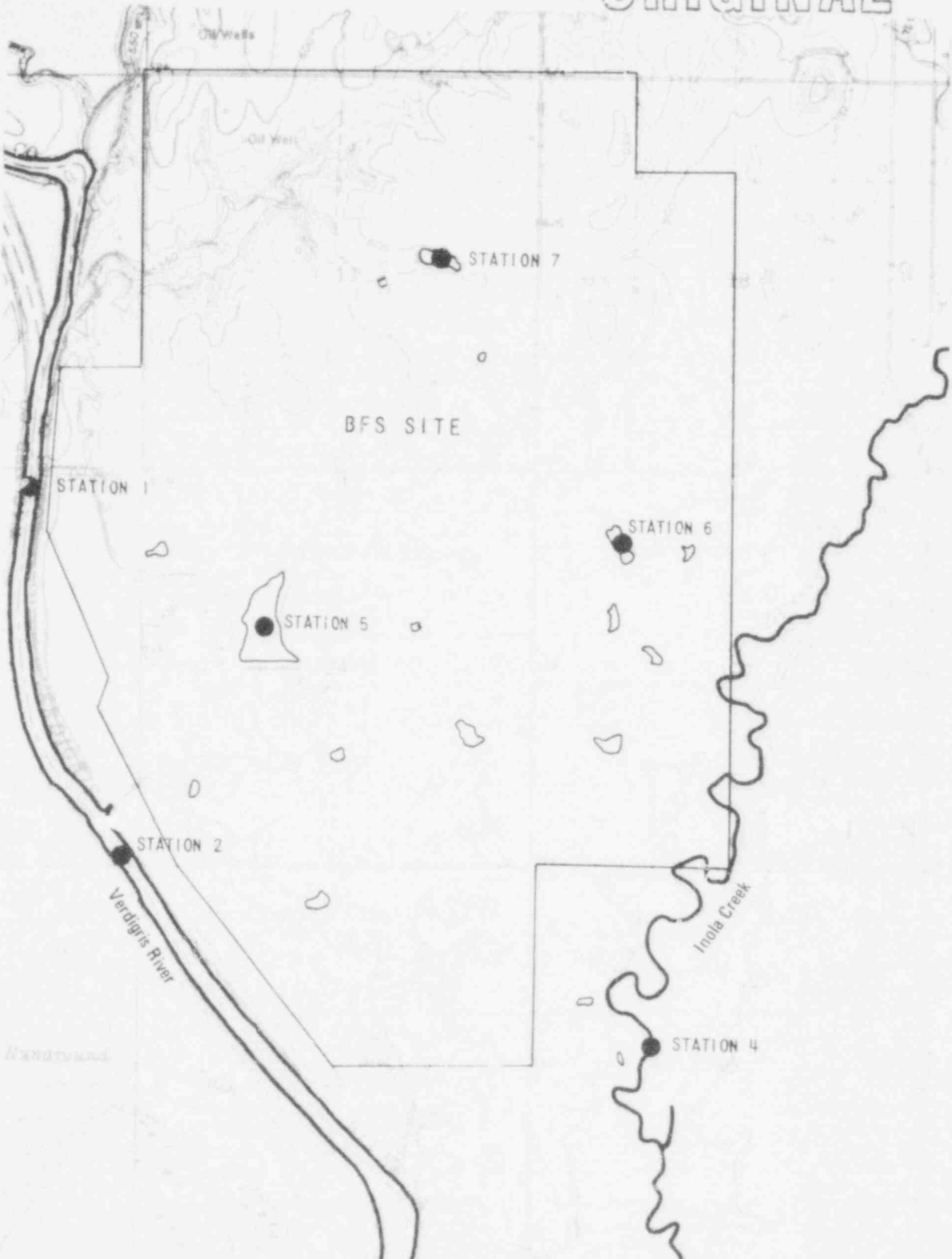



Fig. 2.15. Surface Waters in the Site Vicinity and Aquatic Stations Sampled during 1974. From ER, Fig. 2.4-1.

2.7.2.2 Fish

Fish were collected at the primary sampling stations on the Verdigris River, in backwater areas near Rocky Point Public Use Area, in the backwater area north of Newt Graham Lock and Dam, and in the main channel above and below the dam (Fig. 2.16). A variety of collection methods were used, but most collections were by electrofishing, seining, and various netting methods. A description of techniques and areas sampled can be found in the ER, Section 6.1.1.2.6, and in Section 6 of this Statement.

The fish in the Verdigris River are tolerant of high turbidity, high dissolved solid concentrations, and a wide range of temperatures. The gizzard shad, a forage fish, is the most abundant species (ER, Table 2.2-108). Gizzard shad are eaten by many other Verdigris River fish, including channel and blue catfish, various species of sunfish, gar, freshwater drum, and white crappie. Twenty-six species of fish representing 11 families were collected during seven sampling periods from February 1974 to April 1975.

Except for the gizzard shad and freshwater drum, few fish were found by the applicant in the main channel of the river (ER, Table 2.2-109). This scarcity was attributed to the swift current and turbulence, habitat destruction that has resulted from channelization, and the general paucity of food organisms (benthos and zooplankton) (ER, p. 2.2-81). Backwater areas of the Verdigris appear to support six to ten times as many fish as the main channel (ER, p. 2.2-140 and Table 2.2-109).

Primary sport fishes in the Verdigris River include largemouth bass; white bass; white crappie; channel, blue and flathead catfish; and sunfish. Most sport fishing is limited to backwater regions such as the Rocky Point Public Use Area (Fig. 2.16; ER, pp. 2.1-15, 2.2-107, and 2.2-109). Since channelization there has been no commercial fishing in the river.

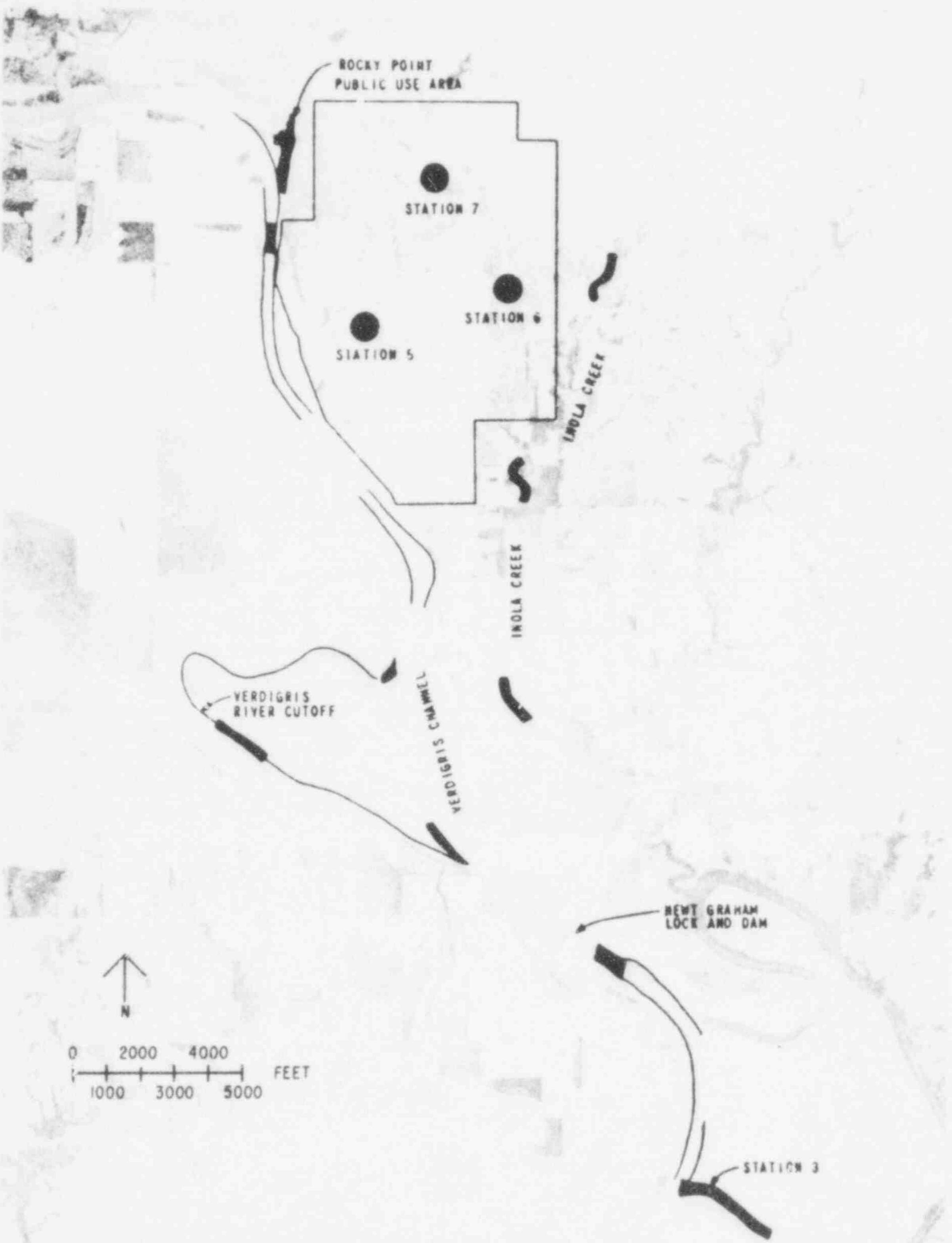
Fish populations in the Inola Creek are dominated by green sunfish, longear sunfish and black bullheads. Carp, white crappie, bluegill, and largemouth bass are also found in sufficient numbers to support limited sport fishing in the creek (ER, p. 2.2-148 and Table 2.2-112). In general, the fish of Inola Creek are either capable of tolerating low dissolved oxygen levels or can migrate to other areas of more suitable habitat during periods of stagnation.

The onsite ponds are generally populated by sunfish, gizzard shad, golden shiners, and black bullheads. The deeper ponds also contain largemouth bass, bigmouth buffalo, and white crappie (ER, Tables 2.2-114 through 2.2-116). Overpopulation, with resultant stunting, is common in most of the ponds. The fish in the ponds are generally adapted to high turbidity and wide temperature fluctuations. The largest onsite pond (Aquatic Station 5 in Fig. 2.15) is the major fishing pond in the vicinity. Overpopulation-induced stunting limits potential angling in the other ponds (ER, p. 2.2-150).

In 1974 and 1975 fish eggs and larvae were sampled at the three Verdigris River primary sampling stations and two backwater areas (Rocky Point Public Use Area and the area north of Newt Graham Lock and Dam). The applicant's sampling efforts for May 1974 through March 1975 resulted in collection of a total of only 63 fish larvae (includes fish labeled "juveniles") and 12 fish eggs (ER, Tables 2.2-122 and 2.2-123). Forty-two of the larvae were collected in the backwater areas and the rest in the main channel; 10 of the 12 fish eggs were collected in the main channel. In most of the samples, no larvae or eggs were collected. The highest concentrations sampled were on May 23, 1974--15.3 larvae per 10,000 liters of water at the Rocky Point backwater area, and 8.7 eggs per 10,000 liters at Station 1 in the main channel. From February 1975 through July 1975, additional sampling was performed in the area of the proposed intake to obtain more definitive information on fish eggs and larvae in the Verdigris. This sampling, performed in the area of the proposed intake, did result in collection of many more fish larvae and eggs (ER, Table 0-2.45-4). From May through July, 1547 larvae and 157 eggs were collected, although number of organisms per unit volume of water were low. Maximum values obtained were only 12.0 larvae per 10,000 gallons (3.2 per 10,000 liters) on May 22, 1975, and 1.2 eggs per 10,000 gallons (0.32 per 10,000 liters) on June 10, 1975.

2.7.2.3 Benthic Macroinvertebrates

The benthos was disturbed when the Corps of Engineers channelized the Verdigris River and built the Newt Graham Lock and Dam. Present benthic populations are limited in the Verdigris by scouring due to turbulence and by agitation caused by barge and pleasure boat traffic. As a result, the benthic macroinvertebrates near the site vicinity occur primarily as drift (ER, p. 2.2-81). Nevertheless, macroinvertebrates such as mayflies, caddisflies, dipterans, oligochaetes, and molluscs occur in the river. Sampling in 1974 revealed mayfly, caddisfly, and midge larvae to be the predominant organisms. A detailed listing and analysis of the benthic invertebrates collected in the Verdigris is given in the ER, Tables 2.2-95 through 2.2-98. The benthic organisms in the river exhibit relatively broad tolerances to various environmental stresses, particularly those associated with organic enrichment. Furthermore, the life cycles of the




SINGLE LINES INDICATE BOOM SHOCKING TRAVERSES. HEAVIER MARKINGS INDICATE AREAS WHERE NETS AND OTHER SAMPLING PROCEDURES WERE EMPLOYED.

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Fig. 2.16. Fish Sampling Locations. From ER, Fig. 6.1-2.

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mayflies and caddisflies are timed in such a manner that extremes of conditions are avoided, e.g., adult emergence during periods of low dissolved oxygen, reduced flow, and high temperatures (ER, p. 2.2-128).

Inola Creek contains numerous benthic mac vertebrates (ER, Tables 2.2-95 and 2.2-99). The predominant organisms are tubificid worms, sphaeriid clams, mayfly naiads, and chironomid larvae. The benthic fauna of Inola Creek, as a whole, is composed largely of organisms that are well adapted to an existence in silt-laden waters with some degree of organic enrichment (ER, p. 2.2-132).

Benthic organisms, including clams, snails, crayfish, and aquatic insects, such as dragonflies, mayflies and dipterans (ER, Tables 2.2-101 through 2.2-103), are also abundant in the shallower waters of the small onsite ponds where stratification does not occur. The benthos of the anaerobic portions of the ponds is dominated by those taxa that can withstand low oxygen levels, such as the oligochaetes and chironomids.

### 2.7.2.4 Zooplankton

During several months of 1974, a number of zooplankton species were collected at primary biotic sampling sites (Fig. 2.15 and ER, Tables 2.2-87 through 2.2-89).

Several species of rotifers, protozoans, cladocerans, and copepods were found in the Verdigris River. Only limited secondary production of zooplankton, along with low primary production, was observed.

In Inola Creek, 25 rotifer species and 13 cladoceran taxa were identified. In addition, there were six species of copepods and two of protozoa (ER, Tables 2.2-86 and 2.2-90).

Abundant zooplankton populations were found in three sampled onsite ponds, a condition apparently resulting from the availability of sufficient foods (algae, detritus, and other zooplankton). Rotifers, copepods, and cladocerans were the most dominant zooplankton. Their relative abundance varied among ponds and among sampling periods within a given pond (ER, Tables 2.2-91 through 2.2-93).

### 2.7.2.5 Phytoplankton

The Verdigris River supports only a sparse assemblage of phytoplankters, composed primarily of pollution-tolerant diatoms (ER, Table 2.2-85). The zone of primary productivity is severely limited in depth by turbidity. Furthermore, turbulence prevents the algae from maintaining a position within this narrow photic zone. Species characteristic of the main channel near the site are shown in the ER (Tables 2.2-66 through 2.2-69 and 2.2-78 through 2.2-79). The diatoms were dominant during 1974, except in August at Station 1, when *Euglena* sp. became dominant. By October the diatoms had regained dominance.

The phytoplankton species collected below the Newt Graham Lock and Dam (Station 3) are listed in the ER (Tables 2.2-70 and 2.2-80). Diatoms were dominant.

In Inola Creek the diatoms were strong dominants throughout 1974 (ER, Tables 2.2-71, 2.2-72, and 2.2-81). In the latter part of 1974 there were relatively more blue-green, green and euglenoid algae, but none of these became dominant. In general, the phytoplankton were limited by fluctuations in flow and discharge, coupled with high turbidity and excessive shading. As a result of substrate scouring, many of the organisms reported as phytoplankton were actually periphyton species in the water column. Since seven of Palmer's[8] 20 most tolerant algal species occur in the creek, probable organic pollution is indicated.

A diverse phytoplankton community was present in the three ponds sampled (ER, Tables 2.2-74 through 2.2-76). Highest phytoplanktonic productivity occurred in the ponds with the greatest light transmission. High turbidities at all stations tended to limit productivity (ER, p. 2.2-97). Of the 60 most tolerant genera of algae and 80 most tolerant species listed by Palmer,[8] 32 genera and 20 species occurred at Station 5 (ER, Tables 2.2-73 and 2.2-74), indicating probable organic pollution. Phytoplankton were most abundant in February in one of the ponds (Station 6) and declined steadily over the spring and summer because of turbidity resulting from strong winds and wading by cattle. Many of the most pollution-tolerant species of algae occurred in this pond. Another pond (Station 7) had the most diverse phytoplankton community (ER, Table 2.2-77) because it is protected from most high winds and turbulence is infrequent. Although several pollution-tolerant phytoplankton species occur in the pond, the high species diversity and equitability values indicate the pond is a rather well-balanced system (ER, p. 2.2-108). Lower diversity values and the presence of pollution-tolerant forms in the other ponds (Stations 5 and 6) indicate that they are stressed environments.

#### 2.7.2.6 Periphyton

Artificial substrata made of Plexiglas plates revealed the periphyton community of the Verdigris River to be composed mainly of pollution-tolerant diatoms, with relatively few green or blue-green algae (ER, Table 2.2-65). Diatoms were dominant at Stations 1 and 2 from April 1974 to January 1975 (ER, Tables 2.2-48, 2.2-49, 2.2-55, and 2.2-56). Although periphyton from Station 3 reflected some quantitative differences from Stations 1 and 2, the dominants were similar at all locations. Though abundant growth was observed on these artificial periphyton samplers, the continual erosion of the channel's clay banks probably limits the amount of natural substratum available for periphyton development.

The bulk of primary productivity in Inola Creek was contributed by the periphyton (ER, p. 2.2-81). Diatoms were usually dominant, although mats of green algae occurred occasionally. Blue-green algae were dominant in March 1974. The number and relative abundance of each species found is given in the ER, Table 2.2-51, with comparisons of periphyton assemblages by groups in ER Table 2.2-58.

The periphyton of Station 6, a small, shallow and turbid pond, was composed primarily of pollution-tolerant diatoms, in contrast to the green algae of Station 5. At Station 7, diatoms accounted for 67% of the total periphyton, while green algae comprised the remaining 33%. Numbers of individuals of species encountered and their relative abundance for the onsite ponds are listed in the ER, Tables 2.2-52 and 2.2-53, with comparisons of periphyton assemblages by groups given in Tables 2.2-59 through 2.2-61 of the ER.

#### 2.7.2.7 Macrophytes

Opportunistic collections of macrophytes were made during all sampling periods. Macrophyte development is very restricted in the Verdigris River and sparse in Inola Creek due to periodic scouring by floods. Additional factors limiting macrophyte growth are strong currents and waves induced by wind and barge traffic in the Verdigris, and excessive shading and poor substrate in Inola Creek. A few species of aquatic macrophytes exist in backwaters and shallow areas of the river, especially in the areas of silt deposition. The most prolific growth of macrophytes occurred in the shallow areas of the onsite ponds. The greatest primary production in these ponds is accomplished by the macrophytes *Justicia americana* and *Ludwigia repens*. The aquatic macrophytes identified during 1974 are listed in Table 2.2-46 of the ER. The areal coverage of aquatic macrophytes in the onsite ponds is shown in the ER, Figures 2.2-47 through 2.2-49.

#### 2.7.2.8 Rare and Endangered Species

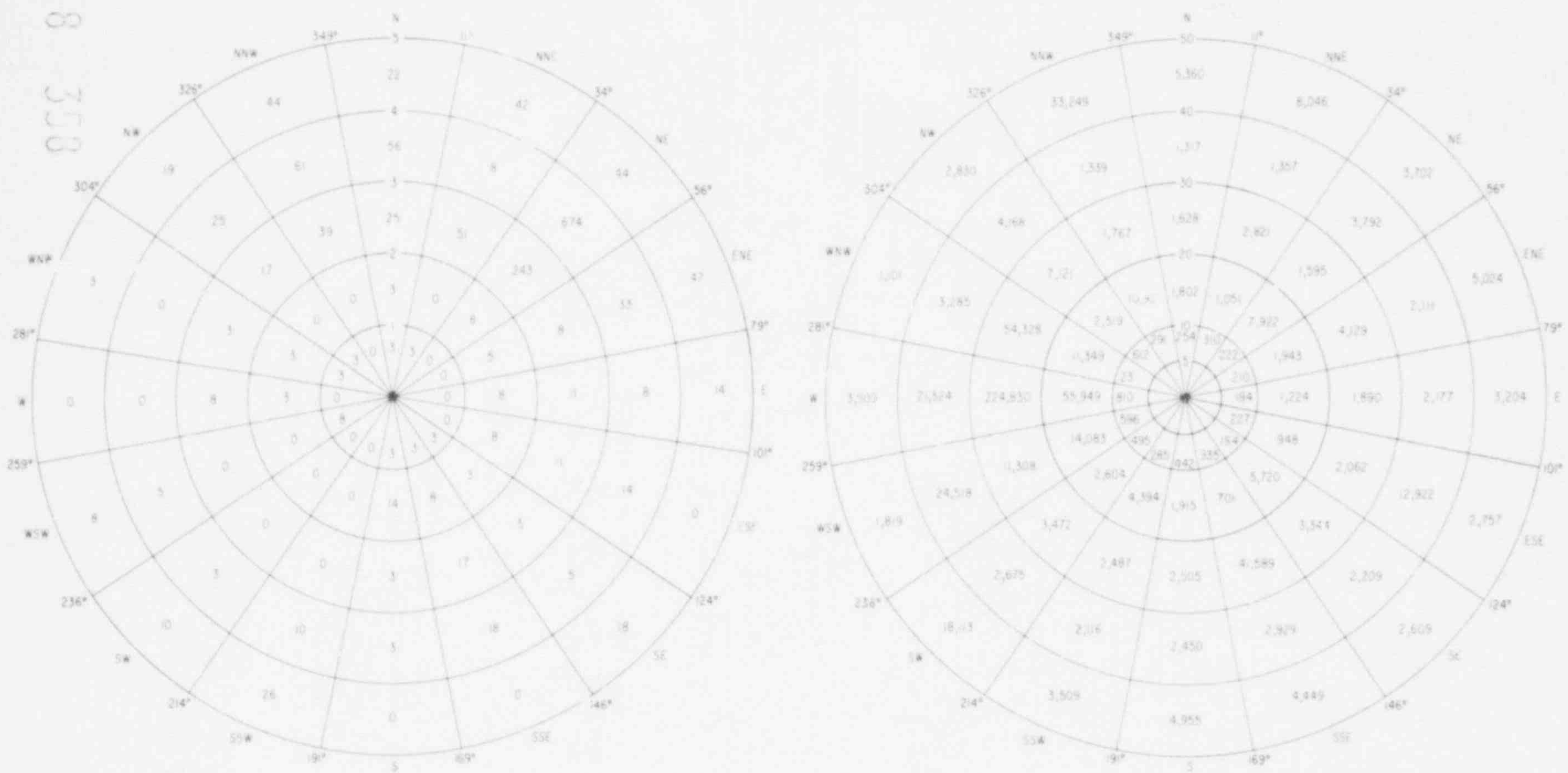
None of the fish species collected or potentially occurring in the vicinity of the Black Fox Station (ER, Table 2.2-107) is listed as endangered or threatened in the United States.[7,9] The highfin carpsucker, *Carpiodes velifer*, could be present, but was not collected by the applicant in the Verdigris. It is listed as "Rare-2" (species that may be quite abundant where it does occur but is known in only a few localities or in a restricted habitat) in Oklahoma.[10] Two individuals of goldeye, *Hiodon alosoides*, were collected by the applicant. This species is listed under the category of "status undetermined" (species suggested as possibly rare or endangered, but about which there is not enough information to determine its status) in Oklahoma.[10] Though not listed as potentially occurring in the BFS vicinity, the Kiamichi shiner (*Notropis ortenburgeri*) was collected in the Verdigris River in 1958.[11] This species is listed as a "Rare-2" in Oklahoma.[10] The Kiamichi shiner is generally located in the Kiamichi River, Little River system, and Poteau River of the Arkansas River system. It has not been collected since 1958 in the Verdigris and, thus, may have only been found in the river due to bait release.

## 2.8 SOCIAL PROFILE

### 2.8.1 Demography

The proposed site is in a predominantly rural area of low population density. The nearby population of Inola grew from 584 in 1960 to 948 in 1970. There are three other communities within ten miles: Fair Oaks (1970 population of 23), New Tulsa (17), and an unincorporated community, Taiwah, with 95 people (ER, Table 2.1-8). The urban center of the Tulsa metropolitan area is about 23 miles west of the site. Its population was 330,409 in 1970.

The applicant estimates that in 1970 approximately 1753 people lived within a five-mile radius of the proposed site, and about 5500 within ten miles. The spatial distribution of 1970 population within 50 miles is shown in Figure 2.17. The applicant's population projections for the areas within the 10- and 50-mile radii of the proposed site are given in Tables 2.11 and 2.12.




(a) (b)

| Annulus (miles) | 0-1 | 1-2 | 2-3 | 3-4 | 4-5 | 0-10 | 10-20 | 20-30 | 30-40 | 40-50 | 0-50 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Population Density (per square mile) | 9.2 | 6.7 | 28.1 | 42.1 | 10.5 | 23.1 | 133.0 | 233.6 | 41.5 | 36.9 | 88.4 |

Fig 2.17. 1970 Population Distribution within (a) Five Miles and (b) 50 Miles of the BFS Site. (Based on figures from the ER, Table 2.1-2.)

Table 2.11. Population within Ten Miles of the BFS Site, 1970-2020

| Year | Radius (miles) | | | | | | 10-Mile Total |
|---|---|---|---|---|---|---|---|
| | 0-1 | 1-2 | 2-3 | 3-4 | 4-5 | 5-10 | |
| 1970 | 29 | 63 | 441 | 923 | 297 | 5,500 | 7,253 |
| 1983 | 0 | 213 | 1693 | 1771 | 533 | 8,416 | 12,626 |
| 1990 | 0 | 232 | 1768 | 1946 | 629 | 9,997 | 14,572 |
| 2000 | 0 | 308 | 2327 | 2465 | 801 | 12,275 | 18,176 |
| 2010 | 0 | 348 | 2525 | 2706 | 958 | 14,469 | 21,006 |
| 2020 | 0 | 391 | 2677 | 2915 | 1124 | 16,774 | 23,881 |

From ER, Table 2.1-1.

Table 2.12. Population within 50 Miles of the BFS Site 1970-2020

| Year | Radius (miles) | | | | | 50-Mile Total |
|---|---|---|---|---|---|---|
| | 0-10 | 10-20 | 20-30 | 30-40 | 40-50 | |
| 1970 | 7,253 | 125,055 | 366,866 | 90,889 | 104,236 | 694,299 |
| 1983 | 12,626 | 150,458 | 394,946 | 104,915 | 115,909 | 778,854 |
| 1990 | 14,572 | 182,559 | 482,648 | 115,162 | 119,447 | 914,388 |
| 2000 | 18,176 | 214,832 | 550,144 | 130,221 | 128,962 | 1,042,335 |
| 2010 | 21,006 | 246,051 | 616,736 | 145,563 | 138,197 | 1,167,553 |
| 2020 | 23,881 | 277,886 | 677,741 | 159,912 | 147,227 | 1,286,647 |

From ER, Table 2.1-2.

Within the 50-mile area, the cumulative population growth is the highest in the 20- to 30-mile zone, reflecting the urban population cluster of Tulsa with a 1970 census population density of 701 persons per square mile. As calculated by the staff, the projected annual growth rate within a 10-mile radius is 4.3% during the period 1970 to 1983. The projected growth rate within a 20-mile radius (estimated on the basis of the applicant's data) is 1.6% during the same period.

The transient population within five miles of BFS includes school and church attendees, commercial and industrial employees, recreational facility employees and users, and people attending public events at facilities along Highway 33. The locations of these facilities are shown in Figure 2.18.

The peak transient population is expected to occur on summer Sundays, with average Sunday population during the summer season projected to be 4290 by 1983 and 6230 by 2020, excluding BFS construction and operation workers (ER, p. 2.1-5).

### 2.8.2 Community Characteristics

Presently, the area within ten miles of the proposed site is predominantly rural and includes parts of Rogers, Wagoner and Mayes Counties. The community of Inola, the largest in the area with a 1974 population of 1176,[13] had grown rapidly during the last two census periods. Its population increased over 60%, while the statewide rural population decreased by over 5% during the same period.[12]

In the town of Inola and the vicinity of the proposed site, the unemployment rate was reported to be approximately 21% in 1972. Per capita annual income was estimated to be $2400, which is lower than average per capita annual income in Rogers County and in the Tulsa area by approximately $1000 and $1700, respectively.[14] About 64% of the area's employed people in 1972 were reported to be working in the Tulsa area (ER, p. 8.1-13).

At present, there are only a few small industrial operations within five miles of the proposed site, employing a total of about 36 persons. They include the Inola Farm Elevator Company, Rich

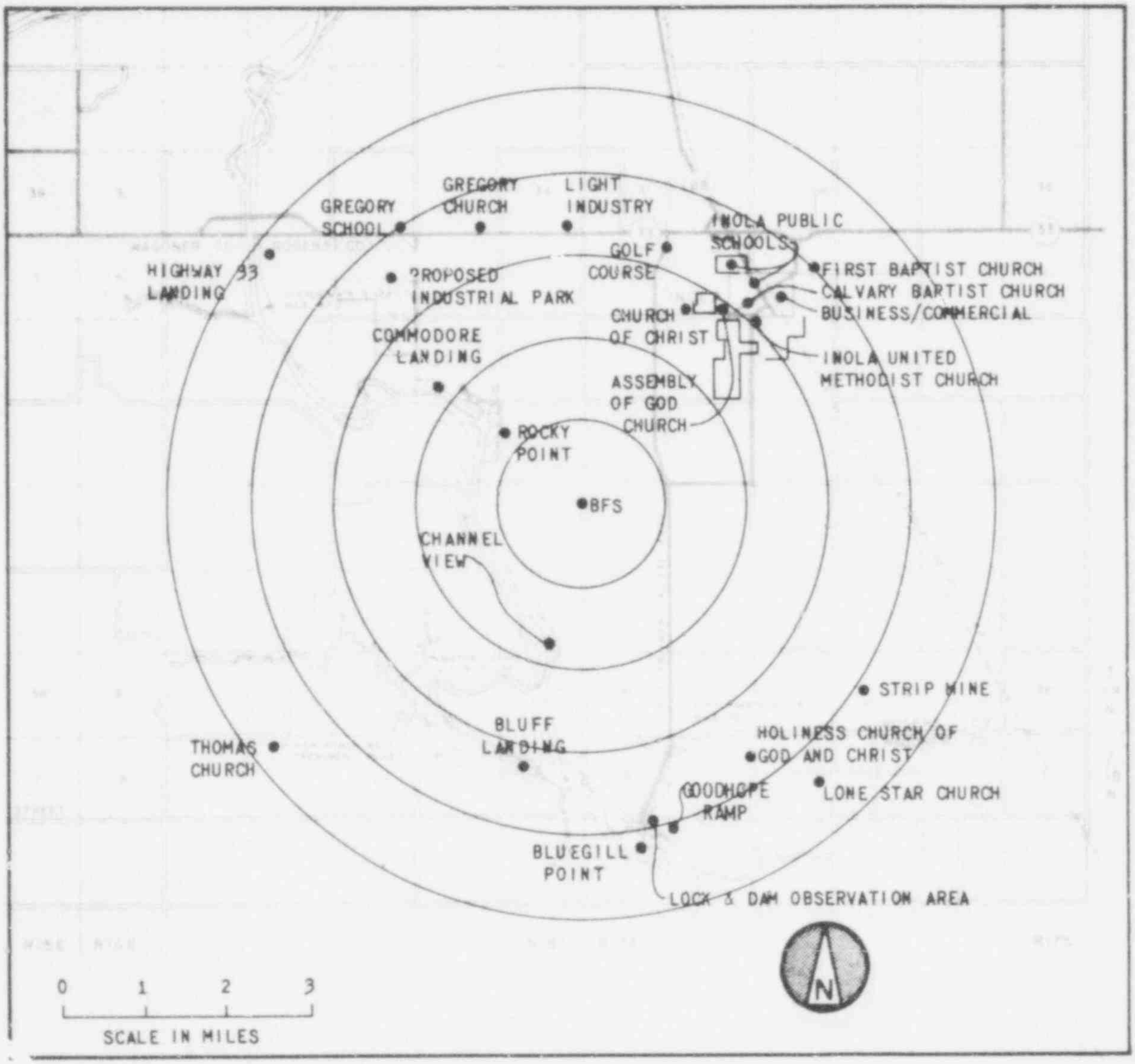



Fig. 2.18. Locations of Offsite Transient Population. From ER, Fig. 2.1-9.

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Mar Corporation, Miller Manufacturing Company, and the United Coal Company. There is an area three miles northeast of the site, adjacent to Highway 33, which has been considered by the Northeast Counties of Oklahoma Economic Association as a possible site for an industrial park location. The staff is not aware of any specific development plans for this location, however. There are substantial mining and oil production activities within 25 miles of the site (ER, Table 9.3-1).

Of the 392 housing units in Inola, most are single-family dwellings (78%) or mobile homes (about 18%), with only about 4-5% multi-family dwellings. There are 192 residential dwellings outside of the site boundary but within three miles of the site complex. Figure 2.19 shows the locations of the residences currently in the site vicinity. Ten residential structures currently stand within the site boundary, six of which will be removed during construction of Unit 1. After BFS is constructed, the nearest residence will be approximately 0.8 mile from the site's southern boundary.

### 2.8.3 Transportation Facilities

State Highway 33, approximately two miles north of the site, is the closest highway. State Highway 88 is three miles northeast of the site, and the Will Rogers Turnpike (I-44) and Musgokee Turnpike are approximately ten miles away. The closest major north-south highway, U. S. 69, is 12 miles east. In addition, two unpaved county roads traverse the site. Average traffic volumes of the major highways are presented in Table 2.13.

Table 2.13. Average Daily Traffic Volumes of Major Highways within Plant Vicinity

| | Average Daily Volume (vehicles) | | | | | |
|---|---|---|---|---|---|---|
| Highway | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 |
| U. S. 69 (Pryor to Wagoner) | 5700 | 6029 | 6257 | 5814 | 5943 | 6200 |
| SH 33 (Tulsa to Inola) | 4500 | 4975 | 4675 | 5000 | 5575 | 6075 |
| SH 88 (I-44 to Inola) | 1125 | 1375 | 1175 | 1100 | 1300 | 1250 |

From ER, Table 2.1-10.

The Missouri Pacific Railroad passes approximately three miles to the east of BFS. Typical traffic is eight trains per day with an average of 63 cars per train. The applicant plans to construct a rail spur connecting the site to the mainline, one mile south of Inola.

In 1974, approximately 560 barge tows (consisting of three to five barges each) traversed the Verdigris River navigation channel. Pipelines for oil and gas are located northwest of the site in northeast-southwest orientation. The closest is four miles from the site and is operated by Continental Pipeline Company. The nearest commercial airport is in Tulsa.

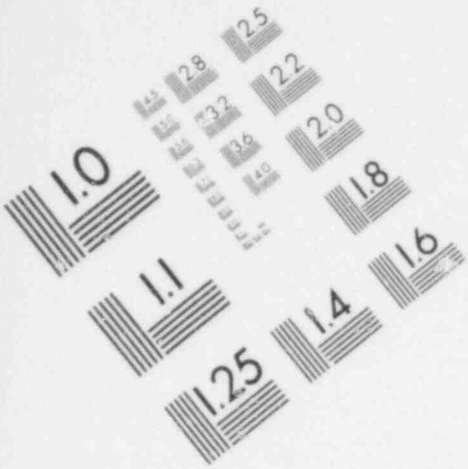
## 2.9 REGIONAL LANDMARKS

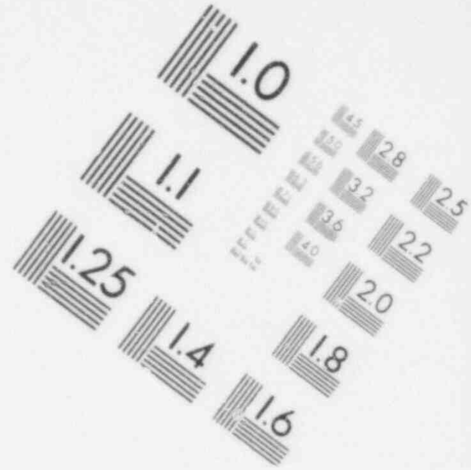
There are several areas of cultural/historic importance on the station property and in the nearby vicinity. The applicant has contacted the Oklahoma State Historic Preservation Officer in regard to these sites (see Appendix B). See also discussion of staff's requirements in Section 4.1.3.

### 2.9.1 Historic Sites

One historic cemetery is located in the southern portion of the site and two others are in the immediate vicinity of the property (ER, p. 2.6-9). These cemeteries are believed to be Negro-Creek Indian cemeteries that date from the late 19th Century to the present (ER, p. 2.6-10).

There are no sites recorded in the National Register of Historic Places on or within a ten-mile radius of the station (ER, p. 2.6-11). However, three historic mission sites and the homestead of Will Rogers are within 10 to 25 miles of the station, and all are recorded in the Register (ER, p. 2.6-12). The Oklahoma Historical Society lists 17 additional sites for the area included





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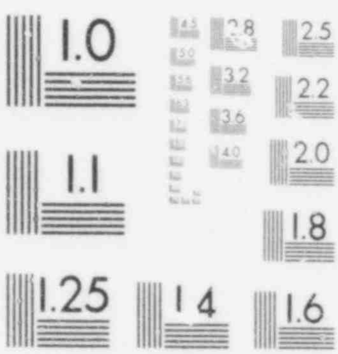


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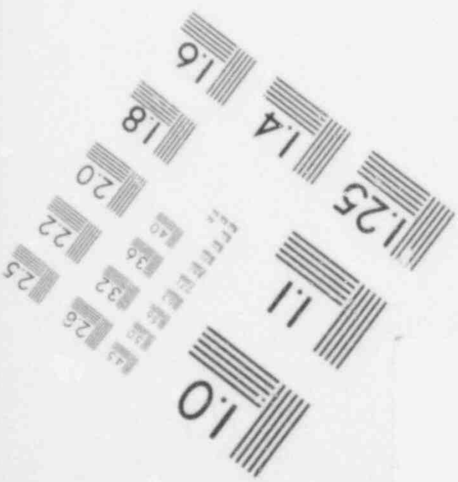

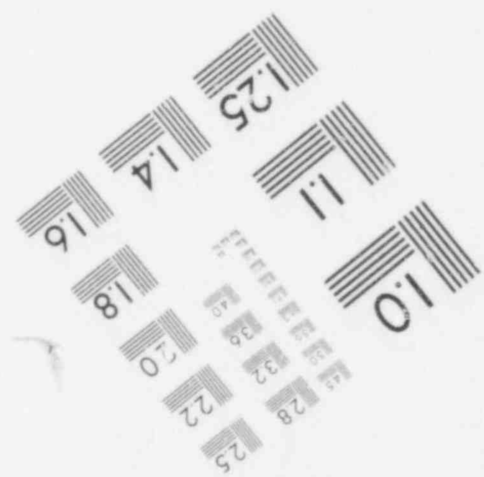

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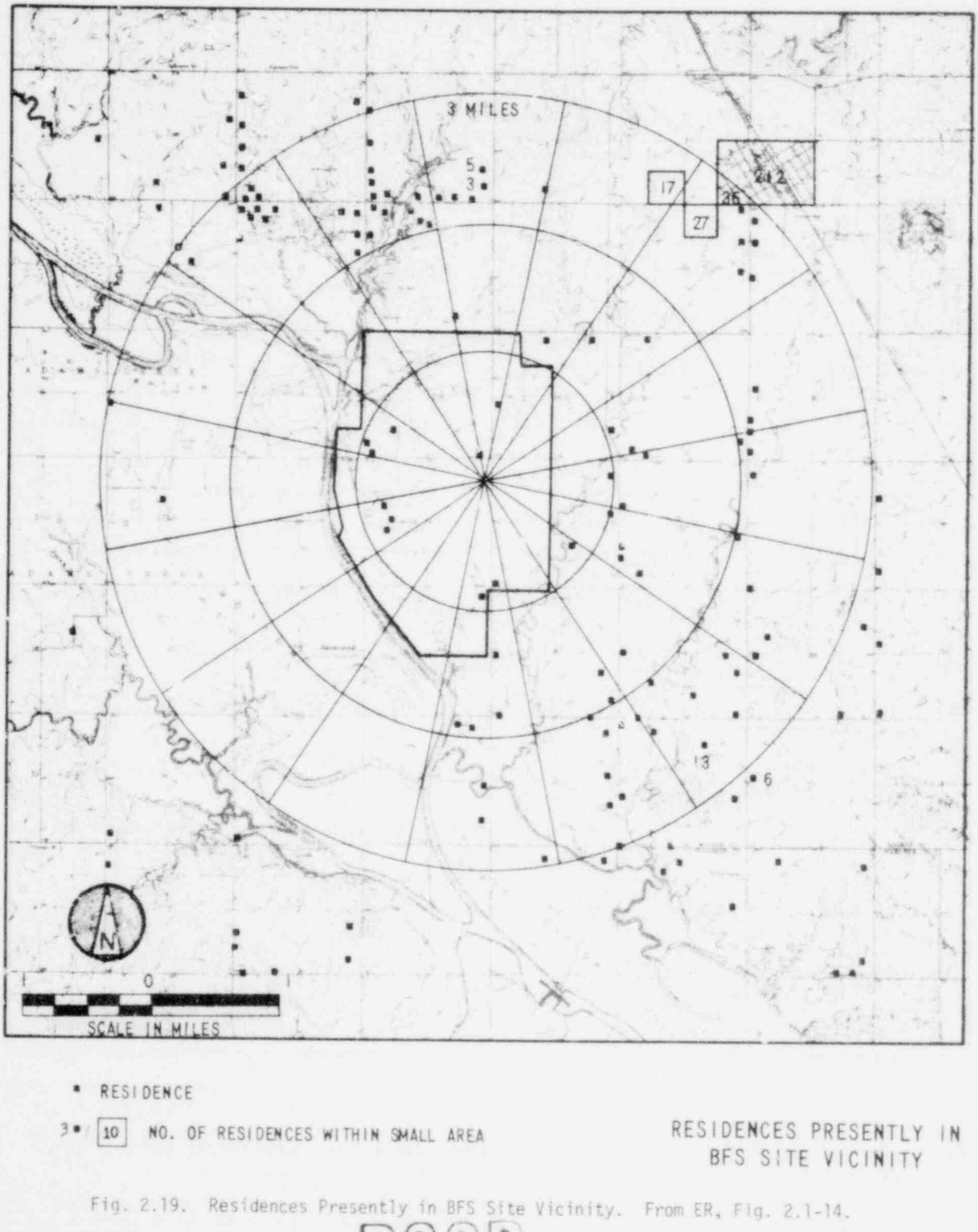


Fig. 2.19. Residences Presently in BFS Site Vicinity. From ER, Fig. 2.1-14.

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in the 10- to 25-mile radius (ER, pp. 2.6-12 and 2.6-13). These sites include historic Indian villages, graves of historically important people, battlegrounds, and early town sites (ER, pp. 2.6-12 and 2.6-13). The applicant has contacted the State Historic Preservation Office concerning historic sites on or in the vicinity of the site (see Appendix B).

### 2.9.2 Prehistoric Sites

Two archeological surveys were conducted on and near the station (ER, p. 2.6-6). Three archeological sites were identified on the station property and three others were recorded within one mile of the station boundary (ER, p. 2.6-9). Sites on the plant property were small areas with surface-debris and apparently functioned as short-term camps (ER, pp. 2.6-8 and 2.6-9); however, at the present time, insufficient data is available to evaluate their specific functions or values.

### 2.9.3 Scenic and Natural Areas

There are some scenic areas of local significance within five miles of the BFS site. While they may have local value, none has been designated as having state or national significance (ER, p. 2.6-14). Such areas include particular floodplain and hilltop locations, including Snake Den Lake, Inola Hill, Big Bottom, Goodhope Bottom, Quinn Bottom, Brushy Prairie and Snake Den Bluff (ER, Fig. 2.6-6).

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14. "Supplement: Statistical Abstract of Oklahoma 1972," Center of Economic and Management Research, the University of Oklahoma, January 1975.

# 3. THE STATION

## 3.1 EXTERNAL APPEARANCE

Figure 3.1 is an artist's sketch of the proposed Black Fox Station. Each reactor will be housed in a concrete structure with surface treatments to provide a variety of textures. Panels will also be used for this purpose. The station grounds will be landscaped to provide partial screening of equipment and structures such as the station buildings which will be partially hidden from the view of traffic on Oklahoma State Highway 33. The upper parts of the reactor containment buildings will be visible from certain portions of the river. At times, plumes from the cooling towers will be visible from greater distances (Sec. 5.3).

## 3.2 REACTOR, STEAM-ELECTRIC SYSTEM, AND FUEL INVENTORY

The station will consist of two essentially identical units arranged in a side-by-side layout. Each unit will consist of a General Electric Company boiling water reactor (BWR-6/MK III) and steam turbine-generator. The designers for the project are Black and Veatch, Consulting Engineers from Kansas City, Kansas.

Each reactor will be rated at 3579 MWt and 1220 MWe gross (1150 MWe net) power. The fuel will consist of uranium oxide pellets with an average enrichment of 1.72% uranium-235. The fuel will be clad with Zircaloy-2, and some fuel rods will contain a burnable poison, Gadolinia ($Gd_2O_3$), mixed with uranium dioxides as the fuel.

## 3.3 PLANT WATER USE

The main uses of water for BFS will be for steam generation in the reactor-turbine system and for condensing exhaust steam in the system condensers. Water will also be used for cooling other plant equipment, for bearing lubrication and cooling, for various chemical operations, and for domestic, sanitary, and other plant uses. Most of the water used will be recycled so that the plant water intake rate will be far below the amounts of water pumped internally within the plant.

All water used in the plant will be pumped from the Verdigris River. The water will be first pumped to a presettling pond with a storage capacity of approximately 585 acre-feet. In the pond there will be a 140 hour maximum holding time for settling of suspended solids. The maximum and average water intake with both generating units operating is expected to be 28,000 gpm and 22,600 gpm, respectively.

After the settling period, water will be pumped from the pond to the various plant systems. A schematic diagram of the uses is shown in Figure 3.2. The figure is keyed to Table 3.1, which also lists flow rates. The major water-use pathways are briefly described below.

Makeup water for the main condenser cooling system (about 21,900 gpm average) is first pumped through the service water system where it is used to cool auxiliary heat exchanges. Excess water not needed for makeup is returned to the settling pond. Water in the condenser cooling system is recycled between the condensers and cooling towers at a rate of 620,000 gpm for each unit. Normally enough water for about 30 minutes' operation (about 18 million gallons) is contained in the basins and pipes. The average evaporation rate in the cooling towers will be about 19,500 gpm, and blowdown about 2400 gpm, leading to a concentration factor of about nine for the dissolved solids in the entering water. At this concentration factor it will be necessary to add sulfuric acid and possibly scaling inhibitors to prevent mineral deposition in the condenser tubes (see Sec. 3.6.1.1).

## 3.4 HEAT DISSIPATION SYSTEM

### 3.4.1 Circulating Water System

At design power (1220 MWe gross, per unit) the station will produce $1.655 \times 10^{10}$ Btu/hr of waste heat, which will be dissipated to the atmosphere primarily via mechanical-draft cooling towers.

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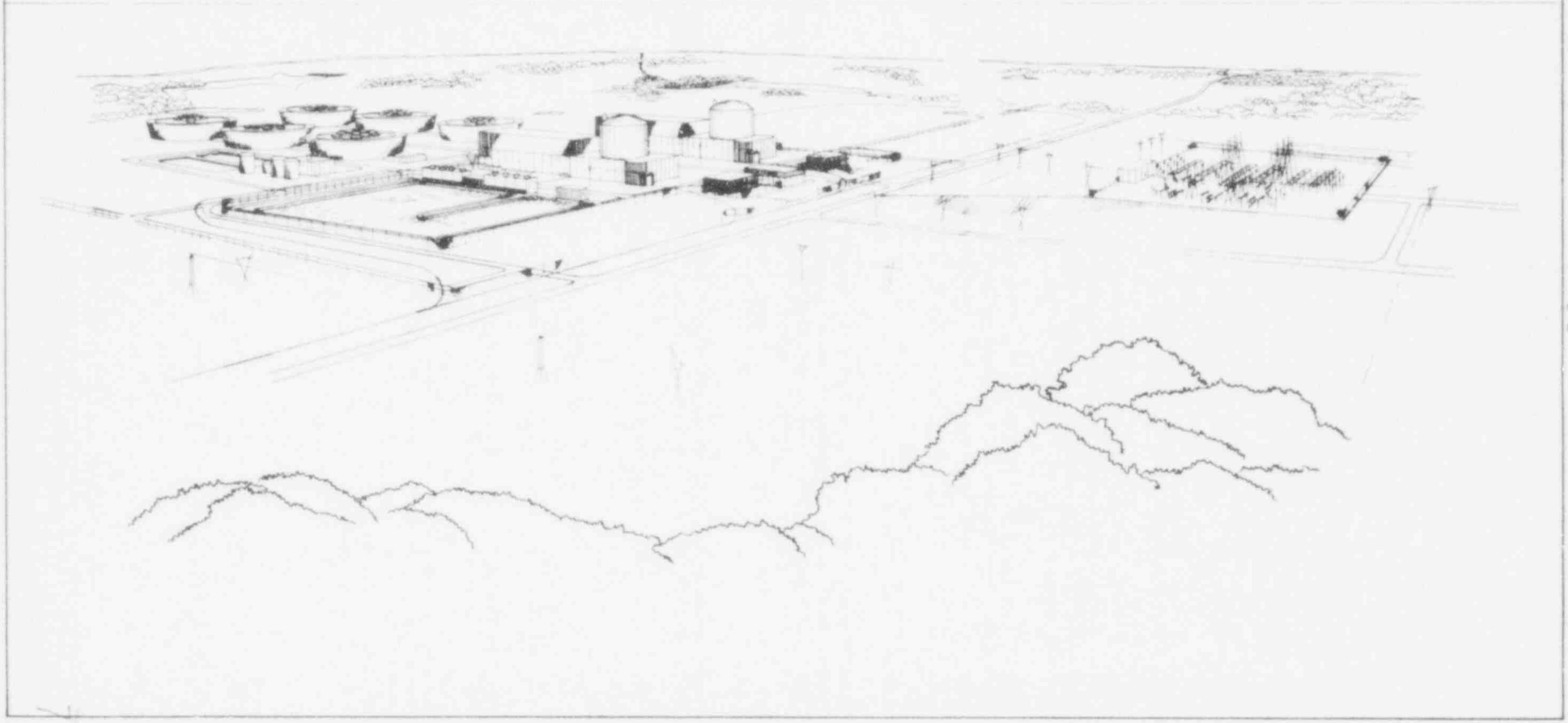

Fig. 3.1. Artist's Sketch of Proposed Black Fox Station. From ER, Fig. 3.1-4.

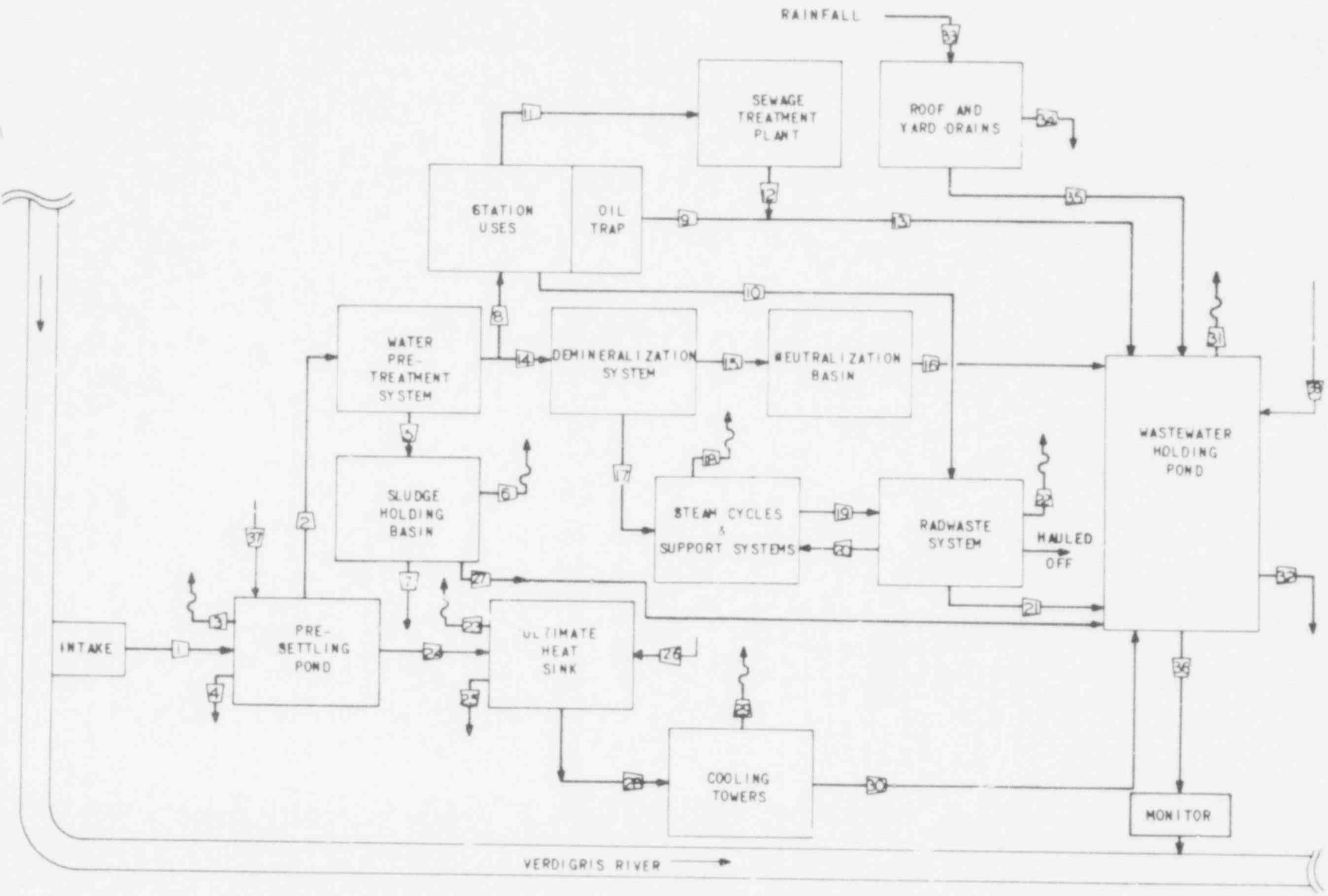


Fig. 3.2. Schematic Diagram of BFS Water Use. (Diagram keyed to Table 3.1.) From ER, Supp. 0, Fig. 3.3-1.

Table 3.1 BFS Water Use[a]

| Stream[b] Number | Description | Expected Maximum Operation[c] (100% load) | Average Operation[c] (80% load) | Temporary One-Unit Shutdown[c] |
|---|---|---|---|---|
| 1 | Makeup water from river | 28,000 | 22,600 | 14,500 |
| 2 | Water pretreatment system makeup | 410 | 380 | 320 |
| 3 | Presettling pond evaporation | 120 | 120 | 120 |
| 4 | Presettling pond exfiltration | 310 | 310 | 310 |
| 5 | Water pretreatment system blowdown | 9 | 9 | 9 |
| 6 | Sludge holding basin evaporation | 1 | 1 | 1 |
| 7 | Sludge holding basin exfiltration | 2 | 2 | 2 |
| 8 | Miscellaneous station uses | 205 | 205 | 205 |
| 9 | Nonradioactive station drains | 200 | 200 | 200 |
| 10 | Radioactive station drains | <1 | <1 | <1 |
| 11 | Sanitary facilities wastes | 5 | 5 | 5 |
| 12 | Sewage treatment plant effluent | 5 | 5 | 5 |
| 13 | Miscellaneous station wastes | 205 | 205 | 205 |
| 14 | Demineralizer makeup | 200 | 200 | 200 |
| 15 | Demineralizer wastes | 21 | 18 | 10 |
| 16 | Neutralization basin effluent | 21 | 18 | 10 |
| 17 | Steam cycle makeup | 180 | 150 | 100 |
| 18 | Steam cycle losses | 180 | 150 | 100 |
| 19 | Radioactive wastes | 35 | 28 | 35 |
| 20 | Reclaimed radwaste | 35 | 28 | 35 |
| 21 | Radwaste system discharge (normal) | 0 | 0 | 0 |
| 22 | Evaporation from radwaste system | <1 | <1 | <1 |
| 23 | UHS evaporation and drift[d,e] | 10 | 10 | 10 |
| 24 | Ultimate heat sink makeup | 27,200 | 21,900 | 13,800 |
| 25 | UHS exfiltration | 53 | 53 | 53 |
| 26 | Rainfall on UHS storage basin | 8 | 8 | 8 |
| 27 | Sludge holding basin decant | 6 | 6 | 6 |
| 28 | Cooling tower makeup | 27,200 | 21,900 | 13,800 |
| 29 | Cooling tower evaporation and drift[d] | 24,200 | 19,500 | 12,800 |
| 30 | Cooling tower blowdown | 3,000 | 2,400 | 1,500 |
| 31 | Wastewater holding pond evaporation | 65 | 65 | 65 |
| 32 | Wastewater holding pond exfiltration | 76 | 76 | 76 |
| 33 | Rainfall to roof and yard drains | 115 | 115 | 115 |
| 34 | Exfiltration of rainfall | 10 | 10 | 10 |
| 35 | Rainfall runoff | 105 | 105 | 105 |
| 36 | Final station effluent | [illegible],400 | 2,800 | 1,900 |
| 37 | Rainfall on presettling pond | 87 | 87 | 87 |
| 38 | Rainfall on wastewater holding pond | 240 | 240 | 55 |
| 39 | Ultimate heat sink makeup | 55 | 55 | 55 |
| 40 | Station service water returned to presettling pond | 0 | 0 | 0 |

From ER, Supp. 0, Table 3.3-1.

[a]Apparent discrepancies in the balance of flows reported are the result of rounding off calculated values.

[b]Refers to stream number shown in Fig. 3.2.

[c]All calculations are based on typical river water quality presented in ER, Table 2.4-8, corresponding to 2000 cfs median river flow. All values given are gallons per minute (gpm).

[d]Cooling tower evaporation rates are estimated based on average annual meteorological conditions (53°F wet-bulb temperature and t[illegible] 7 percent relative humidity).

[e]Includes evaporation from UHS s[illegible]e basin. The flow rates indicated are based on minimum flows over the UHS cooling tower

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The cooling water will be circulated through the condensers and cooling tower system at the rate of 1.244 × $10^6$ gpm (2770 cfs) for both units. As the water passes through the condenser, its temperature will rise approximately 26°F. The flow in the condenser-cooling tower system will be maintained by three pumps per unit.

### 3.4.2 Cooling Towers

Three round, mechanical-draft, cross-flow cooling towers, each about 60 feet high and 290 feet in diameter, will be provided for each unit. In this type of tower, the warmed water is pumped from the condenser into the top of the tower. The water is allowed to flow by gravity through a fill material, which slows the falling water and breaks it into small droplets, thus greatly increasing the time and area of contact of the water with the air. Most of the cooling results from the evaporation of a small portion of the circulating water; sensible heat transfer by conduction to air also contributes to the cooling process.

Air is circulated by 13 fans at the top of each tower. Drift eliminators inside the tower trap water droplets so that only about 0.005% of the circulating water is lost from the tower as "drift" (spray).

Table 3.2 lists the design parameters for the BFS towers; Figure 3.3 shows the cooling tower performance curve, which is used to determine the cold-water temperature as a function of wet-bulb temperature.

Table 3.2. Main Condenser Cooling System Design Parameters

| Parameter | Value |
|---|---|
| Circulating water flow (per generating unit) | 620,000 gpm |
| Round, mechanical-draft, cross-flow, wet cooling towers | |
| Number of towers per unit | 3 |
| Number of fans per tower | 13 |
| Tower diameter | 290 feet |
| Tower height | 60 feet |
| Cooling tower design | |
| Design wet bulb | 78°F |
| Design approach | 14°F |
| Inlet temperature | 117.4°F |
| Outlet temperature | 92.0°F |
| Design range | 26.1°F |
| Exit air velocity | 11.43 ft/sec |
| Exit air temperature | 107.1°F |
| Air flow rate per fan | 1,342,000 cfm |
| Maximum drift rate per unit | 31 gpm |

### 3.4.3 Discharge System

To insure efficient operation of the cooling sytem, it will be necessary to limit the buildup of dissolved solids that result from evaporation in the cooling towers and from chemicals added to prevent scaling. To accomplish this, a portion of the circulating water (blowdown) will be continuously removed from the cooling system. Blowdown will be routed to a wastewater holding pond (37 acres, average depth 5.6 feet) for further cooling (minimum holdup time about one day) and then will be discharged to the Verdigris River by means of a surface discharge channel. The depth and area shown on the applicant's drawings and figures clearly indicate that the pond has a minimum of 24 hours storage capacity. Figure 2.2 shows the relative location of these facilities and Figure 3.4 shows the details of the discharge flume.

The rate of blowdown discharge to the holding pond will vary from 2000 gpm to 2600 gpm for expected 80% station load operation. The expected annual maximum is 3000 gpm, and the realistic worst case is 4000 gpm. Discharge to the river will vary between 2340 gpm and 3080 gpm for the expected 80% load factor, and 3150 gpm for the realistic worst case (low river flow, extreme meteorological conditions).

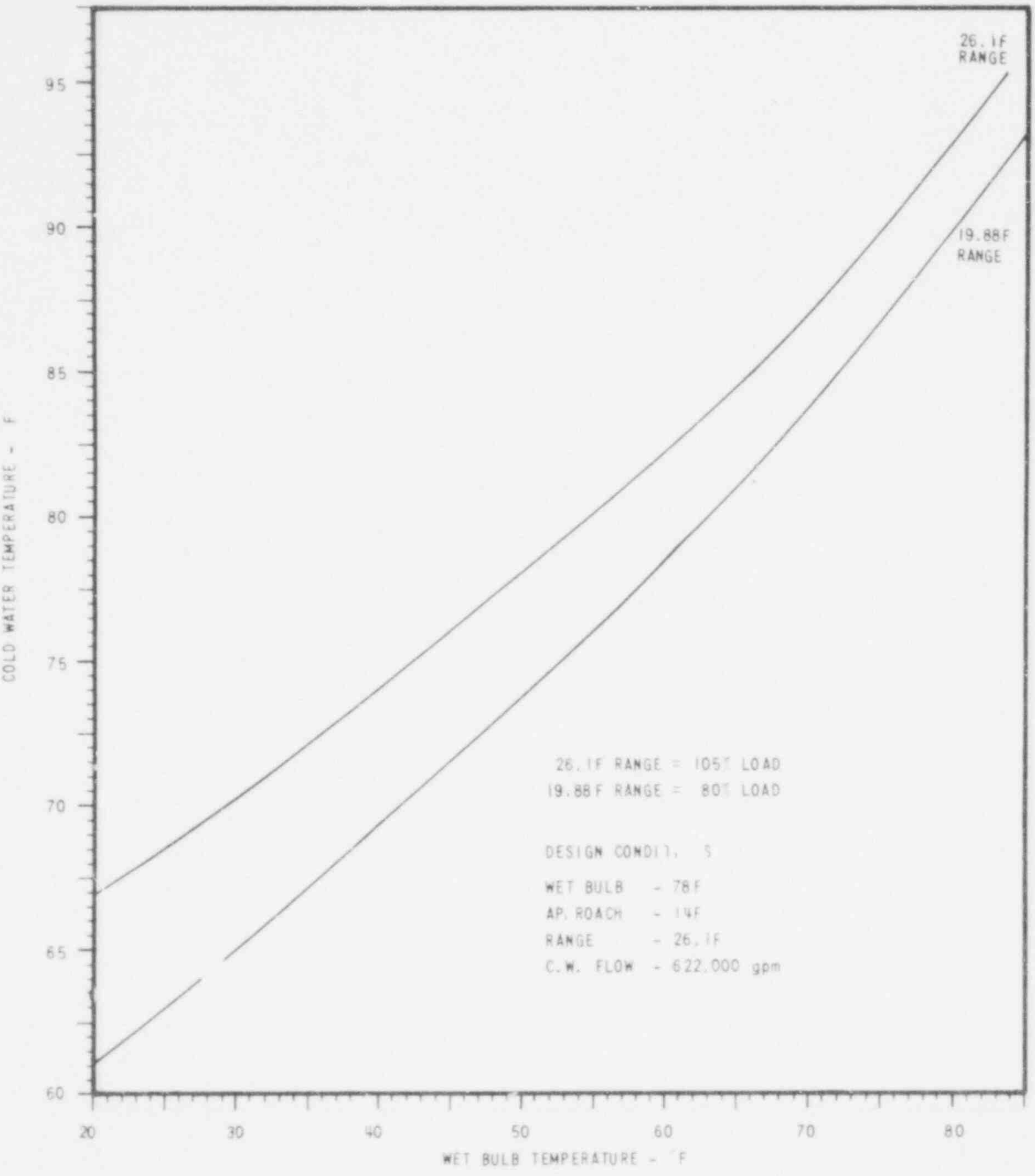


Fig. 3.3. Cooling Tower Performance Curves. From ER, Supp. 0, Fig. 0-3.7-1.

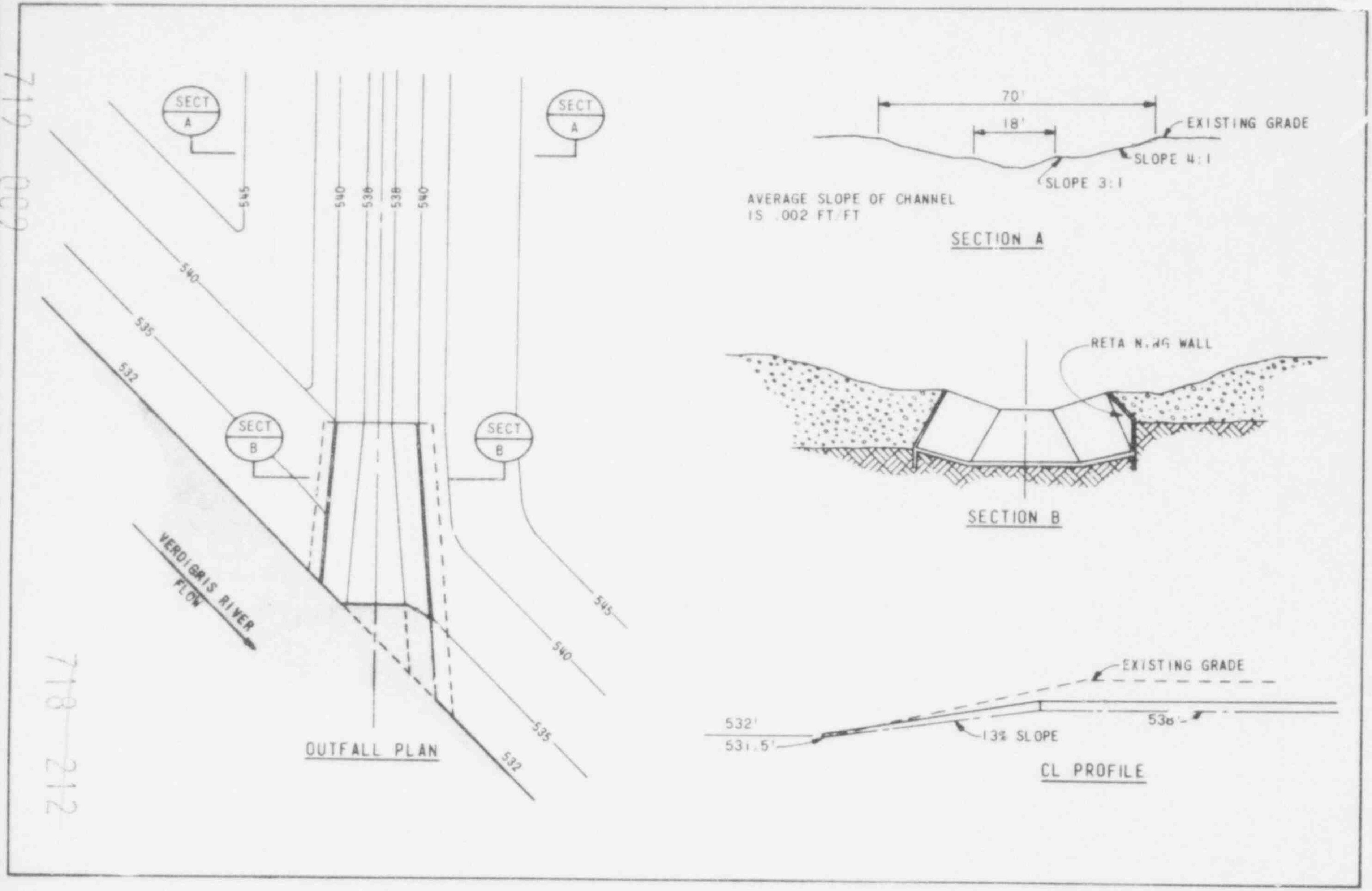


Fig. 3.4. Plant Wastewater River Outfall Structure. From ER, Fig. 3.4-6.



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3.4.4 Intake System

Makeup water for the cooling system will be obtained from the Verdigris River, via an intake structure approximately 11,000 feet upstream from the proposed discharge structure. Their relative locations to other site structures are shown in Figure 2.2. Details of the intake system are shown in Figure 3.5.

Makeup water will be withdrawn from the river through two 6-foot diameter, 35 foot long perforated pipes. The top of these pipes will be about 2.5 feet below low water level and the bottom of the pipes will be a minimum of 3 fee above the bottom. The holes will be 1/2 inch in diameter on 3/4 inch centers. The average desi approach velocity is 0.1 fps.

Buried pipes will deliver the makeup water to a dry pit pump house located approximately 400 feet from the shore. Two 35,000 gpm pumps will be installed, each capable of supplying the total makeup requirements of the station. This water will be discharged into the presettling pond. The makeup water will go first to the ultimate heat sink cooling towers before being added to the main circulating water system.

3.5 RADIOACTIVE WASTE SYSTEMS

During the operation of the BFS, radioactive material will be produced by fission and by neutron activation of corrosion products in the reactor coolant system. From the radioactive material produced, small amounts of gaseous and liquid radioactive wastes will enter the waste streams. These streams will be processed and monitored within the station to minimize the quantity of radioactive nuclides ultimately released to the atmosphere and to the Verdigris River.

The waste handling and treatment systems to be installed at the station are discussed in the applicant's PSAR and ER. In these documents, the applicant has prepared an analysis of his radioactive waste treatment systems and has estimated the annual release of radioactive materials in liquid and gaseous effluents. The BFS will consist of two GESSAR-238 NI (STN 50-447) units which will share liquid and solid radwaste systems rather than have the independent systems evaluated in the standard design. The gaseous radwaste system will be based on a proposed GESSAR-251 design (STN 50-531). Each unit will have a separate gaseous waste processing system.

In the following paragraphs, the radioactive waste treatment systems are described, and an evaluation is given, based on the staff's model of the applicant's radioactive waste treatment systems.

This model has been developed from a review of available data from operating nuclear power plants, adjusted to apply over a 30-year operating life. The reactor coolant activities and flow rates used in the evaluation are based on data from operating reactors. As a result, the parameters used in the model and the calculated releases vary somewhat from those used in the applicant's evaluation. The analytical techniques, parameters, and calculational model used in the evaluation are given in NUREG 0016, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling Water Reactors," April 1976. The principal parameters used in the staff's evaluation are given in Table 3.3.

The applicant has submitted a GE Topical Report, NEDO-21159, in support of his calculated releases of noble gases, radioiodines and particulates in gaseous effluents. The Report was found unacceptable by the staff under the Topical Report Review Program and, therefore, is not an acceptable reference at this time. In a letter dated December 7, 1976*, the applicant committed to add charcoal adsorbers and HEPA filters to the containment purge line, pending any NRC approved changes in source term or calculational methodology which makes this filter train unnecessary to meet the requirements of 10 CFR Part 50.34a.

In Supplement #0 to the ER, the Public Service Company of Oklahoma chose to comply with the September 5, 1975, amendment to Appendix I in lieu of performing a costbenefit analysis as required by Section II.D. This option permits an applicant to design its radwaste management systems to satisfy the design objectives proposed in the "Concluding Statement of Position of the Regulatory Staff" (RM 502), February 20, 1974.

The applicant proposes to use state-of-the-art technology for the liquid and gaseous radioactive waste treatment system. The staff evaluation in Section 5.4 demonstrates that the doses associated with the normal operation of the Black Fox Station, Unit Nos. 1 and 2, meet the design objectives of Sections II.A, B and C of Appendix I of 10 CFR Part 50, and that the expected quantity of radioactive materials released in liquid and gaseous effluents and the aggregate doses meet the design objectives set forth in RM-50-2.

*Letter from B.H.Morphis, Assistant Vice President-Nuclear, PSO to Wm. H. Regan, Jr., N.R.C.

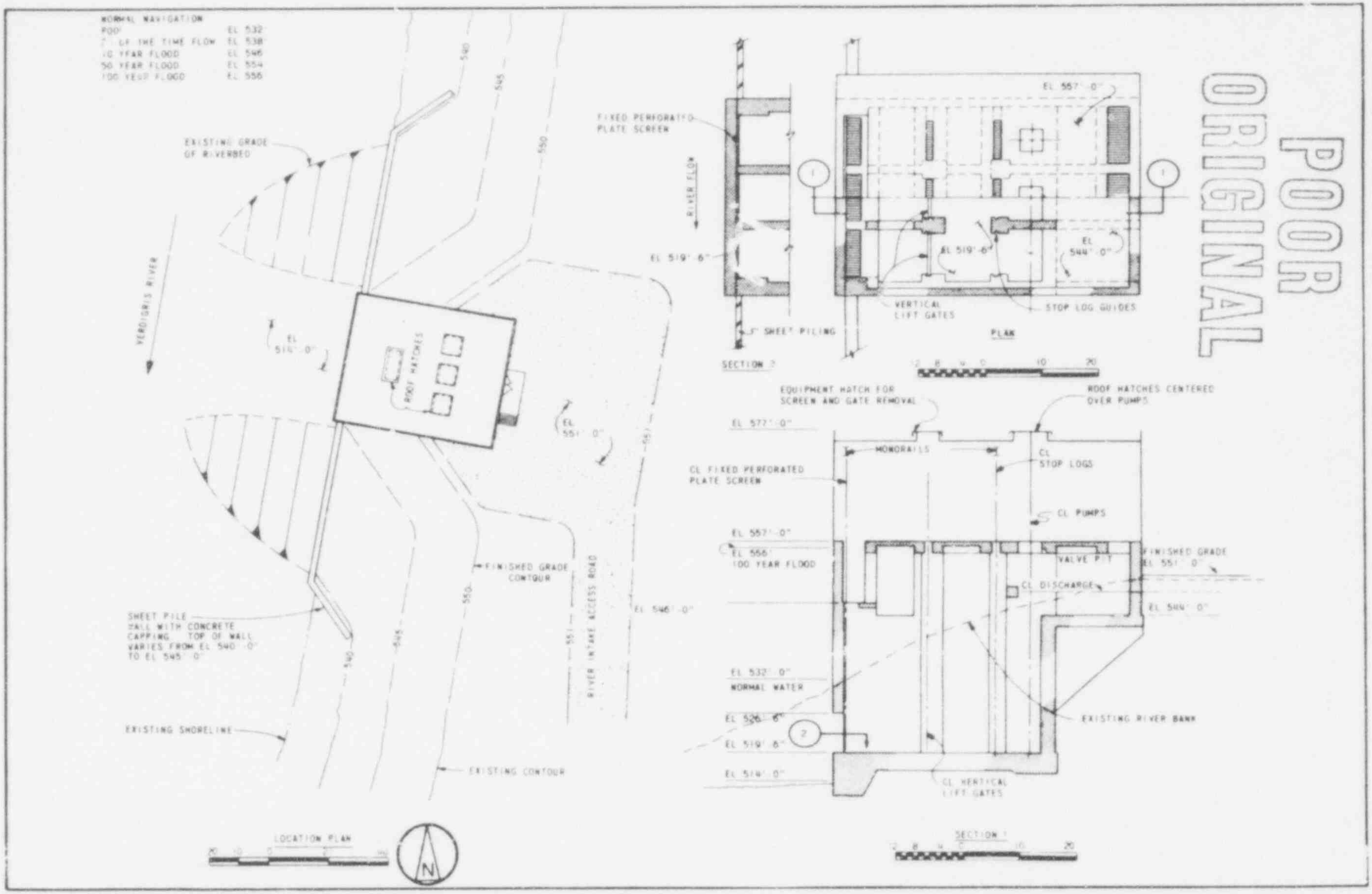


Fig. 3.5. Plant River Intake Structure. From ER, Fig. 3.4-3.

Table 3.3. Principal Parameters and Conditions Used in Calculating Releases of Radioactive Material in Liquid and Gaseous Effluents from Black Fox Station (per unit)

| Parameter | Value | | |
|---|---|---|---|
| Reactor power level (MWt) | 3580 | | |
| Plant capacity factor | 0.80 | | |
| Fraction of fuel releasing radioactivity to the primary coolant | | | |
| Noble gases | 60,000 μCi/sec for 3400 MWt after 30 min | | |
| Iodine-131 (independent of power level) | $5 \times 10^{-3}$ μCi/gm | | |
| Primary coolant system | | | |
| Weight of liquid in system (lb) | $4.9 \times 10^5$ | | |
| Cleanup demineralizer flow (lb/hr) | $1.5 \times 10^5$ | | |
| Steam flow rate (lb/hr) | $1.5 \times 10^7$ | | |
| Condenser air inleakage (scfm) | 20 | | |
| Condensate demineralizer flow (lb/hr) | $1.1 \times 10^7$ | | |
| Dilution flow (gal/min) | 3000 | | |
| Iodine partition factors (gas/liquid) | | | |
| Steam/liquid in the reactor vessel | 0.02 | | |
| Fraction of iodine getting through | | | |
| Condensate demineralizer | 0.1 | | |
| Cleanup demineralizer | 0.1 | | |
| Holdup times | | | |
| Charcoal delay krypton | 1.9 days | | |
| Charcoal delay xenon | 42 days | | |
| Decontamination factors | | I | Cs / Others |
| Waste collection system | | $10^3$ | $10^2$ / $10^3$ |
| Floor drain neutralizer system | | $10^4$ | $10^5$ / $10^5$ |
| | | All Nuclides Except Iodine | Iodine |
| Waste evaporator DF | | $10^4$ | $10^3$ |
| Detergent evaporator DF | | $10^2$ | $10^2$ |
| | Cation | Anion | Cs, Rb |
| Mixed-bed-deep-bed demineralizer (H + OH) DF[a] | $10^2$ (10) | $10^2$ (10) | 10 (10) |
| Mixed-bed (POWDEX) DF | 10 | 10 | 2 |
| Dynamic adsorption coefficients | | $Cm^3/gm$ | |
| Kr (operating temperature 0°F, dew point -20°F) | | 105 | |
| Xe (operating temperature 0°F, dew point -20°F) | | 2410 | |

[a]For two demineralizers in series, the DF for the second demineralizer is given in parentheses.

The staff's evaluation shows that the applicant's proposed design of Unit Nos. 1 and 2 satisfies the criteria specified in the option provided by the Commission's September 4, 1975 amendment to Appendix I and, therefore, meets the requirements of Section II.D of Appendix I of 10 CFR Part 50.

Based on the staff's evaluation, the proposed liquid and gaseous radwaste management systems for the Black Fox Station, Unit Nos. 1 and 2 meet the criteria given in Appendix I and are therefore, acceptable.

### 3.5.1 Liquid Wastes

The liquid radioactive waste treatment system will consist of equipment and instrumentation necessary to collect, process, monitor, recycle, or dispose of potentially radioactive liquid wastes. Units 1 and 2 will have a shared liquid radwaste system. Wastes will be processed on a batch basis to permit optimum control of releases. Treatment processes include filtration, evaporation, and demineralization. After processing, wastes will be collected and sampled to determine the radioisotopic content. Wastes which are discharged to the Verdigris River will be monitored for radioactivity. Discharges will be automatically terminated if radioactivity measurements exceed a predetermined level in the discharge line. A schematic diagram of the liquid radioactive waste system is shown in Figure 3.6. The liquid waste system is divided into three principal subsystems: waste collection system, floor drain neutralizer system, and detergent waste system for processing low conductivity, high conductivity, and detergent wastes, respectively.

#### 3.5.1.1 Waste Collection System

High purity wastes from equipment drains, ultrasonic resin cleaning, demineralizer resin transfers, and condensate demineralizer backwashes will be processed through the waste collection system. Based on the staff's parameters and information in the applicant's ER, the flow to the waste collection system was calculated to be approximately 29,500 gpd per reactor at 0.15 times primary coolant activity (PCA). Wastes will be collected in each of three 60,000-gallon low-conductivity tanks alternately. Assuming the collection tanks to be filled to 80% capacity, the collection time was calculated to be approximately 1.2 days and the process time to be 0.14 day per batch. Waste collector system wastes will be processed through one of two centrifugal filters and two mixed-bed demineralizers in series. Following processing, the treated wastes will be recycled to the condensate storage tank or collected in a 40,000-gallon excess-water tank for sampling and analysis. The staff estimates that 99% of the wastes will be recycled for reuse in the plant and that 1% of the wastes will be transferred from the excess water storage tank and batch processed through the detergent evaporator. The applicant considered that all of the high purity wastes will be recycled and included provisions for disposal to the detergent waste evaporator.

#### 3.5.1.2 Floor Drain Neutralizer System

The floor drain neutralizer system will collect low-purity, high-conductivity wastes from floor drain sumps, decontamination and chemical waste drains, and spent demineralizer regenerants. Wastes will be collected in one of two 30,000-gallon high-conductivity tanks. Based on the staff's parameters and information provided in the applicant's ER, the waste flow was calculated to be approximately 7400 gpd per reactor. Assuming one collection tank to be filled to 80% capacity, the collection time was calculated to be approximately 1.6 days. The pH of wastes will be adjusted with acid, caustic, or buffer chemical solutions prior to processing. Following adjustment, wastes will be processed through one of two 30-gpm waste evaporators and a mixed-bed demineralizer, and collected in a 40,000-gallon excess-water tank (separate from the waste collector system) for sampling and analysis. The staff estimates the time the wastes will be in the system for processing to be approximately 0.35 day based on the evaporator flow rate. It is estimated that 90% of the treated wastes will be recycled for reuse in the plant and 10% of the wastes will be discharged to the Verdigris River. The applicant estimated that 10% of the processed wastes will be discharged from the floor drain neutralizer system also.

#### 3.5.1.3 Detergent Water System

Detergent wastes from the plant laundry and laboratory washwater, approximately 1050 gpd per reactor at $10^{-4}$ μCi/gm, will be collected in the two 1500-gallon detergent waste systems. The wastes will be filtered and processed through the detergent waste evaporator. The staff estimates that a decontamination factor of 100 will be provided by the detergent waste evaporator. The evaporator distillate will be released to the atmosphere through the radwaste building vent as a vapor. These releases are considered in Section 3.5.2. The evaporator bottoms will be transferred to the solid waste treatment system and are considered in Section 3.5.3.

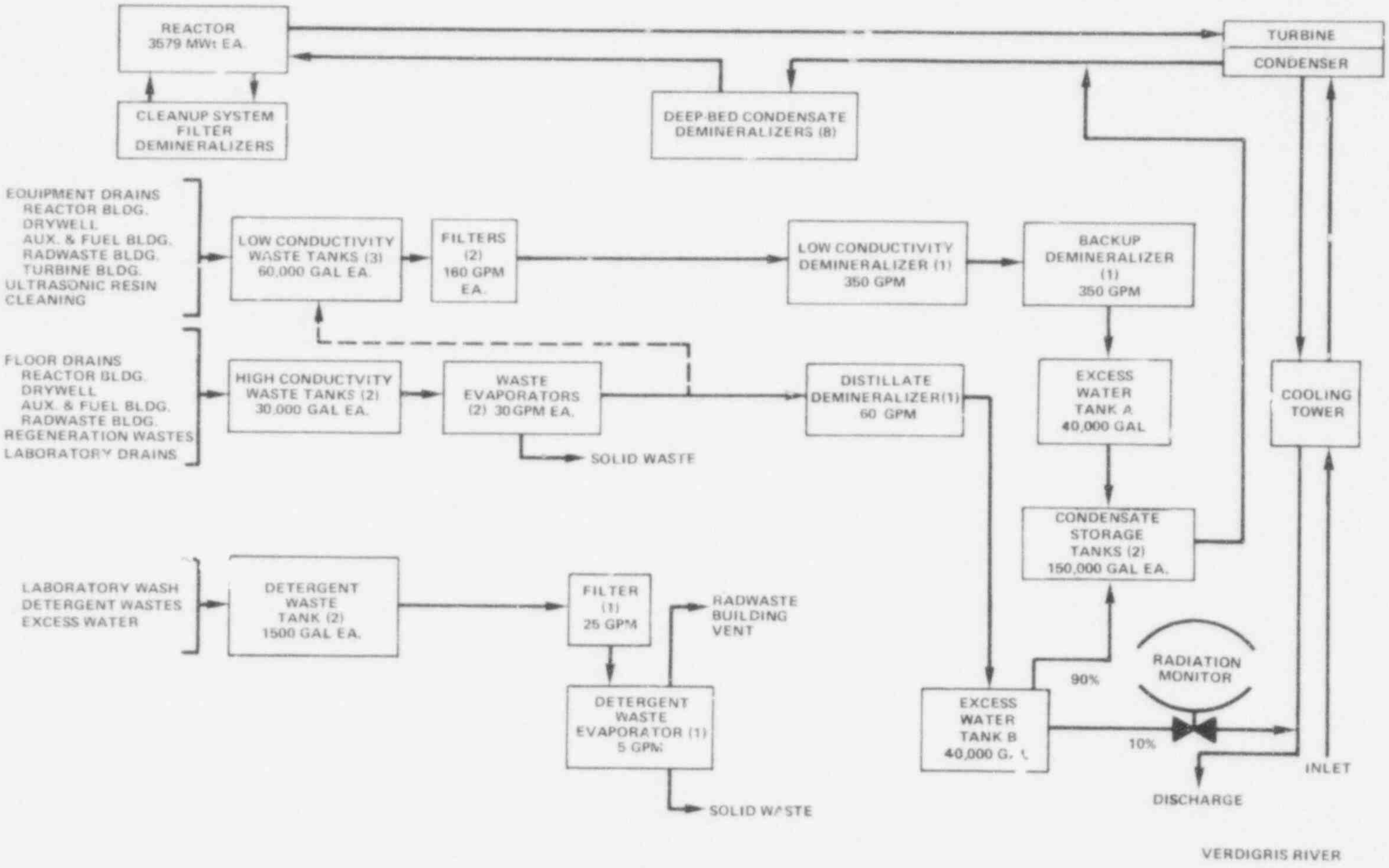


Fig. 3.6. Liquid Waste System, Black Fox Station, Units 1 and 2.



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### 3.5.1.4 Liquid Waste Summary

Based on the staff's evaluation of the liquid radioactive waste treatment systems, the release of radioactive material in liquid effluents is calculated to be approximately 0.16 Ci/yr/reactor, excluding tritium and dissolved gases. The staff estimates the annual tritium releases to be approximately 10 Ci/reactor. An isotopic listing of the calculated liquid radioactive source term is given in Table 3.4. The applicant estimates that the annual releases will be approximately 0.01 Ci/yr/reactor excluding tritium, but did not provide an estimate for the quantity of tritium expected to be discharged. The principal difference between the staff's release estimate and that of the applicant is that the staff assumed untreated releases during anticipated operational occurrences.

Table 3.4. Calculated Releases of Radioactive Materials in Liquid Effluents from Black Fox Station Units 1 & 2

| Nuclides[a] | Ci/yr/reactor | Nuclide[a] | Ci/yr/reactor |
|---|---|---|---|
| Corrosion & Activation Products | | Fission Products (cont.) | |
| Na-24 | 4(-5)[b] | | |
| P-32 | 4(-5) | Mo-99 | 7(-5) |
| Cr-51 | 1.6(-3) | Tc-99m | 9(-5) |
| Mn-54 | 3(-5) | Te-129m | 1(-5) |
| Fe-55 | 6.2(-4) | I-131 | 1.4(-1) |
| Fe-59 | 1(-5) | I-132 | 3(-5) |
| Co-58 | 1(-4) | I-133 | 1.7(-2) |
| Co-60 | 2.5(-4) | I-135 | 4.7(-4) |
| Cu-64 | 1.1(-4) | Cs-137 | 2(-5) |
| Zn-65 | 1.2(-4) | Ba-137 | 2(-5) |
| Np-239 | 2(-4) | Ba-140 | 7(-5) |
| | | La-140 | 8(-5) |
| Fission Products | | Ce-141 | 1(-5) |
| Sr-89 | 4(-5) | All Others[a] | 1.4(-4) |
| Y-91 | 3(-5) | Total (except H-3) | 1.6(-1) |
| | | H-3 | 10 |

[a]Nuclides whose release rates are less than $10^{-5}$ Ci/yr/reactor are not listed individually, but are included in the category "All Others."

[b]Exponential notation: $1.5(-3) = 1.5 \times 10^{-3}$.

### 3.5.2 Gaseous Wastes

The gaseous waste treatment and ventilation exhausts sysems will consist of equipment and instrumentation to reduce, control, and measure releases of radioactive materials in gaseous effluents from the plant. The principal source of radioactive gaseous wastes will be offgas from the main condenser air ejectors. Additional sources of gaseous wastes include gases purged from the main condenser by the mechanical vacuum pumps during plant startups, gases purged periodically from the reactor drywell, and ventilation air from buildings housing systems which contain radioactive materials. The turbine gland seals will be supplied with clean steam and are not expected to contribute to the gaseous source term. A refrigerated charcoal delay system will be used to remove iodine and delay noble gases contained in the offgas from the main condenser air ejectors. The reactor drywell will be processed through the standby gas treatment system prior to release. The gaseous waste treatment systems are shown schematically in Figure 3.7. Wastes which are discharged to the plant vent will be monitored for radioactivity. Discharges will be automatically terminated if radioactivity measurements exceed a predetermined level in the discharge line to the plant vent.

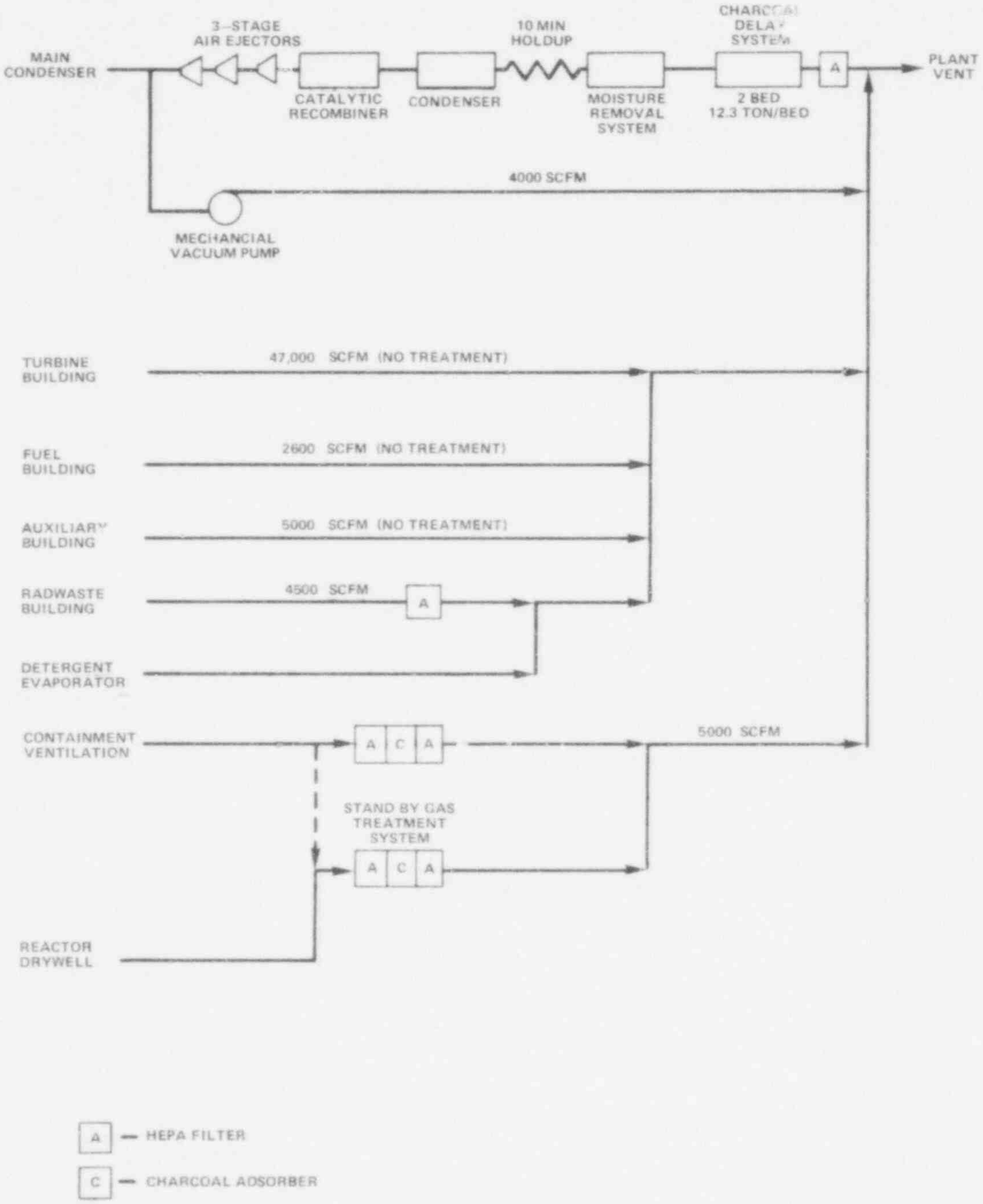


Fig. 3.7. Gaseous and Ventilation Waste Systems, Black Fox Station, Units 1 and 2.

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### 3.5.2.1 Main Condenser Air Ejector Offgas System

The offgas treatment systems will be separate for each unit. Each system will consist of redundant recombiners, moisture separators, desiccant dryers, prefilters, and two 12-ton charcoal delay beds. The system will be operated at 0°F. The staff has calculated the holdup time provided by the system to be approximately 1.[illegible] days for krypton and 42 days for xenon. In addition, based on the quantity of charcoal provided, iodine releases from the system are expected to be negligible. The staff estimates the airflow through the system to be approximately 20 scfm due to inleakage through the three main condenser shells. The parameters and calculated holdup times used in the applicant's evaluation were in agreement with those stated above. The staff calculated the annual releases from the offgas system to be approximately 800 Ci/reactor for noble gases and negligible for iodine-131. The applicant calculated the annual releases from this system to be approximately 1500 Ci/reactor for noble gases and negligible for iodine-131.

### 3.5.2.2 Mechanical Vacuum Pump

The mechanical vacuum pumps will be used to establish main condenser vacuum during plant startups. The staff expects the mechanical vacuum pump to be operated approximately 96 hours per year. Based on data from operating reactors, the annual releases from this source is calculated to be 2700 Ci/reactor for noble gases and 0.03 Ci/reactor for iodine-131. The applicant estimated the annual releases from the mechanical vacuum pump to be 500 Ci/reactor for noble gases and 0.32 Ci/reactor for iodine-131, based on NEDO-21159, Tables 2-3 and 2-1.

### 3.5.2.3 Reactor Drywell Purges

Radioactive gases will be released inside the reactor drywell when reactor coolant system components are opened or when leakage occurs from reactor coolant system component seals. The gaseous activity will be sealed within the drywell during normal operation but will be released during drywell purges. The drywell will be purged through the HEPA filters and charcoal adsorbers in the standby gas treatment system prior to release. The staff calculates the release of noble gases and iodine-131 from this source to be negligible.

### 3.5.2.4 Containment Building and Auxiliary Building Ventilation Air

Radioactive gases will be released to the reactor containment building and to the auxiliary building due to the leakage of reactor coolant from reactor coolant system components. Based on the applicant's amendment No. 7 to the E.R., the staff considered that ventilation air from the containment building will be released through charcoal adsorbers and HEPA filters. On the basis of the assumed leakage rate, the staff has calculated the annual releases from the containment and auxiliary buildings to total 0.19 Ci/reactor for iodine-131 and 320 Ci/reactor for noble gases. The applicant estimated the annual release from these sources to be 500 Ci/reactor for noble gases and 0.091 Ci/reactor for iodine-131, based on NEDO-21159, Tables 2-3 and 2-1.

### 3.5.2.5 Radwaste Building Ventilation Air

Radioactive gases may be released to the plant vent from the radwaste building due to leakage from process system components or equipment venting. One of the potential sources of gaseous activity that will be released through the plant vent is vapor released from the detergent waste evaporator vent. The staff's calculations show the gaseous activity released from the detergent waste evaporator to be negligible. The staff calculated the annual releases from the radwaste building to be approximately 55 Ci/reactor for noble gases and 0.05 Ci/reactor for iodine-131. The applicant has estimated the annual release of radioactive materials in ventilation air released from the radwaste building to be approximately 1500 Ci/reactor of noble gases and 0.034 Ci/reactor for iodine-131, based on NEDO-21159, Tables 2-3 and 2-1.

### 3.5.2.6 Turbine Building Ventilation Air

Radioactive gases will be released to the turbine building due to steam leakage from valves on process lines and equipment venting. The staff calculates the annual releases from the turbine building to be approximately 3400 Ci/reactor for noble gases and 0.19 Ci/reactor for iodine-131. The applicant estimated the turbine building ventilation releases to be 4000 Ci/yr/reactor for noble gases and 0.034 Ci/yr/reactor for iodine-131, based on NEDO-21159, Tables 2-3 and 2-1.

### 3.5.2.7 Gaseous Waste Summary

Based on the preceding evaluation, the staff calculates the annual release of radioactive materials in gaseous effluents to be approximately 7200 Ci/reactor for noble gases, 0.46 Ci/reactor for iodine-131, 0.065 Ci/reactor for particulates, 9.[illegible] Ci/reactor for carbon-14 and 79 Ci/reactor for tritium. The applicant calculated the annual releases to be approximately 8000 Ci/reactor for noble gases, 0.47 Ci/yr/reactor for iodine-131, and 0.1 Ci/yr/reactor for particulates. An isotopic listing of the staff's calculated gaseous radioactive source term is given in Table 3.5. Based on the staff's evaluation of the gaseous waste treatment systems, it calculates that the release of radioactive materials in gaseous effluents from the operation of two reactor units will result in an annual air dose due to gamma radiation of less than 10 mrad and an annual air dose due to beta radiation of less than 20 mrad at or beyond the site boundary. The total calculated annual quantity of iodine-131 released should not exceed 1 Ci/reactor, and the dose to any organ from all pathways (Section 5.4) for radioiodines and other radionuclides released to the atmosphere will not exceed 15 mrem/year from Black Fox Station, Unit Nos. 1 and 2.

### 3.5.3 Solid Waste

Solid waste containing radioactive materials will be generated during station operation. Solid wastes will be categorized as "wet" or "dry" based on the process needed to put the wastes in an acceptable form for packaging and shipment offsite for burial. Each dual-unit plant will share a solid radwaste system. Wet solid wastes will consist largely of spent demineralizer resins, filter sludges, and evaporator bottoms. The wet wastes will be mixed with cement in 50- and 170-cubic-foot shipping containers. The containers will be equipped with disposable mixing blades to facilitate mixing. Based on an evaluation of the time the wet solids will be held up in the plant due to collection, processing, and storage, the staff calculates an average decay time of 180 days prior to shipment. The staff calculates the annual solid waste shipments to total approximately 31,000 cubic feet per year containing 2100 Ci of activity, principally Cs-134, Cs-137, Co-58, Co-60, and Mn-54.

Dry solid wastes will consist largely of ventilation air filters, contaminated clothing and paper, and miscellaneous contaminated items, such as tools and laboratory glassware. Dry solid wastes will be packaged in 55-gallon drums using a hydraulic baler for compressible wastes. The staff estimates that approximately 550 drums per year per reactor of dry wastes containing a total of less than 5 Ci/yr will be shipped offsite.

The applicant has estimated the annual solid waste shipments will consist of 6,400 cubic feet per reactor of wastes containing 3920 Ci/reactor of activity. The applicant did not provide an estimate of the quantity or activity of dry solid wastes which will be shipped offsite annually.

#### 3.5.3.1 Solid Waste Summary

Based on the staff's evaluation of the solid waste system it is concluded that the system design will accommodate the wastes expected during normal operations, including anticipated operational occurrences, in accordance with existing Federal and local regulations. The wastes will be packaged and shipped to a licensed burial site in accordance with NRC and Department of Transportation regulations. Based on these findings, the staff concludes that the solid waste system is acceptable.

## 3.6 NONRADIOACTIVE WASTE SYSTEMS

### 3.6.1 Biocidal and other Chemical Effluents

A number of nonradioactive waste streams will be produced by plant operations, and all will be routed to the wastewater holding pond. The water quality of the final discharge will be determined primarily by the properties of the condenser cooling system blowdown because of its dominating volume. The properties of this discharge, in turn, with the exception of sulfate, alkalinity, and scale inhibitors, are determined by multiplying incoming river concentrations by the factor of nine (the design concentration factor) and are shown in Table 3.6. for the more abundant substances. This factor is determined by evaporation in the cooling towers and by the relative amounts of makeup and blowdown.

#### 3.6.1.1 Scaling Treatment

To operate at high solids concentration, the applicant proposes to add sulfuric acid and scale inhibitors to the circulating water system. Approximately 19,100 pounds of acid are to be added per day for both units. Each sulfate ion will displace two bicarbonate ions, which will be lost as $CO_2$ in the cooling towers.

The applicant expects to add, as well as the acid, a phosphonate or polyol phosphate ester scale inhibitor. Although the exact type and amount of inhibitor are not yet specified, the staff estimates the equivalent of about 5 ppm of phosphate in the discharge will be added. As phosphonate, or ester, the phosphorus will not be immediately available as orthophosphate; however,

Table 3.5. Calculated Releases of Radioactive Materials in Gaseous Effluents from Black Fox Station Units 1 & 2 (Ci/yr/reactor)

| Nuclides | Reactor Building | Turbine Building | Auxiliary Building | Radwaste Building | Air Ejector Waste Gas | Mech. Vac Pump | Total |
|---|---|---|---|---|---|---|---|
| Kr-83m | a | a | a | a | a | a | a |
| Kr-85m | 3 | 68 | 3 | a | 69 | a | 140 |
| Kr-85 | a | a | a | a | 290 | a | 290 |
| Kr-87 | 3 | 130 | 3 | a | a | a | 140 |
| Kr-88 | 3 | 230 | 3 | a | 4 | a | 240 |
| Kr-89 | a | a | a | a | a | a | a |
| Xe-131m | a | a | a | a | 18 | a | 18 |
| Xe-133m | a | a | a | a | a | a | a |
| Xe-133 | 66 | 250 | 66 | 10 | 410 | 2300 | 3100 |
| Xe-135m | 46 | 650 | 46 | a | a | a | 740 |
| Xe-135 | 34 | 630 | 34 | 45 | a | 350 | 1100 |
| Xe-137 | a | a | a | a | a | a | a |
| Xe-138 | 7 | 1400 | 7 | a | a | a | 1400 |
| I-131 | 1.7(-2)[b] | 1.9(-1) | 1.7(-1) | 5(-2) | a | 3(-2) | 4.6(-1) |
| I-133 | 6.8(-2) | 7.6(-1) | 6.8(-1) | 1.8(-1) | a | a | 1.7 |
| Cr-51 | 3(-6) | 1.3(-2) | 3(-4) | 9(-5) | c | c | 1.3(-2) |
| Mn-54 | 3(-5) | 6(-4) | 3(-3) | 3(-4) | c | c | 3.9(-3) |
| Fe-59 | 4(-6) | 5(-4) | 4(-4) | 1.5(-4) | c | c | 1.1(-3) |
| Co-58 | 6(-6) | 6(-4) | 6(-4) | 4.5(-5) | c | c | 1.3(-3) |
| Co-60 | 1(-4) | 2(-3) | 1(-2) | 9(-4) | c | c | 1.3(-2) |
| Zn-65 | 2(-5) | 2(-4) | 2(-3) | 1.5(-5) | c | c | 2.2(-3) |
| Sr-89 | 9(-7) | 6(-3) | 9(-5) | 4.5(-6) | c | c | 6.1(-3) |
| Sr-90 | 5(-8) | 2(-5) | 5(-6) | 3(-6) | c | c | 2.8(-5) |
| Zr-95 | 4(-6) | 1(-4) | 4(-4) | 5(-7) | c | c | 5(-4) |
| Sb-124 | 2(-6) | 3(-4) | 2(-4) | 5(-7) | c | c | 5(-4) |
| Cs-134 | 4(-5) | 3(-4) | 4(-3) | 4.5(-5) | c | 3(-6) | 4.4(-3) |
| Cs-136 | 3(-6) | 5(-5) | 3(-4) | 4.5(-6) | c | 2(-6) | 3.6(-4) |
| Cs-137 | 5.5(-5) | 6(-4) | 5.5(-3) | 9(-5) | c | 1(-5) | 6.3(-3) |
| Ba-140 | 4(-6) | 1.1(-2) | 4(-4) | 1(-6) | c | 1.1(-5) | 1.1(-2) |
| Ce-141 | 1(-6) | 6(-4) | 1(-4) | 2.6(-5) | c | c | 7.3(-4) |
| C-14 | 1.5 | a | a | a | 8 | a | 9.5 |
| H-3 | - | - | - | - | - | - | 79 |
| Ar-41 | 25 | c | c | c | c | c | 25 |

[a] Less than 1.0 Ci/yr noble gases, less than $10^{-4}$ Ci/yr for iodine.

[b] Exponential notation: 1.7(-1) = $1.7 \times 10^{-1}$

[c] Less than 1% of total for nuclide.

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Table 3.6. Wastewater Effluent Characteristics for BFS Normal Operation[a]

| Parameter | Verdigris River Water | Heat Dissipation System Blowdown[b] | Sludge Holding Pond Effluent[b] | Neutralization Basin Effluent[b] | Wastewater Holding Pond Effluent to River: 100%[c] Station Load | Wastewater Holding Pond Effluent to River: 80%[c] Station Load |
|---|---|---|---|---|---|---|
| Calcium | 40 | 360 | 20 | 337 | 309 | 299 |
| Magnesium | 7.3 | 66 | 6.5 | 110 | 57 | 55 |
| Total hardness (as $CaCO_3$) | 130[d] | 1172 | 77 | 1296 | 1007 | 974 |
| Sodium | 23 | 207 | 23 | 2438 | 192 | 186 |
| Alkalinity (as $CaCO_3$) | 97 | 250 | 35 | 0 | 220 | 213 |
| Sulfate | 34 | 900 | 41 | 5110 | 798 | 772 |
| Chloride | 37 | 333 | 37 | 624 | 289 | 279 |
| Nitrate | 0.51 | 4.5 | 0.5 | 8 | 3.9 | 3.8 |
| Silica | 6.5 | 59 | 6.0 | 101 | 51 | 49 |
| Phosphate (as $PO_4$) | 0.3 | 8.7 | 0.3 | 5.7 | 7.4 | 7.2 |
| TDS | 270[d] | 2250 | 160 | 8700 | 1922 | 1859 |
| Free Available Chlorine | - | 1[e] | - | - | - | - |
| Total Residual Chlorine | - | 1[e] | - | - | <0.01 | <0.01 |

From ER, Table 3.6-3; Supplement 3.

[a] Values of each parameter given as mg/l.

[b] Concentrations would be the same at station loads of 80% and 100%.

[c] 100% station load, the expected maximum, and 80% load, the average, are the normal station operating conditions.

[d] These parameters were computed from component parameter estimated values; the estimated values of total hardness and TDS based on actual measurements are 141 mg/l and 239 mg/l, respectively, as given in ER, Table 2.4-8.

[e] This is the maximum short-term chlorine concentration which will occur during part of the chlorination period.

hydrolysis of the carbon-phosphorus bond of phosponate or the ester bond is expected to occur in a period of several days, making phosphate "available" as orthophosphate.

Since scale inhibitors prevent only scale formation, not precipitation, it is probable that if they are used, the concentration of suspended solids in the water entering the wastewater pond will be increased and that the concentration of dissolved solids will be lower than that shown in Table 3.6. The existence of an increased amount of colloidal material is probable, although no information is presently available on its nature and behavior. Much of the suspended solids is expected to settle in the wastewater pond; however, due to a general lack of knowledge concerning the chemical-physical properties of scale inhibitors, the behavior of the colloidal material cannot be predicted at the present time.

3.6.1.2 Water Pretreatment

Water for use in the demineralizer system and water for potable, sanitary, laundry, and laboratory use will be obtained from the pretreatment system. The water will be clarified, softened with lime, filtered, and chlorinated. Water then will be used directly or transferred to the demineralizer units. The cationic and anionic exchanger resins will replace mineral cations and anions of the water with hydrogen and hydroxyl ions, respectively, forming water and leaving a highly purified low ionic water. The resins will be periodically regenerated with NaOH and $H_2SO_4$ solutions, and resulting waste streams will be routed to the wastewater pond. Chemicals added during pretreatment are given in Table 3.7.

Table 3.7. Water Pretreatment System Chemical Requirements, (total pounds per day)

| | 100% Station Load | 80% Station Load |
|---|---|---|
| Lime (90% CaO) | 360 | 330 |
| Alum (100% $Al_2(SO_4)_3 \cdot 18H_2O$) | 100 | 90 |
| Chlorine (100% $Cl_2$) | 25 | 23 |

From ER, Table 3.6-4.

The pretreatment unit will discharge from the solids contact unit and the filter backwash. The wastes ($\sim$ 9 gpm) will be routed to the sludge holding basin, and decanted water will be pumped to the wastewater holding pond.

3.6.1.3 Demineralization

Although discharges from the demineralizer system will have a high salt concentration, the volume of these discharges will be relatively small and thus will change the composition of the wastewater pond only slightly. The flows are shown in Table 3.1 and the composition is given in Table 3.6. Approximately 230 pounds per day of NaOH and 590 pounds of $H_2SO_4$ are to be used in regenerating the station's spent resins in batch operations. The waste material will be routed to the neutralization tank for pH adjustment and then discharged at the rate of 18 gpm to the wastewater pond.

3.6.1.4 Biocides

Chlorine is to be used to control biological growths in the service water and main condenser cooling systems. A solution of chlorine gas in water will be periodically injected into the station service water pump suction. The chlorinated water will then be circulated through the station service water system with excess returning to the presettling pond. The chlorine will be injected at a rate calculated to give about 1 ppm of total residual chlorine in the discharge to the wastepond and will amount to about 25 pounds of chlorine per day for the station.

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In the main condenser system, chlorine will be injected ahead of the condensers to achieve a total residual chlorine of about 1 ppm at the condenser outlet. Chlorination will occur for half an hour per day for each unit, and the chlorination periods for each unit will be staggered. About 620 pounds of chlorine per day are expected to be used for the station.

Blowdown from the cooling towers will be routed to the wastewater pond, where water will be held for a minimum retention time of about 24 hours. Chlorinated blowdown from one unit will be mixed with unchlorinated blowdown from the second unit. In the wastewater pond the chlorinated blowdown will be mixed with the unchlorinated blowdown released in the preceding 23 hours during which chlorination does not occur.

As a consequence of the extensive dilution and reaction of chlorine with the chlorine demand of the diluting water, combined with the effect of the 24-hour delay time, the staff believes that with proper chlorine control at the intake of the condensers, the total residual chlorine levels in the discharge will be undetectable.

A complete list of chemicals added, with some water quality data, is given in Table 3.8.

### 3.6.2 Sanitary and other Waste Systems

#### 3.6.2.1 Sanitary Waste System

Secondary sewage treatment will be provided by a two-basin, packaged, activated sludge unit of the extended aeration type. This type of unit is designed for relatively small installations, accepts periodic flows without detriment, and requires minimum supervision.

The capacity of the system with both basins operating is 50,000 gallons of effluent per day, and it will be adequate for the maximum work force of about 2200. Approximately 44,000 gallons of effluent per day are expected when the maximum work force is employed, with a five-day BOD of 100 pounds per day.

Following construction, one basin will be kept on standby, with the other unit providing treatment requirements for about 200 people. The plant operating crew will consist of about 140 people, and the resulting effluent is expected to be about 7000 gallons per day, with 15 pounds per day of BOD prior to treatment.

All sanitary effluents will be discharged to the wastewater pond, where BOD and suspended solids will be further reduced prior to discharge in the main wastewater stream. The expected quality of the effluent after treatment is shown in Table 3.9.

#### 3.6.2.2 Gaseous Releases

The auxiliary boilers for the station will be electrically powered and will not directly generate gaseous emissions.

Each emergency diesel generating unit will have one 2600-kW and two 5500-kW diesel generators. In normal plant operation the diesels will be operated only for testing, which will amount to a maximum of about two hours per month for each generator. Gaseous emissions from the diesel generators are shown in Table 3.10; it is expected that the applicant will use No. 2 diesel fuel oil with a heating value of 19,650 Btu per pound, a sulfur content of 0.5%, and ash content of 0.01%. The only emissions from the plant which could be subject to clean air laws are those from emergency diesel engines. Environmental Protection Agency does not have standards applicable to large stationary diesel engines nor are there any local regulations. It is unclear whether the Oklahoma regulations apply to internal combustion engines, however, the plant emissions of 2.66 lbs $NO_2$ per $10^6$ Btu would exceed the state limit of 0.3 lb/$10^6$ Btu.

## 3.7 POWER TRANSMISSION SYSTEM

### 3.7.1 Design Parameters

The BFS will interconnect with existing transmission systems of the applicant and of Associated Electric Cooperative. This interconnection will require the construction of about 278 circuit miles of new transmission lines (ER, Sec. 3.9) in northeastern Oklahoma, northwestern Arkansas, and southwestern Missouri. The rights-of-way (ROW) required for this system extend about 225 miles (Figs. 3.8 and 3.9) and cover almost 4000 acres (Table 3.11). Approximately three miles of ROW will be 100 feet wide to accommodate a 138-kV, three-phase, alternating-current line supported on single-circuit wood pole H-frames. An additional stretch of ROW (approximately 183 miles) will carry a single, 345-kV, three-phase, alternating-current line on wood pole H-frames. Seventy-eight miles of this ROW will be 130 feet wide, and 105 miles will be 150 feet wide. Of the

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Table 3.8. Expected Chemical Additive and Solids Concentration for Various Station Waste Streams at 100% and 80% Statior d

| Waste Stream Number[a] | Chemical Additive, lb/day | | | Total Dissolved Solids, mg/l | | Total Suspended Solids, mg/l | |
|---|---|---|---|---|---|---|---|
| | Chemical | 100% Station Load | 80% Station Load | 100% Station Load | 80% Station Load | Maximum | Average |
| 1 | - | - | - | 270 | 270 | b | 83 |
| 2 | c | c | c | 270 | 270 | b | b |
| 3 | - | - | - | 0 | 0 | 0 | 0 |
| 4 | - | - | - | 270 | 270 | Not applicable | |
| 5 | - | - | - | 160 | 160 | 50,000 | 5000 |
| 6 | - | - | - | 0 | 0 | 0 | 0 |
| 7 | - | - | - | 160 | 160 | Not applicable | |
| 8 | - | - | - | 160 | 160 | <5 | <5 |
| 9 | - | - | - | 160 | 160 | 100 | <100 |
| 10 | - | - | - | - | - | b | 100 |
| 11 | - | - | - | 160 | 160 | b | 240 |
| 12 | - | - | - | 160 | 160 | 100 | <30 |
| 13 | - | - | - | 160 | 160 | 100 | <100 |
| 14 | NaOH<br>$H_2SO_4$ (66° Bé) | 280<br>700 | 230<br>590 | 160 | 160 | <5 | <5 |
| 15 | NaOH | 250 | 220 | 8700 | 8700 | Negligible | |
| 16 | - | - | - | 8700 | 8700 | 100 | <30 |
| 17 | $Na_2Cr_7O \cdot 2H_2O$<br>NaOH | d<br>d | d<br>d | - | - | <1 | <1 |
| 18 | - | - | - | - | - | 0 | 0 |
| 19 | - | - | - | b | b | b | 5 |
| 20 | - | - | - | | | 1 | <1 |
| 21 | - | - | - | - | - | 1 | <1 |
| 22 | - | - | - | - | - | 0 | 0 |
| 23 | - | - | - | - | - | 0 | 0 |
| 24 | $Cl_2$ | 25 | 4C | 270 | 270 | b | b |
| 25 | - | - | - | 270 | 270 | Not applicable | |
| 26 | - | - | - | 270 | 270 | b | b |

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Table 3.8. Continued

| Waste Stream Number[a] | Chemical Additive, lb/day: Chemical | Chemical Additive, lb/day: 100% Station Load | Chemical Additive, lb/day: 80% Station Load | Total Dissolved Solids, mg/l: 100% Station Load | Total Dissolved Solids, mg/l: 80% Station Load | Total Suspended Solids, mg/l: Maximum | Total Suspended Solids, mg/l: Average |
|---|---|---|---|---|---|---|---|
| 27 | - | - | - | 160 | 160 | 100 | <30 |
| 28 | $Cl_2$<br>$H_2SO_4$ (66° Be) | 620<br>23,300 | 620<br>18,600 | 270 | 270 | b | b |
| 29 | - | - | - | 5.7 | 5.7 | <1 | <1 |
| 30 | - | - | - | 2250 | 2250 | b | b |
| 31 | - | - | - | 0 | 0 | 0 | 0 |
| 32 | - | - | - | 2040 | 1990 | Not applicable | |
| 33 | - | - | - | b | b | b | b |
| 34 | - | - | - | b | b | Not applicable | |
| 35 | - | - | - | b | b | b | b |
| 36 | - | - | - | 2040 | 1990 | b | b |

From ER, Supp. 0, Table 3.6-1.

[a]Waste stream designations are keyed to Figure 3.2, which shows their locations in the station water system, and to Table 3.1, which gives flow data.

[b]No reliable estimate obtainable from available data.

[c]See Table 3.6.

[d]A small quantity to be added to the closed cooling water system, which is a closed loop and is not expected to have any system blowdown.

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Table 3.9. Expected Sewage Treatment Plant Effluent Quality

| Constituent | Typical Value[a] |
|---|---|
| Ca | 20.0 |
| Mg | 6.5 |
| Na | 23.0 |
| $HCO_3$ | 21.0 |
| Cl | 41.0 |
| $SO_4$ | 37.0 |
| $NO_3$ | 0.5 |
| $SiO_2$ | 6.0 |
| $BOD_5$ | <30.0 |
| TSS | <30.0 |
| pH | 6.0-9.0 (units) |
| Fecal coliform bacteria[b] | 10,000/100 ml |

From ER, Table 3.7-1.

[a]All values in mg/l, except as noted.

[b]Estimate based on prior experience in sewage treatment facilities design and on assumption that secondary treatment will have essentially no effect upon this parameter.

remaining ROW, about 33 miles will be only 130 feet wide to accommodate double-circuit steel towers. The two circuits will be a 345-kV and a 138-kV circuit in an over/under configuration. The remaining seven miles will be multiple-line corridors. Five miles will require a 280-foot ROW for a double-circuit steel tower plus a single-circuit (345-kV) steel tower. Finally, there will be two miles of 430-foot ROW on which will be built two double-circuit steel towers and one single-circuit steel tower. The proposed power transmission system will be divided electrically into nine circuits (Table 3.12). However, for descriptive purposes, the transmission ROW can be divided into twelve sections (Fig. 3.10) and the longer sections further divided into subsections.

The applicant indicated that all new access roads will be temporary, with no permanent roads expected for operation and maintenance (ER, Sec. 3.9.10.3, p. 3.9-57). The staff infers that some new roads will have to be constructed, but that the applicant does not intend to maintain them.

The final routes for the lines have not been determined. The staff assumes that they will not diverge appreciably from the proposed routes described in the ER, Section 3.9, unless historical or archeological sites are discovered following staking (ER, Sec. 3.9.10.1, p. 3.9-55). If such is the case, the applicant will be required to submit, for staff review and approval, detailed information concerning the alternative route (see Sec. 4.1).

### 3.7.2 Right-of-Way Land Use

Present land-use patterns along the proposed ROW are summarized in Table 3.13. The table gives the percentage, by area, of each ROW section or subsection (as defined above) in each land-use category, and the number of highway, railroad, stream, and river crossings that will be required. Because of the strong seasonality of precipitation in the region, the staff considers the intermittent streams to be important features of the landscape and has included intermittent-stream crossings in its analysis. There are two trends apparent in the land-use patterns along the ROW: (1) there is a general increase in pastureland and a decrease in cultivated land from the west to the east; and (2) the ROW sections (II, V, and VIII) that approach Tulsa show a decrease in woodland or in cultivated land and a corresponding increase in "other" uses. Both trends occur uniformly over a ten-mile-wide transect paralleling the proposed transmission rights-of-way from Tulsa to Morgan Substation. The staff believes that the ROW are typical of these trends and that any alternative routes would show approximately the same land-use patterns.

Table 3.10. Diesel Generator Gaseous Emission Rates

| | Heat Input $10^6$ Btu/hour | Estimated Emission Rates | | | | | |
|---|---|---|---|---|---|---|---|
| | | Sulfur Oxides (as $SO_2$) | | Particulates[a] | | Nitrogen Oxides (as $NO_2$) | |
| | | lb/$10^6$ Btu | lb/hour | lb/$10^6$ Btu | lb/hour | lb/$10^6$ Btu | lb/hour |
| Rated capacity operation | | | | | | | |
| Division 1 diesel (5500 kW) | 53 | 0.485 | 26 | 0.359 | 19 | 2.66 | 140 |
| Division 2 diesel (5500 kW) | 53 | 0.485 | 26 | 0.359 | 19 | 2.66 | 140 |
| Division 3 diesel (2600 kW) | 26 | 0.485 | 13 | 0.359 | 9 | 2.66 | 67 |
| | | Expected Annual Emissions, lb | | | | | |
| | | Sulfur Oxides (as $SO_2$) | | Particulates | | Nitrogen Oxides (as $NO_2$) | |
| All plant diesels[b] | | 3,120 | | 2,260 | | 16,660 | |

[a]Includes unburned hydrocarbons and ash.

[b]For the two-unit station there will be a total of two Division 1 diesel generators, two Division 2 diesel generators, and two Division 3 diesel generators. These were assumed to operate on the normal schedule described in the ER, Section 3.7.4.2, testing each diesel generator two hours or less each month.

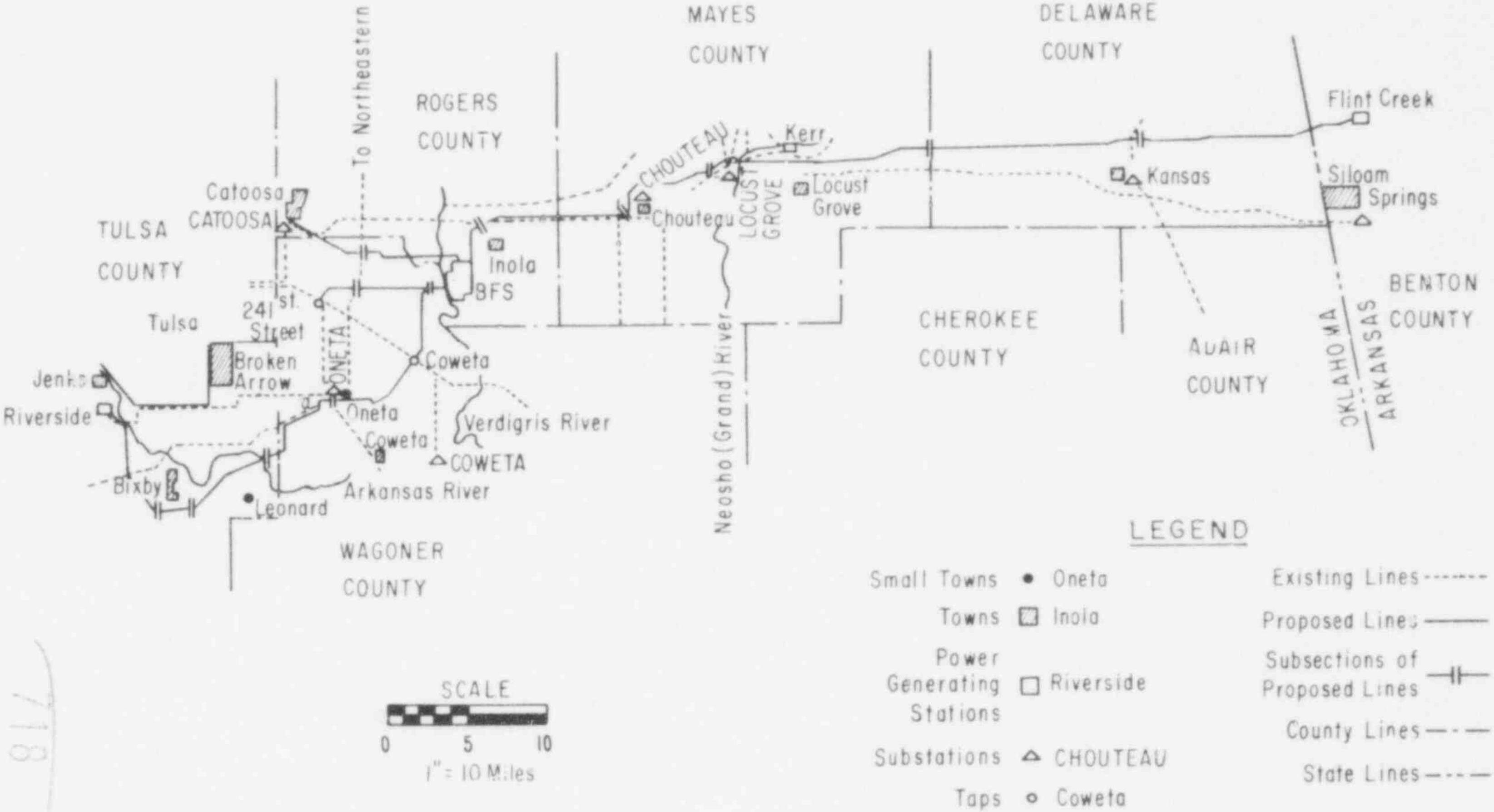


Fig. 3.8. Oklahoma Portion of BFS Transmission System.

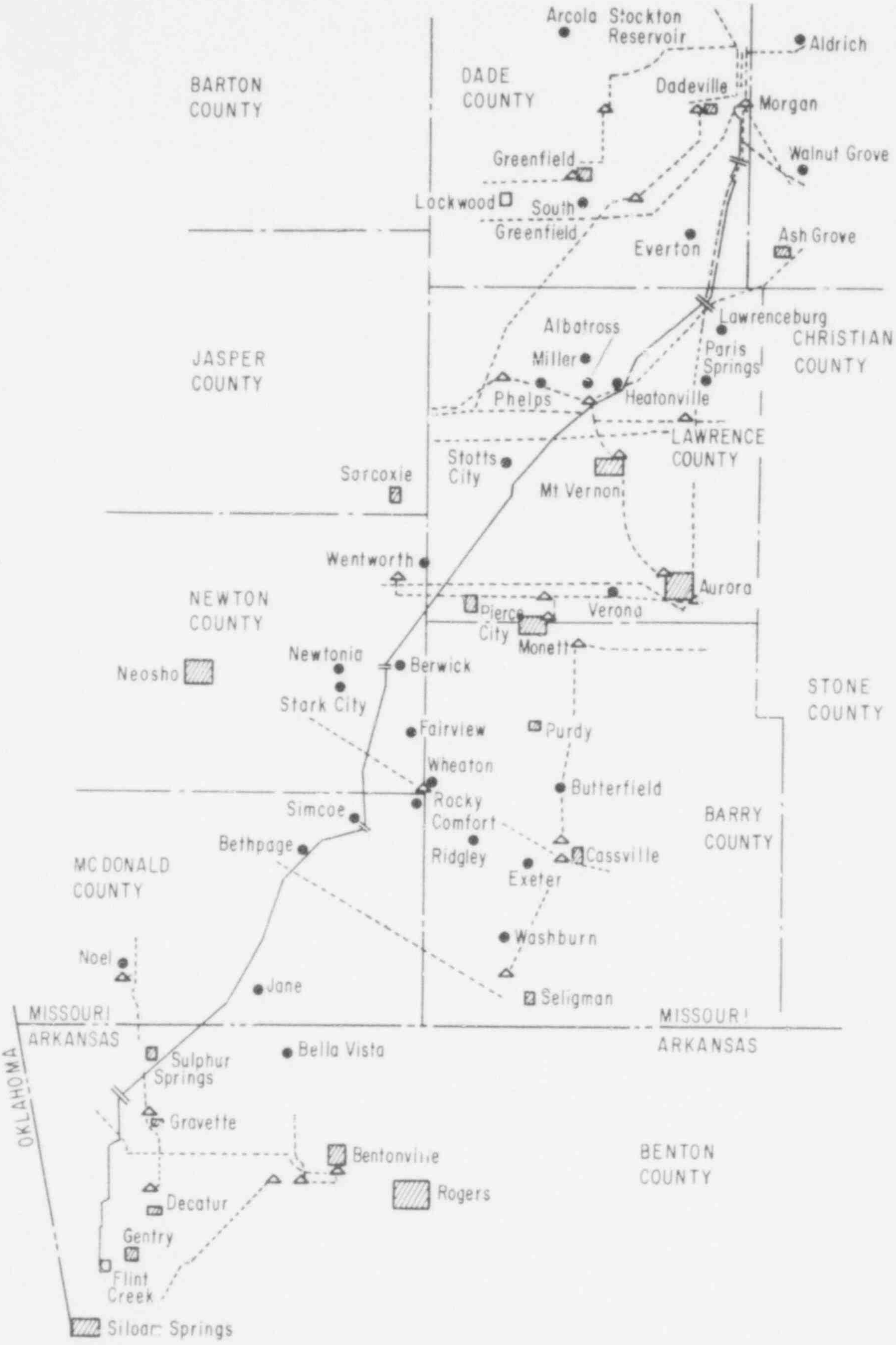


Fig. 3.9. Arkansas/Missouri Portion of BFS Transmission System.

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Table 3.11. Power Transmission Corridor Sections

| Section | Line | Voltage, kV | Tower Type[a] | Scheduled Completion |
|---|---|---|---|---|
| I | BFS-Northeastern | 345 | D/C ST | 1982 |
| | BFS-Catoosa | 138 | | 1976 |
| II | BFS-Catoosa | 345 | D/C ST | 1982 |
| | BFS-Catoosa | 138 | | 1978 |
| III | (Verdigris R. Crossing) | | | |
| | BFS-Catoosa | 345 | S/C ST | 1982 |
| | BFS-Oneta | 345 | D/C ST | 1982 |
| | BFS-241st St. tap | 138 | | 1981 |
| | BFS-Riverside | 345 | D/C ST | 1985 |
| | BFS-Coweta tap | 138 | | 1981 |
| IV | BFS-Catoosa | 345 | S/C ST | 1982 |
| | BFS-Oneta | 345 | D/C ST | 1982 |
| | BFS-241st St. tap | 138 | | 1981 |
| V | BFS-241st St. tap | 138 | S/C $WH_1$ | 1981 |
| VI | BFS-Riverside | 345 | D/C ST | 1985 |
| | BFS-Coweta tap | 138 | | 1981 |
| VII | BFS-Riverside (BFS-Oneta) | 345 | S/C $WH_2$ | 1985 |
| VIII | BFS-Riverside (Oneta-Riverside) | 345 | S/C $WH_2$ | 1985 |
| IX | BFS-Morgan | 345 | D/C ST | 1983 |
| | BFS-Chouteau | 138 | | 1978 |
| X | BFS-Chouteau | 138 | S/C $WH_1$ | 1978 |
| XI | BFS-Morgan (BFS-Flint Creek) | 345 | S/C $WH_2$ | 1983 |
| XII | BFS-Morgan (Flint Creek-Morgan) | 345 | S/C $WH_3$ | 1983 |

[a]Tower types:
D/C ST = Double-circuit steel towers
S/C ST = Single-circuit steel towers
S/C $WH_1$ = Single-circuit wood pole H-frame
S/C $WH_2$ = Single-circuit wood pole H-frame
S/C $WH_3$ = Single-circuit wood pole H-frame

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Table 3.12. BFS Transmission Line Circuits and Right-of-Way Sections

| Circuits | Right-of-Way Sections |
|---|---|
| BFS-Northeastern 345 kV | I |
| BFS-Catoosa 138 kV | I, II |
| BFS-Catoosa 345 kV | III, IV, II |
| BFS-241st St. tap 138 kV | III, IV, V |
| BFS-Oneta 345 kV | III, IV |
| BFS-Coweta tap 138 kV | III, VI |
| BFS-Riverside 345 kV | III, VI, VII, VIII |
| BFS-Chouteau 138 kV | IX, X |
| BFS-Morgan 345 kV | IX, XI, XII |

### 3.7.3 Right-of-Way Ecology

The ecology of the BFS transmission line ROW is dominated by the physiographic characteristics of the region. Knowledge of the general physiographic characteristics is necessary for understanding of the attendant ecology. The ROW cross two major physiographic provinces (Fig. 3.11): ROW Sections I through X, XIa, and XIb cross the Central Lowlands Province (Osage Plains section), and ROW Sections XIc, XId, XIe, and XII cross the Ozark Province (Springfield Plateau section).

The portion of the Osage crossed is a gently rolling plain approximately 600 to 700 feet above sea level. This plain is cut by the Arkansas (crossed by ROW Section VIIIa) and Verdigris Rivers (ROW Sections I and III). Both rivers have relatively low gradients and occupy broad floodplains (up to three miles wide) approximately 100 feet below the surrounding topography. There are three east-facing escarpments across the region: (1) between Inola and Pea Creeks (ROW Section IXb), (2) along the western edge of the Verdigris floodplain adjacent to the BFS site (ROW Sections I and VII), and (3) east of the towns of Catoosa and Broken Arrow (ROW Sections II and VIIIa). The latter escarpment has been strip mined.

The major soil association in the Osage Plains is Parsons-Dennis-Bates. The Dennis and Bates structures are well-drained, deep, loamy soils, while Parsons are slowly drained, deep loamy soils over very slowly permeable clay pan. Because of leaching, all are of low fertility. These are among the oldest soils of the State.[1]

The north-facing river bluffs in the Osage Plains support ecosystems sufficiently more mesic than normal for the physiographic section to warrant the designation of the ecosystems as "unique habitats."[2] One such unique habitat occurs on the BFS site (the mesic upland woods described in Sec. 2.7.1 of this Statement). Another site that is known to support a unique mesic habitat is the Lost City region[2] along the Arkansas River west of ROW Section VIIId, where smoke trees, blue ash (both are listed[3] as rare species R-1), and a relict population[2] of eastern chipmunks occur. The staff believes that the stand of unique habitat on the BFS site continues into the narrow ravine north of the northwestern corner of the site, where there is a crossing of an extensive woodland on ROW Section I. Most of the lowland woods along the Arkansas and Verdigris Rivers have been cleared and the soil drained to allow row crop agriculture on the rich alluvium. The only exceptions of interest are where ROW Section I traverses a half-mile-long segment of this habitat east of the Verdigris River crossing, and near the mouth of Adams Creek, where ROW Section IV crosses near the western edge of this stand. The remaining ecosystems are similar to those on the BFS site: the upland woods match the xeric upland woods on the BFS site; the pastures match the various grasslands on the BFS site; and the lowland woods along the permanent streams match the lowland woods along Inola Creek on the BFS site.

The portion of the Springfield Plateau crossed by the ROW is a deeply dissected plateau approximately 1200 to 1350 feet above sea level. The Grand (Neosho) River (crossed by ROW Section XIc) appears to follow the western edge of this plateau.[1] In this region there are many caves and springs. A considerable portion of the drainage is underground, and the surface streams tend to be clear, cool, fast-flowing mountain streams.[1,2]

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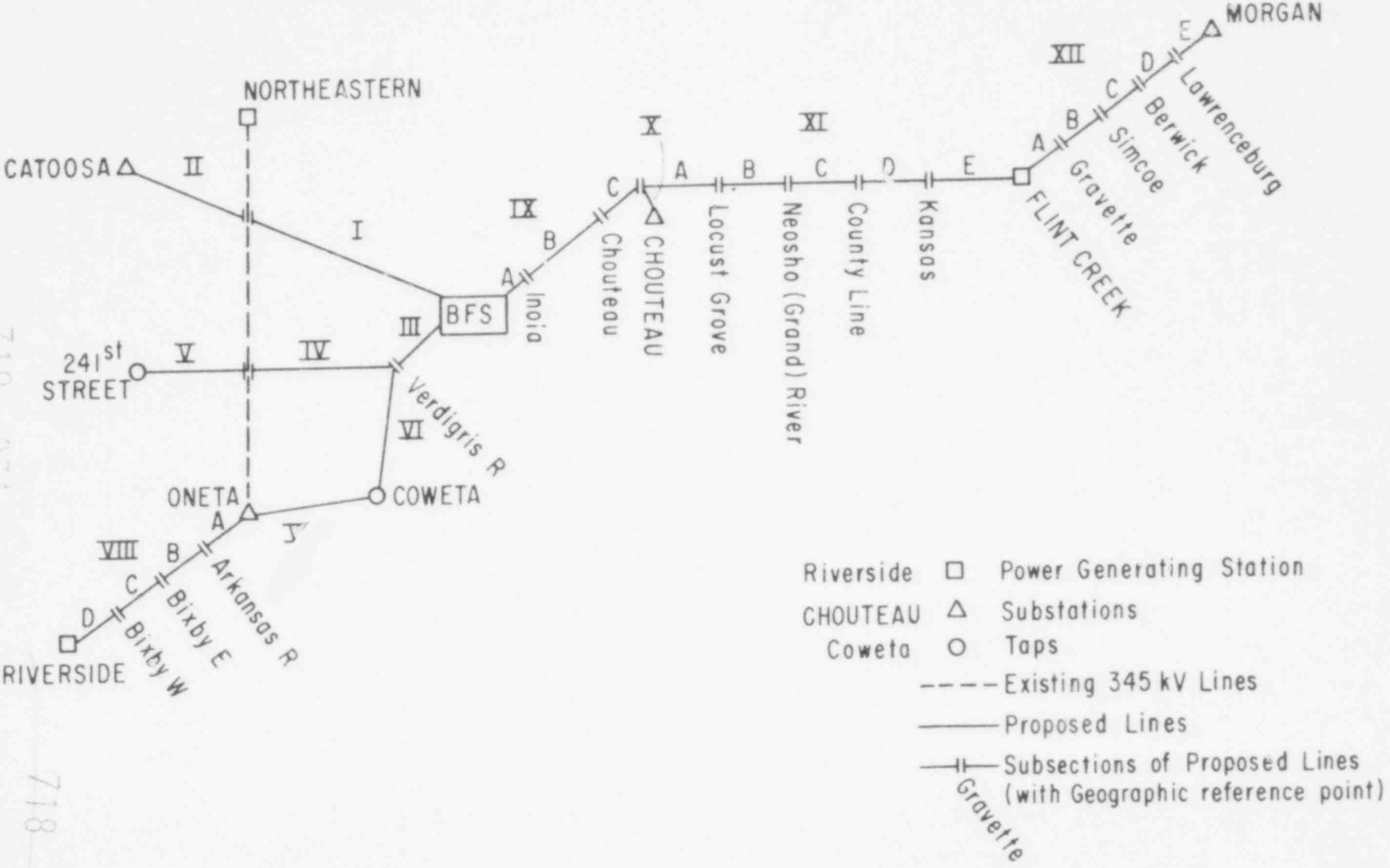


Fig. 3.10. Diagram of BFS Transmission System Showing ROW Sections and Subsections.

Table 3.13. Principal Characteristics of BFS Transmission Line Corrdiors

| Corridor | Land Use, percentage by area | | | | | Number of Crossings | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cultivated | Pasture | Woodland | Projected Residential | Other | River and Stream | Intermittent Stream | Highway | Railroad | Length, miles | Width, feet | Area, acres |
| I | 26.5 | 28.7 | 43.5 | - | 1.3[a] | 1 | 11 | - | - | 7.1 | 130 | 111.1 |
| II | 22.0 | 37.0 | 29.6 | - | 11.4[b,c] | 1 | 7 | 3 | - | 5.6 | 130 | 88.5 |
| III | 22.2 | 74.1 | - | - | 3.7[a] | 1 | - | - | - | 2.25 | 430 | 117.6 |
| IV | 36.4 | 37.4 | 26.1 | - | - | - | 8 | - | - | 5.25 | 280 | 178.4 |
| V | 3.0 | 76.8 | 20.2 | - | - | - | 6 | - | - | 2.5 | 100 | 30.2 |
| VI | 44.3 | 23.7 | 31.9 | - | - | 1 | 2 | - | - | 4.85 | 130 | 76.7 |
| VII | 54.0 | 42.4 | - | 3.6 | - | 1 | 6 | 1 | 1 | 6.9 | 130 | 106.4 |
| VIII | 51.5 | 24.4 | 6.3 | - | 17.8[d] | 8 | 17 | 2 | 3 | 21.7 | 130 | 342.0 |
| VIIIa | 71.3 | 8.2 | 0.5 | 15.5 | 4.5[d] | 1 | 2 | - | - | 6.8 | 130 | 106.1 |
| VIIIb | 97.4 | - | 2.6 | - | - | 1 | - | 1 | 1 | 5.3 | 130 | 84.3 |
| VIIIc | 50.8 | - | 16.5 | 32.7 | - | - | 1 | - | - | 2.3 | 130 | 36.4 |
| VIIId | - | 65.0 | 11.1 | - | 23.9[c] | 6 | 14 | 1 | 2 | 7.3 | 130 | 115.2 |
| IX | 13.4 | 76.4 | 10.2 | - | - | 1 | 6 | 2 | 1 | 14.5 | 130 | 229.2 |
| IXa | 14.5 | 84.1 | 1.4 | - | - | - | 1 | 1 | - | 3.9 | 130 | 62.1 |
| IXb | 13.5 | 71.3 | 15.2 | - | - | 1 | 4 | 1 | 1 | 9.4 | 130 | 147.7 |
| IXc | 9.3 | 90.7 | - | - | - | - | 1 | - | - | 1.2 | 130 | 19.4 |
| X | 18.6 | 81.4 | - | - | - | - | 1 | - | - | 0.5 | 100 | 5.9 |
| XI | 2.6 | 61.2 | 35.9 | - | 0.2[d] | 7 | 32 | 5 | 1 | 48.8 | 130 | 767.9 |
| XIa | - | 91.7 | 8.3 | - | - | 3 | 5 | 1 | 1 | 5.7 | 130 | 90.5 |
| XIb | - | 100 | - | - | - | 1 | - | - | - | 1.5 | 130 | 23.0 |
| XIc | 9.4 | 61.4 | 28.3 | - | 0.9[d] | 1 | 5 | 2 | - | 13.4 | 130 | 211.9 |
| XId | - | 47.5 | 52.5 | - | - | - | 8 | 1 | - | 14.3 | 130 | 223.8 |
| XIe | - | 58.5 | 41.5 | - | - | 2 | 14 | 1 | - | 13.9 | 130 | 218.7 |
| XII | - | 72.5 | 27.5 | - | - | 19 | 43 | 17 | 5 | 104.6 | 150 | 1901.5 |
| XIIa | - | 62.5 | 37.5 | - | - | 1 | 8 | 3 | - | 12.9 | 150 | 234.2 |
| XIIb | - | 43.2 | 56.8 | - | - | 6 | 19 | 5 | 1 | 27.7 | 150 | 503.4 |
| XIIc | - | 79.1 | 20.9 | - | - | 5 | 4 | 3 | 1 | 16.0 | 150 | 291.3 |
| XIId | - | 85.8 | 14.2 | - | - | 3 | 8 | 5 | 2 | 32.8 | 150 | 596.4 |
| XIIe | - | 98.9 | 1.1 | - | - | 4 | 4 | 1 | 1 | 15.2 | 150 | 276.2 |
| Total | 11.6 | 61.1 | 25.1 | - | 2.1[d] | 40 | 139 | 30 | 11 | 224.55 | | 3955.4 |

[a] River channel or reservoir.

[b] Highway (I-44) ROW and strip mine.

[c] Public Service Company of Oklahoma owned.

[d] Includes residential.



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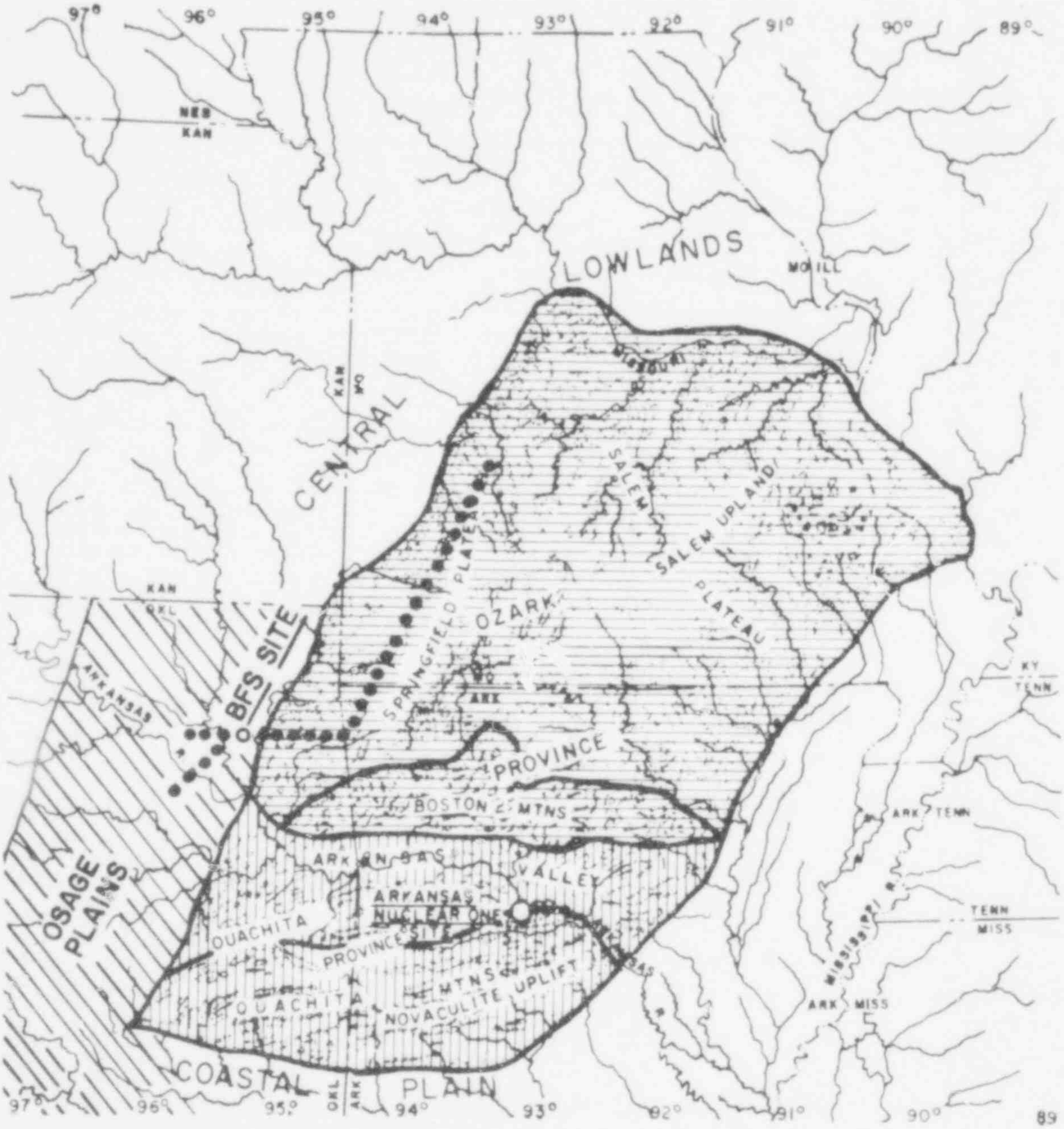



Fig. 3.11. Geographic Regions Around the BFS Power Transmission System Modified from "Final Environmental Statement, Arkansas Nuclear One, Unit 1," Fig. 2.7, U. S. AEC, Docket No. 50-313, February 1973.

The major soil association in the Oklahoma portion of the Springfield Plateau is Bodine (Clarksville) - Baxter. These are highly leached and weathered soils of low fertility and low water-holding capacity, with abundant coarse chert fragments.[1] Similar soils are expected to occur throughout those portions of the plateau of interest to this analysis.[4] However, a short distance south of the Grand (Neosho) River crossing, along the edge of the Springfield Plateau, the soils are of the Hector-Linker Association. These soils are acidic, shallow to very shallow with steep slopes and rock outcrops, of low fertility, and highly erodable.[1]

Because the streams of the physiographic section are characteristically spring-fed, and cool to cold, clear mountain streams, they are considered to be ecologically fragile.[2] Among these streams are the Illinois River and its tributaries including Flint Creek. The Illinois River and Flint Creek have been designated as state Scenic Rivers, and the Illinois River and its environs have been proposed for inclusion in the Federal Wild and Scenic Rivers System. Stream crossings are shown in Table 3.13. The caves of the region also support unique fauna.[1,2,4,5] The north-facing bluffs in Oklahoma, Arkansas, and extreme southern Missouri can be expected to support communities markedly more mesic than typical for the region.[2,4] The most striking known example of this occurs at Dripping Springs (three miles east of the Oklahoma Highway 33 crossing of Flint Creek and four miles south of ROW Section XId), where liverworts and ferns are abundant.[2] The north-facing bluffs of Spavinaw Creek are known[2] to support two rare (R-1) tree species--blue ash and ninebark.[3] Numerous other examples of north-facing bluffs in narrow ravines occur near or across ROW Sections XId, XIe, XIIa, and XIIb. The staff expects that many of these bluffs support comparable unique habitats. The Hector-Linker soils of the region support xeric scrub oak (black-jack oak) savannah communities (Ref. 1 and staff observations) comparable to the Cross-Timbers region west of Tulsa.

Other than the areas described above as being of particular ecological interest, transmission ROW Sections XIc, XId, XIe, and XIIa can be described as a transect from biotic communities typical of the Cherokee Prairie biotic district to communities typical of the Ozark biotic district. The western end of this transect resembles the BFS site, with mesic upland woods similar to those of the BFS site confined to sheltered slopes. To the east, the xeric upland woods become confined to exposed slopes, while the mesic upland woods occupy the less-exposed slopes. Sheltered slopes support a more mesic forest, including sugar maple, hop hornbeam, flowering dogwood, white oak, chinquapin oak, and linden (ER, Sec. 3.9.8.1). On the eastern end of the transect the typical upland forests are red oak-white oak-shagbark hickory forests, with forests comparable to the BFS site mesic forest occurring on exposed slopes, and with beech-maple cove forests in sheltered ravines.[4,6,7]

The remainder of ROW Section XII is a mosaic of forest communities similar to that described above for Section XIIa and prairie pastureland on the flat uplands of the Springfield Plateau. The grassland communities of the entire region appear to be similar to those on the BFS site.

### 3.7.4 Right-of-Way Archeology

The applicant states that one objective of transmission route selection was to cause the least interference to historical and archeological sites (ER, p. 3.9-56). Locations of such sites were determined by record searches in Federal and State registries (when available) (ER, p. 3.9-54). To locate new and unregistered sites, the applicant has made a commitment to have the staked routes reviewed by personnel certified by the State Historic Preservation Officer (ER, p. 3.9-55)

#### References

1. "Appraisal of the Water and Related Land Resources of Oklahoma, Region Nine," Oklahoma Water Resources Board, Publ. 36, 1971.

2. A. P. Blair, "Report on Areas of Ecological Significance in Eastern Oklahoma," Appendix B, In: Sargent and Lundy Report SL-2864, Nuclear Station Site Selection Study-Phase I, Chicago, Ill., October 1972.

3. "Rare and Endangered Vertebrates and Plants of Oklahoma," Rare and Endangered Species of Oklahoma Committee and U. S. Dept. of Agriculture, Soil Conservation Service, 1975.

4. "Arkansas Natural Area Plan," State of Arkansas, Dept. of Planning, December 1974.

5. "Rare and Endangered Species of Missouri," Missouri Dept. of Conservation and U. S. Dept. of Agriculture, Soil Conservation Service, 1974.

6. "Draft Environmental Statement, Arkansas Nuclear One Unit 2," U. S. Atomic Energy Commission, Directorate of Licensing, Docket No. 50-368, July 1972.

7. "Draft Environmental Statement, Arkansas Nuclear One Unit 1," U. S. Atomic Energy Commission, Directorate of Licensing, Docket No. 50-313, October 1972.

# 4. ENVIRONMENTAL IMPACTS OF CONSTRUCTION

## 4.1 IMPACTS ON LAND USE

The major impacts on land use during the construction period (see Fig. 4.1) will be associated with the construction of the central complex (including the power center, cooling towers, switchyard, ultimate heat sink, construction laydown areas, concrete batch plant, topsoil storage area, parking lot, etc., see ER, Fig. 2.1-4) where about 470 acres will be disturbed. An additional 125 acres will be disturbed during construction of the presettling pond, wastewater holding pond, and the river intake structure and barge slip. The acreages involved are listed in Table 4.1.

### 4.1.1 Onsite

#### 4.1.1.1 Central Complex

Approximately 466 acres, or 21% of the BFS site, will be disturbed by construction of the central complex. Only half of this acreage will be returned to its original condition. All but 15% of the total area to be disturbed is pasture. Since the average carrying capacity of the BFS site is 1 AU*/4 acres in wet years, or 1 AU/6 acres in dry years (ER, Supplement 0, Answer 2.6), the loss of potential livestock production will be 75-115 AUs per year during construction and 35-55 AUs per year for the rest of the life of the plant.

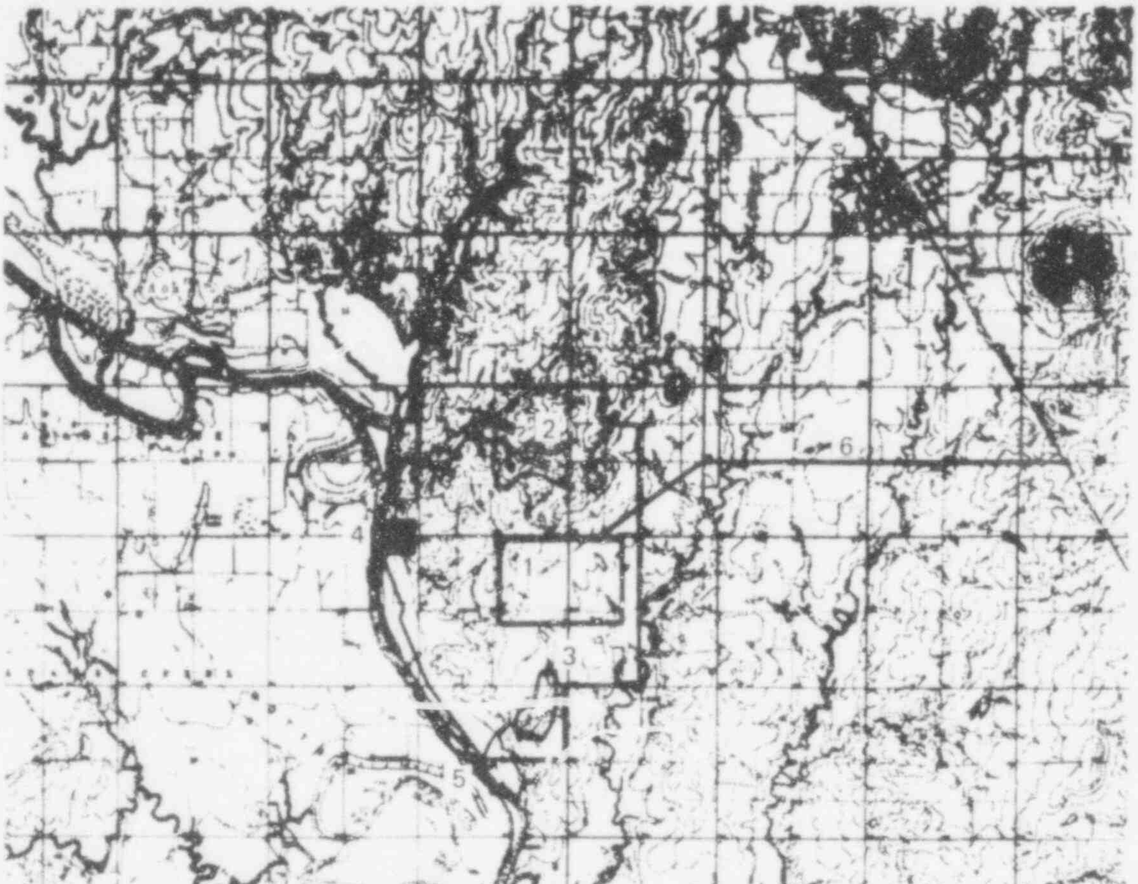
The soils of the central complex site are of the Bates-Collinsville complex, Chouteau silt loam, and Dennis-Bates complex (ER, Fig. 2.5-7). All of these are fine soils, with a high percentage (70-90%) passing a No. 200 sieve. They are of moderate to moderately slow permeability and of low to moderate shrink-swell potential (ER, Table 2.5-2). Such soils are characterized by a high runoff rate and high erodability during a moderately intense rainfall. The high runoff rate will intensify the erodability of the soil, especially as the silt load generated from sheetwash exerts an abrasive effect wherever runoff becomes concentrated.

Surface drainage patterns will be altered on the central complex site (Fig. 4.2). The staff estimates that the Diem's Pond watershed will be reduced about 28 percent by the diversion of the central complex drainage into the wastewater holding pond. The drainage basins of several small ponds in the Inola Creek watershed will be greatly reduced or eliminated. The ecological implications of these altered drainage patterns are discussed in Section 4.3.2.3. Correspondingly, the drainage basin in which the wastewater holding pond will be located will be increased by 75 percent.

Since most of the precipitation at the BFS site occurs as rain during spring thunderstorms (ER, Sec. 2.3.2.6), runoff and resultant soil erosion are likely to be a problem in the draw that will carry the runoff from the central complex site to the wastewater holding pond. The staff has estimated (using Beasley's formula[1]) that the one-year return period peak runoff rate from the central complex site will be greater than 500 cfs. Since the applicant has proposed grading this draw (ER, Sec. 4.1.3.1, p. 4.1-18), the staff concludes that the probability of gully erosion beginning in this draw is extremely high. Such erosion may increase siltation into the wastewater holding pond sufficiently to exceed the design volume of the wastewater holding pond during construction. Upslope increases in gully length may also breach the construction site, resulting in extreme siltation of the pond. Therefore, the staff requires annual inspections of the draw that will carry surface runoff from the central plant facilities site to the wastewater holding pond. If gully erosion is discovered during these inspections, appropriate mitigating action, such as rip-rapping, regrading, or revegetation, must be taken to reduce this erosion. Other avoidable adverse impacts of the construction of the central plant facilities include siltation of Diem's Pond and Inola Creek.

In order to assure the effectiveness of the proposed drainage plan for the central plant facilities site in containing any siltation, the staff requires several additional measures affecting site grading and handling of disturbed land. Drainage grading at the central complex site must be completed sufficiently to establish the proposed drainage patterns (Fig. 4.2) prior to any

*An "AU" is an "animal unit," approximately equivalent to one cow and a calf.




LEGEND

1. Central Station Complex
2. Presettling Pond
3. Wastewater Holding Pond
4. Barge Slip/Intake Structure
5. Wastewater Outfall Structure
6. Railroad Spur



Fig. 4.1. Construction Impact Areas. Modified from ER, Fig. 2.2-18.

Table 4.1. Approximate Acreage To Be Disturbed by Construction of BFS

| Habitat | Central Complex[a] | River Intake and Barge Slip[b] | Presettling Pond | Wastewater Holding Pond | Total |
|---|---|---|---|---|---|
| Xeric woods | - | 3 | 8 | 25 | 36 |
| Mesic woods | - | - | - | - | - |
| Upland pasture | 35 | 3 | 11 | - | 49 |
| Prairie hay | 68 | - | 11 | - | 79 |
| Lowland unimproved pasture | 200 | 1 | - | - | 221 |
| Lowland improved pasture | 123 | 33 | - | - | 136 |
| Other | 40 | 2 | 16 | 12 | 70 |
| TOTAL | 466 | 42 | 46 | 37 | 591 |
| Pe.manently Committed | 130 | 4 | 46 | 37 | 217 |

[a]Includes construction parking facilities, concrete batch plant, drainage grading at the central complex and drainage grading between the central complex and wastewater holding pond.

[b]Includes dredge spoil area (estimated by staff), and pipeline (estimated by applicant).

site excavation for the central complex structures. such grading must maintain this drainage pattern. The proposed cut and fill operations at the central complex site involve cutting the power center site to an elevation of 575 feet, cutting the northwest corner of the cooling tower site and filling the remainder of the cooling tower site to achieve a nominal elevation of 573 feet. The applicant states that the spoil from the cuts at the central complex site will be sufficient to supply the above described fill (ER Supplement 3, Section 4.1.1.3.5, p. 4.1-5). Fill material to raise the switchyard to an unspecified elevation (ER Supplement 3, Section 4.1.1.3.5) will have to come from excavations at the central complex site. Borrow areas should not be required for onsite fill The applicant has committed to topsoiling as an aid to reclaiming the disturbed lands at the central complex site (see Sec. 4.5.1).

The staff agrees with the applicant that dewatering wells will probably not be required. However, if it is determined during construction that such wells are necessary, the staff will require that the applicant design a monitoring program to detect adverse impacts on groundwater availability in the vicinity of the BFS site and submit the plan for staff approval prior to the construction of the wells. Inflows of infiltrated groundwater and of surface water will be collected in sumps and pumped into the wastewater holding pond.

#### 4.1.1.2 Presettling Pond

An existing 3.4-acre pond will be enlarged to about 45 acres for the presettling pond. Other than the existing open water, this acreage is presently either in pasture or in hay production. The permanent loss of potential livestock production will be about 4.5 AU per year.

The primary soil type along the shoreline of the proposed pond is Collinsville stony loam (ER, Fig. 2.5-7). Based on the soil description (ER, Table 2.5-2), the staff believes this soil to have moderately low potential for erosion problems. Therefore, only rapid revegetation will be necessary only to maintain the structural integrity of the dam.

#### 4.1.1.3 Wastewater Holding Pond

A total of about 37 acres will be used for the wastewater holding pond. Included are two existing ponds that cover a total of four acres. The existing dam on the upper pond is higher (approximately 560 feet MSL; ER, Fig. 0-3.8-1) than the expected initial elevation of the water surface for the holding pond (about 553 feet MSL; ER, Supplement 0, Answer 3.8). The existing

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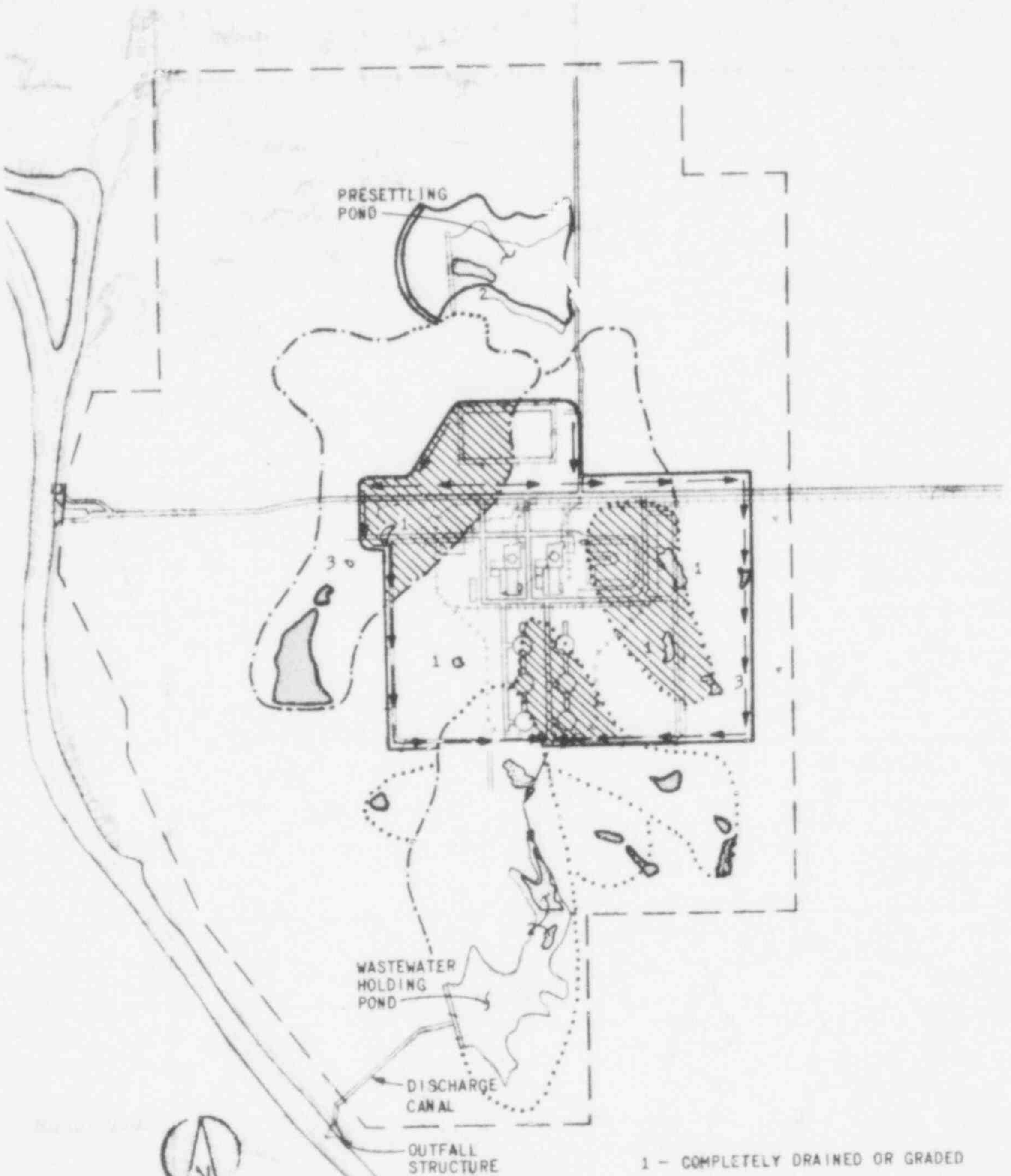


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Fig. 4.2. Modified Drainage and Surface Waters. Modified fror ER, Fig. 4.1-7.

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upper pond can serve as a wastewater holding pond until either (1) siltation fills its basin and the water overtops the dam, or (2) excess runoff from the central complex construction site due to intense rainfall overtops the dam.

The soils of the wastewater holding pond site are Breaks-Alluvial land complex, Taloka silt loam, Chouteau silt loam, Riverton loam and Riverton gravelly loam (ER, Fig. 2.5-7). The subsurface material (22 inches deep) of the Riverton gravelly loam is 50%-60% gravel (ER, Table 2.5-2) and therefore has some potential for subsurface drainage of the wastewater holding pond. The other soils are fine-textured, moderately to slowly drained soils (ER, Table 2.5-2) that are well suited to water ponding. The staff believes that the water-retaining ability of the wastewater holding pond could be improved by lining it with a layer of low permeability soils and will require that this be done. Rapid revegetation will be important in the maintenance of the structural integrity of the proposed dam.

#### 4.1.1.4 Historical and Archeological Resources

The cultural resources on the plant site include a historic cemetery and three prehistoric archeological areas (see Sec. 2.9). The applicant has made no commitments concerning the maintenance of the cemetery and has stated (ER, p. 2.6-6) that the archeological areas do not warrant preservation. It appears that the plant construction will not directly affect the cemetery or prehistoric areas.

The Oklahoma Archeological Survey (ER, Appendix 2D) recommended that the historic cemetery (RO-49) be preserved and that if construction activities are necessary in that area, the Indian tribe and State health authorities be consulted to facilitate movement of the internments to a satisfactory location. The staff concurs with this recommendation and believes that this cemetery should be preserved and protected if at all possible.

Areas covered by vegetation and surveyed by the walk-over method, particularly those areas in the construction zone, should be reexamined by another method. Any areas not examined in the original survey and located in potential construction areas should be carefully examined. Furthermore, all archeological sites must be investigated beneath the plow zone or "A" horizon for occupational debris and evidence of prehistoric settlement remains. The staff also requires that the applicant retain a qualified archeologist during the station construction phase to aid in the identification and preservation of historic and prehistoric cultural resources. The results of all archeological and historical field and laboratory studies should be made available in a final report.

### 4.1.2 Offsite

#### 4.1.2.1 River Intake Structure and Barge Slip

Both of these adjacent structures will be built on U. S. Government property administered by the U. S. Army Corps of Engineers. A total of 7.5 acres will be used under structures and for access roads. An additional 22 acres will be temporarily disturbed during construction for the disposal of spoils, primarily from the barge slip (ER, Supplement D, Answer 4.15). Subsequent to placement, these spoils will be stabilized by revegetation. All of the proposed spoil-disposal area is above an elevation of about 545 feet MSL. This is higher than the 536.8 feet MSL elevation below which a Corps of Engineers permit would be required.[2] However, a State permit may be required.[3]

The staff has estimated the relationship of the proposed spoil disposal area to flood stages of the Verdigris River to verify that the placement of the spoils affords reasonable protection to the Verdigris River from resuspension of the spoils by flood water. Because the Corps of Engineers regulates the flow of the Verdigris River to maintain the navigation pool elevation, river levels have fluctuated only slightly since the Newt Graham navigation pool was filled on December 26, 1970. The staff predicts the following flood stages:

| | At Newt Graham Lock & Dam | At BFS Spoils Disposal Area |
|---|---|---|
| Nominal pool elevation | 532.00 ft MSL | 534.31 ft MSL |
| 1 yr. flood | 532.56 | 534.77 |
| 50 yr. flood | 534.49 | 536.80 |
| 100 yr. flood | 534.63 | 536.94 |

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A producing oil well (averaging half a barrel per day; ER, Supplement 0, Answer 10.7) will be located within the proposed spoil-storage area (ER, Figs. 2.5-6 and 4.1-5). The staff requires that prior to any spoils disposal, plans for appropriate preventative measures to reduce the risk of oil leakage into these spoils be submitted for staff approval.

The applicant has not supplied the routing nor design for the system to transport water from the intake structure to the presettling pond. Prior to initiation of construction activities the applicant shall supply this information for staff analysis and approval.

The details of the river intake structure are discussed in Section 4.3.2.

4.1.2.2 Discharge Channel and Wastewater Outfall Structure

The wastewater holding pond will be connected to the wastewater outfall structure via a 70-feet-wide, lined channel (ER, Fig. 3.4-6) approximately half-a-mile long. Surface runoff will be diverted from its present course (an intermittent stream) below the proposed dam for the wastewater holding pond.

Some dredging of the Verdigris River and stabilization of the riverbanks will be required. The impacts of these are discussed in Section 4.3.2.

4.1.2.3 Railroad Spur and Access Roads

The 3.8-mile-long railroad spur and primary station access road will be located in the transmission corridor. Clearing and grubbing of 53 acres will be required for these routes. Earthwork for both the railroad and access road will involve less than 200,000 cubic yards of cut and fill, and 21,000 cubic yards of subgrade preparation. Drainage structures will be constructed over Inola Creek for both the railroad and the road, and over Pea Creek for only the railroad.

The applicant has made a commitment to seed, fertilize, and mulch the disturbed land along the railroad spur and access road (see Sec. 4.5.1). The staff recommends that seeding include a nurse crop and a mixture of native prairie grasses and forbs. Because of the erodability of the soils and the nature of the precipitation of the region, the staff also recommends the use of soil binders in order to stablize these disturbed lands. The use of soil binders in addition to mulching, fertilizing, and seeding is particularly recommended for the acreage to be reseeded along the major drainage structures.

The applicant indicates that one mile of an existing north-south county road onsite will be eliminated (ER, Fig. 4.1-8); approximately 5/8 mile will be eliminated by grading associated with the central complex. In the absence of a specific proposed plan for the removal of the remaining 3/8 mile of gravel road, the staff assumes that the road will be closed and abandoned. Because of soil compaction and the existing gravel surface, the staff further assumes that natural revegetation will be very slow, resulting in no appreciable reversion of the road to natural vegetation during the construction of BFS.

4.1.3 Transmission Lines

Public roads along about 80% of the proposed rights-of-way are laid out on a mile-square grid system. The applicant points out that this means transmission line structures will generally be existing field roads wherever practicable for access to these structure sites, and to use conservative access road construction practices (see Sec. 4.5.1). Although the applicant intends to "remove" the access roads constructed in connection with the BFS transmission system (ER, Sec. 4.2.2.1, p. 4.2-3), the staff has reservations concerning the effectiveness of any "road removal" program. The staff believes that contour plowing and/or disking to mitigate the effects of soil compaction and planting with native species (except in row crop agricultural land) would be equally effective, provided that access by off-the-road vehicles is restricted. The grading proposed by the applicant appears to the staff to be unnecessary, and perhaps more conducive to erosion than plowing and/or disking would be.

The soils throughout the BFS transmission system area are highly erodable either by surface water movement or by wind. This will have to be considered in constructing the transmission lines, especially at stream crossings (including intermittent streams). In particular, the staff recommends that installation and removal of stream crossing structures should be restricted to the autumn, when the probabilities of intense rainfall are low (ER, Sec. 2.3) and when there is sufficient time for planted nurse crops to become established prior to the spring storms. In addition, wherever the soil is disturbed on slopes, terracing to reduce the rate of runoff should precede reseeding.

719 030 718 243

Agricultural usage of the transmission ROW will be interrupted during construction. One season's crop production will be lost on a total of about 460 acres of cultivated land because of construction. A possible residual impact is a reduced yield on the disturbed acreage for a few seasons. The staff believes that the cost of verifying this possible reduced yield would exceed the market value of the agricultural productivity lost. The interruption of livestock production on pastureland will amount to the temporary displacement of animals from about 2400 acres during periods of construction activity, and a somewhat reduced forage productivity for the remainder of the growing season. The towers and poles will occupy a small percentage of the total ROW acreage, resulting in a small permanent loss of agricultural usage. For a 150-foot-wide ROW with an average tower spacing of 5.28 tower bases (each 50 feet square) per mile, this amounts to 1.6% of the acreage. For wood poles with five-foot-square bases and an average spacing of 7.54 poles per mile, this is only 0.1% of the acreage. For pasture land, the permanent loss of productivity is one animal unit (AU) per 20 miles of ROW using steel towers and one AU per 333 miles of ROW using wood poles, or approximat.ly 1.5 AUs for the entire BFS transmission system per year.

A major adverse impact on terrestrial ecosystems will occur in the mesic forests, where the selective clearing practices proposed by the applicant will result in a drying effect due to increased exposure of the communities to wind and to insolation, and due to increased transpira- tion from the proposed planting of grasses. Since the staff believes that unique mesic habitats such as described in Section 3.7.3, are likely to be present in the path of the proposed ROW, Sections XId, XIe, XIIa and XIIb it is required that the proposed transmission routing in these sections be inspected by a qualified biologist to verify if such habitats are present. If such is found to be the case, the applicant will be required to either span such habitats, avoid them by changing the ROW alignments, or submit for staff approval, prior to construction, a program to mitigate the potential adverse effects. If the offset ROW alignments differ from the reference alignments by more than one-half mile, additional ecological information must be submitted for staff review and approved prior to initiation of construction in the new ROW.

A total of 992.8 acres of woodland will require some clearing during construction of the trans- mission lines. Marketable timber removed will be sold, thereby partially offsetting the com- mitment of forest resources for the life of the plant imposed by ROW maintenance. The brushy habitat that w... develop in response to the continual ROW maintenance will maintain a diversity of habitats alo... wooded portions of the ROW. The ecological consequences of this change from woodland to bushy habitat are (1) the loss of some individuals of species presently utilizing the woodland habitats, and (2) a potential increase in abundance of those species that utilize disturbed or successional woodland habitats.

Although visual impacts will result throughout the entire transmission system, the staff believes that persons using recreational areas are particularly sensitive to these impacts. Along the Verdigris River, there are seven U. S. Army Corps of Engineers Public Use Areas of concern. ROW Section III will be clearly visible from two of these (Channel View and Bluff Landing) and perhaps from two others (Commodore Landing and Rocky Point). The Grand (Neosho) River crossing (ROW Section XIc) will be visible from a Corps of Engineers Public Use Area (Low Water Dam). There are two planned recreational/retirement residential developments near the proposed trans- mission corridors: Flint Ridge, which will cover 6900 acres along the Illinois River south of ROW Section XIe; and Bella Vista, which is an extensive development (the staff estimates 33,000 acres) southeast of ROW Section XIIb in Arkansas. In addition, Huckleberry Ridge State Park is less than one mile northwest of ROW Section XIIb in Missouri. The staff observations at the site visit verified that the unavoidable visual impacts of transmission lines in the flat topography and low vegetation of Oklahoma extend as much as 2.5 miles from the lines.

Construction of transmission line corridors will necessitate about 40 crossings of permanent water bodies, mostly creeks, and about 140 crossings of intermittent streams. Construction activities may result in the addition of solids to these bodies of water and disruption of their substrates. Also, adverse impacts could result from debris (such as cleared vegetation) placed in the water and from runoff of herbicides. The impacts on fish at the crossings are discussed in Section 4.3.2.

The applicant has agreed to the inspection of the transmission routing by an archeologist to verify that no significant archeological or historical sites are to be disturbed (see Sec. 4.5.1). The staff also requires that an archeological and historic site survey be made for all areas where tower bases are to be located, where roads are to be built, and where transmission line construction will disturb existing soil cover. Staff requirements on prehistoric and historic cultural resources presented in Section 4.1.1.4 are also applicable to any site in the transmis- sion corridors to be disturbed or destroyed. The results of archeological and historical investigations should be presented in a final report.

The applicant must consider any scenic area or scenic river that might be within viewing distance from the transmission lines. Particular attention is called to Flint Creek/Illinois River areas.

### 4.1.4 Radiation Exposure to Construction Personnel

During the period between the startup of Unit 1 and the completion of Unit 2, the construction personnel working on Unit 2 will be exposed to sources of radiation from the operation of Unit 1. The applicant has indicated that this radiation exposure will be maintained "as low as is reasonably achievable" through administrative procedures, physical barriers, locked buildings, and radiation monitoring.

The main sources of radiation exposure to the workers will be gaseous effluents from Unit 1 and scattered direct radiation from the nitrogen-16 in the Unit 1 turbine. The applicant has estimated that the Unit 2 construction force will receive 80 man-rem due to the operation of Unit 1. This estimate falls within a range of values predicted for plants of similar design and the staff concludes that this estimate is reasonable.

## 4.2 WATER USE

Site construction activities that can affect surface waters include grading and filling, excavating for pipelines and foundations, and constructing barge slip, intake, and discharge facilities. These operations will alter site drainage patterns and modify erosion rates. Although the applicant will take measures to minimize erosion, some temporary increases in sediment load, siltation, and turbidity in the Verdigris River and Inola Creek will be unavoidable during the construction period.

Verdigris River water requires treatment before use as a public supply. The nearest public water supply intake, three miles downstream of the site, is for the Broken Arrow water system. The system draws water from a backwater pool that is off of the main navigation channel and undergoes little mixing with the main channel. The additional sediment load caused by BFS construction will be carried primarily in the channel, and consequently will have little effect on the Broken Arrow water supply. Construction water use will be intermittent and will peak at about 1.0 cfs, which is 2.5% of the minimum recorded low flow (40 cfs) and only 0.05% of the median flow (2000 cfs) at Newt Graham Lock and Dam. Hence, use of water during plant construction is not expected to have any adverse impacts on water supply.

Navigation on the Verdigris will not be hindered because of construction of station facilities. The barge slip, intake, and discharge construction operations will be confined to shoreline areas and usually will not encroach into the main navigation channel. Recreational activities on the river are not expected to be affected other than by the visual and esthetic obtrusions caused by the presence of construction equipment.

About nine of the 30 existing onsite ponds will be affected in varying degrees by construction activities. Because general access to the station area will be restricted, the remaining ponds will not be used for stock watering or fishing.

Although excavation dewatering is presently not expected, if it is later found to be necessary, it will not affect groundwater use beyond the site boundary. In such a contingency, groundwater levels will be temporarily lowered locally, but will return to normal after completion of construction.

## 4.3 ECOLOGICAL IMPACTS

### 4.3.1 Terrestrial

The impacts of construction activities on the terrestrial biota of the BFS site and the immediate vicinity are discussed below. The ecological impacts related to construction of the transmission lines are discussed in Section 4.1.3. Those activities that begin during construction and continue for the life of the plant are considered plant operation-related and are discussed in Section 5.6.1.2.

#### 4.3.1.1 Vegetation

All vegetation will be removed within the construction areas. (Table 4.1 gives the acreage disturbed.) Much of this land presently supports lowland improved pasture. This is the biotic community type that has been most disturbed by grazing. No areas of greater grazing disturbance were observed by the staff in those portions of Rogers County that were seen during the site visit. The ultimate heat sink impoundment and about half of the cooling towers will be built on land presently occupied by prairie hay. Prairie hay more closely resembles the tall-grass native prairie than do any other onsite grasslands (see Sec. 5.6.1.2). The loss of this community is considered to be an adverse impact.

The switchyard will be built on land presently occupied by low and unimproved pasture. This is presently disturbed somewhat by grazing. The loss of this community can be considered to be a commitment of land with moderate potential for prairie restoration (see Section 5.6.1.2) to other uses.

The presettling pond will displace primarily shrub-invaded grasslands. Some of the invading woody species appear to be indicators of overgrazing, while others are indicative of succession to woodlands (based on staff observations at the site visit and interpretation of the ER, Sec. 2.2.3.1.5.2, p. 2.7-77).

The wastewater holding pond will displace primarily xeric upland woods. The applicant indicates that 25 acres may be disturbed, but that only 15 acres will be cleared to construct the minimum operating pool and access (ER, Supplement 0., Answer 4.12). However, xeric upland woods species are highly intolerant not only of flooding, but even of saturated soil. The staff expects that the minimum destruction of woodlands will extend to at least the original figure of 25 acres. Even if the larger estimate of acreage lost is correct, the staff agrees with the applicant that this location is environmentally preferable to the alternative described in the ER, Supplement 0, Answer 4.12. The alternative location is in an area where prairie restoration is possible (Sec. 5.6.1).

The staff finds the applicant's proposed revegetation plan (ER, Sec. 4.5.1.5, and Supplement 0, Answer 4.6) to be acceptable. The staff believes that several specific areas may require the planting of Bermuda grass for rapid revegetation. These include, but are not limited to, (1) the earthen dams on the presettling and the wastewater holding ponds to insure the structural integrity of these dams, (2) the embankments around the central complex site where natural drainage will be rerouted to parallel the embankment, and (3) the draw that will carry surface runoff from the central complex site to the wastewater holding pond. Since the Bermuda grass will outcompete native species, then become root-bound within a decade (ER, Supplement 0, Answer 4.6), the staff recommends that at the end of the construction stage a native seed mix be broadcast into those areas planted to Bermuda grass by the applicant. This will improve the likelihood that native habitats will develop.

#### 4.3.1.2 Fauna

Most wildlife will be excluded from the construction sites by habitat destruction. The only exceptions are the omnivores, such as skunks and raccoons, which may search the construction areas at night for edible debris left by construction workers. Additional displacements of wildlife from undisturbed areas adjacent to construction sites are expected as a result of noise and of the movement of men and machines. The staff analysis indicates the existence both of potentially suitable habitat and of migration pathways to these habitats for the displaced individuals. The staff predicts that the removal of livestock from the unaffected portions of the BFS site will lessen competition and interference with wildlife. Therefore, the wildlife displaced by construction activities can migrate onto these portions of the site without encountering strong competition. The only possible exceptions are those animals which are sufficiently sensitive to noise that they migrate completely off the BFS site. These animals will face stronger competitive pressures, probably resulting in the loss of many individuals. Losses of individual animals due to road kills will increase as a result of construction traffic and increased commuter and recreational traffic due to the anticipated temporary human population increase.

In conclusion, the staff has considered the terrestrial impacts which will result from constructing the BFS at the reference site, and, on the whole, considers these impacts acceptable if appropriate measures and controls detailed in Section 4.5 are implemented.

### 4.3.2 Aquatic

#### 4.3.2.1 General Overview

Biological communities in the Verdigris River, Inola Creek, and onsite ponds will be influenced in varying degrees by site preparation and station construction. Effects of construction runoff on the involved aquatic systems will be minimized by channelization and collection of water from areas disturbed by excavation and grading. The applicant will build a system of ditches and dikes and a wastewater holding pond to control erosion as committed to in the ER, Figure 4.1-6 (see Sec. 4.5.1). Except for the biota in what is to become the wastewater holding pond and in a few of the existing onsite ponds, adverse construction impacts are expected to be minor, temporary, and reversible. Construction impacts will be minimal on fish populations of the Verdigris River and of creeks in the site vicinity, and will have little, if any, effect on the rare species reported in Section 2.7.2.8. These rare species (highfin carpsucker, goldeye, and Kiamichi shiner) were not collected in the onsite ponds sampled and are thus assumed not to be present in the nine onsite ponds to be affected by construction activities.

4.3.2.2 Verdigris River

Construction of the river intake structure, barge slip, and outfall facilities will not eliminate or degrade productive aquatic habitats or interfere with fish movements in the river. There will be localized construction dredging that will temporarily introduce additional silt into the river. Although detrimental effects of siltation are well documented,[5-9] effects from BFS construction activities should be minimal because of the short duration of construction and the presence of a naturally occurring suspended solids load (ER, Table 2.4-2). Additionally, the effects of river impoundment[10-12] and channelization and of maintenance dredging[12,13] have destroyed natural habitats. As a result, the Verdigris River in the BFS area now supports a sparse biotic community (ER, Sec. 2.2.3.2). Furthermore, any detrimental siltation effects will be restricted to only a portion of the Verdigris on the side where the BFS is located. This will permit maintenance of a biotic channel down the rest of the river, thus allowing natural distribution of organisms along the length of the river and providing a source for recolonization.

The applicant found no evidence that fish spawn in the areas proposed for the intake, barge slip, and outfall facilities; the numbers of pelagic fish eggs and larvae collected in the area of the proposed intake were low (Sec. 2.7.2.2, and ER, Tables 2.2-122 and 0-2.45-3) The applicant, nevertheless, will be required to use conservative measures to protect the fish, benthos, and plankton. Sheetpile protection will be constructed on either side of the intake to establish or help maintain bank stabilization. The applicant should construct a temporary cofferdam in the river prior to the dewatering process necessary for building the intake structure. The process is expected to last six months (ER, p. 4.1-22). Dredged or excavated materials will not be intentionally placed in the river. The intake and related structures will be located on the bank to preserve streamline river flow without obstructing existing flow or navigation.

The applicant states that spoil from underwater excavation of medium-textured sediments at the barge-slip area will be immediately moved onto the designated site spoil deposit area (ER, Fig. 4.1-5) to prevent excessive siltation of the river (ER, p. 4.1-8). Verdigris River banks disturbed as a result of the barge-slip accessway construction will be subject to erosion by waves and surface runoff. This would increase river sediment loads by undercutting and eroding unstabilized banks. The applicant plans to plant Bermuda grass to minimize this effect (ER, p. 4.1-8). Based on the evaluation given in Section 4.3.1 of this Statement, however, the staff recommends the use of a nurse crop, such as rye, as a substitute for Bermuda grass in these areas. The staff also recommends the installation of sheetpiling on both sides of the entrance area to the barge slip if high rates of erosion are observed.

Installation of the wastewater outfall (discharge) structure is not expected to cause adverse impacts on the river biota; however, the staff requires that the applicant use conservative dredging procedures to minimize siltation (e.g., dredged material will be immediately moved to a designated spoil-deposit area and dredged materials will not be intentionally placed in the river). Rip-rap will be used to stabilize the adjacent shoreline to prevent sloughing of bank material. A temporary cofferdam will also be installed to reduce erosion. Additionally, erosion protection will be provided on the side slopes of the discharge canal leading from the wastewater holding pond to the outfall structure.

Any clearing of vegetation on the Verdigris River banks in the areas of the intake, outfall, and barge slip will be performed so as to leave root structures undisturbed in an attempt to maintain bank stability.

Terraces, intercept ditches, and/or other control devices will be built where necessary along the main site drainageways and along the Verdigris River banks to help prevent siltation and erosion.

The applicant has not identified the methods that will be used to (1) dredge, (2) dispose of the dredged material in the designated spoil-deposit area, or (3) contain the spoil material before covering it with topsoil and planting stabilizing vegetation. With no precautions taken to control runoff from the spoils area, erosion and resulting siltation could lead to major degradation of aquatic ecosystems.[5-9,14] The staff suggests that a containment structure, e.g., a dike system (see Sec. 4.1.2.1), be constructed completely around the spoil-deposit area. Also, runoff will be monitored (see Sec. 6.1.3) to insure that total suspended solids do not exceed 50 mg/l. The applicant also has not indicated the methods to be used in the dredging, disposal, and containment of material from the construction of the outfall structure. Therefore, the applicant must use conservative construction practices for the proper disposition of dredged material in the area of the outfall.

Because of the high lime content of wastewater resulting from washing of aggregate, concrete lift operation, washing of concrete trucks, and batch plant operation, caution must be taken to ensure that there will be no long-term chronic or short-term deleterious damage to aquatic biota due to changes in pH. The staff recommends that means be provided to prevent such impacts, such as the installation of a small sediment basin between the wash area and wastewater holding pond and the construction of a small holding pond for the batch plant effluent for settling of solids and, if needed, adjustment of pH. The applicant should also ensure that any chemicals released to the Verdigris as a result of chemical cleaning prior to unit startup have been neutralized or diluted to meet applicable standards.

The wastewater holding /pond will be used to retain site runoff, effluent from the sewage treatment plant, and other miscellaneous wastewater during construction. The discharge structure will control the release rate and will include an overflow feature (ER, Fig. 3.4-5). Means must be provided to prevent discharge of grease, oil, and/or suspended solids, such as the installation of a skimmer. The applicant has stated that all effluents from the wastewater holding pond, other than "untreated overflow," will meet the total suspended solids limitations (EPA) of 50 mg/l and the pH limitation of 6.0-9.0 (ER, p. 4.5-2) provided by the "Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category," 40 CFR § 423.43 (ER, Table 12.1-3). The staff assumes that the "untreated overflow" would consist of materials storage runoff and construction runoff, as well as rainfall runoff that would be in excess of the 10-year, 24-hour rainfall (6.3 inches) capacity of the wastewater holding pond. The "untreated overflow" would be a potential source of contamination to the Verdigris River system or to terrestrial areas because of suspended solids, chemical effluents, and other materials, and is considered an unavoidable impact. It is concluded that during construction, effluents from the wastewater holding pond will have minimal ecological impacts to Verdigris River biota, providing the applicant complies with applicable limitations and regulations, as well as specific staff requirements (Sec. 4.5.2) and the applicant's commitments (Sec. 4.5.1).

4.3.2.3 Onsite Ponds

Nine of the 30 onsite ponds will be directly or indirectly affected by construction activities (ER, pp. 4.1-19 through 4.1-21). Four small, shallow ponds in the central complex area will be eliminated during earth-moving operations. These ponds are turbid and have not been attractive to anglers, recreationalists, or waterfowl. Direct and indirect detrimental effects of turbidity have been shown in farm pond fish,[15] as well as in other aquatic organisms.[16-19] The poor quality of the majority of onsite ponds is, in large part, a result of high turbidity. The ponds possess no unusual species assemblages. Low diversity (between 1.00 and 3.00) and stunted fish were observed in the smaller onsite ponds (Aquatic Stations 6 and 7).

Two onsite ponds will be incorporated into the wastewater holding pond. Since construction runoff will be routed to the holding pond, the organisms in these existing ponds will be subject to the effects of siltation. Because of unfavorable ranges and variabilities in chemical and physical qualities of the water, many species surviving the construction impacts probably will be killed during the operational phase when station effluents are retained in the holding pond. Current species composition is thought to be similar to Aquatic Station 6, and thus the loss of the aquatic life in these two ponds will not be considered of major importance. One pond (Aquatic Station 7) will be incorporated into the presettling pond. Construction of the dam for the presettling pond should not adversely affect the physical, chemical, or biotic parameters of the pond. During station operation the size of the pond will increase from 3.5 to 30 acres. A new aquatic ecosystem will be created because of the influx of Verdigris River organisms after station operation begins.

Containment of surface runoff within a system of ditches will reduce the quantities of runoff reaching two onsite ponds near the central complex area. These ponds may have lower water levels than similar ponds during years of lower-than-normal precipitation, and during drought conditions they will probably dry up sooner than other shallow ponds.

The removal of cattle from the site should be of minor benefit to the remaining onsite ponds. This action will reduce turbidity caused by wading and will increase light penetrability, thus increasing primary productivity. Organic loading from cattle feces will also decrease. Additionally, pond bank stabilization will result, permitting growth of macrophytes and pond-edge vegetation.

4.3.2.4 Stream Crossings

Railroad Spur and Access Roads

Because drainage from the main construction area will be routed to the wastewater holding pond and then to the Verdigris River, effects of preoperational activities (other than in transmission corridors) will be restricted to temporary increases in silt load during construction of the railroad spur and an access road over Inola and Pea Creeks. Since sediment resulting from soil erosion is regarded as the largest pollutant that affects water quality,[14] construction practices described in the ER, Section 4.5, will be followed to reduce siltation effects (see Sec. 4.5).

To minimize any effects on fish moving to upstream spawning locations, no creek crossings will be constructed during the spring or early summer. The staff requires that such crossings be constructed during the dry seasons, and not during periods of high water or rain. Also, creek crossings will be constructed during low flow so that potential impacts will be confined to the immediate area. Additionally, to keep siltation problems to a minimum, the applicant intends to construct trestles during dry weather; the staff requires that the access road crossing also be constructed during dry weather. Locally, macroinvertebrates will be smothered, but organisms from upstream and downstream[20,21] should repopulate the affected areas following a high flow, which should flush the silt from the stream. Generally, construction-related siltation should be similar to the natural turbidity and siltation caused by flooding (ER, p. 4.1-21).

Permanent stone rip-rap will be used for stream-bank stabilization adjacent to timber pile trestles (ER, p. 4.5-10). Creek crossings will be designed to avoid restrictive streamflow (ER, p. 4.1-9).

Since the applicant will not use growth retardants, chemicals, biocides, sprays, and other such materials during transmission corridor right-of-way clearing (ER, p. 4.2-4), the staff assumes that these materials will not be used at railroad and access road crossings. If, however, the applicant intends to use any such materials, a full description (including types, quantity, and concentration) of compounds to be used shall be submitted to the staff for review and approval prior to use. In no case shall herbicides be applied within 200 feet of water bodies. Clearing in the vicinities of Pea and Inola Creeks will be performed so as not to disturb the root structure of existing growth. Because of the possible deleterious effects of decaying slash[22] and leaves,[23] the staff requires that precautions be taken to prevent cleared vegetation from entering the creeks. Materials will be disposed of in the manner stated in the ER, p. 4.1-3, and summarized in Section 4.5.

Dust resulting from construction activities would have similar effects, if deposited into aquatic systems, as construction erosion runoff, i.e., cause increased turbidity and siltation. Therefore, the applicant is required to take measures to control dust concentrations near areas of creek crossings. The staff recommends that only water, crushed rock surfacing, cover-crop planting, and calcium chloride be considered for use in dust control.

Transmission Lines

As mentioned in Section 4.1.3, a number of waterways will be crossed by transmission lines constructed in conjunction with BFS. Because a number of rare and endangered fish species (Table 4.2), as well as other aquatic biota inhabit the streams and creeks to be crossed, steps will be taken during construction to minimize adverse environmental effects and to contain any effects within the immediate construction vicinity. The staff will require that the following procedures be followed: (1) crossings over biologically productive waterways shall be constructed during dry seasons, not during fish spawning seasons or periods of high water or rain; (2) a 100-foot-wide buffer zone of undisturbed vegetation (except for selective removal of taller trees) shall be left on each side of the waterways crossed; (3) cleared vegetation shall not be placed in the streams; (4) tower bases shall be located above floodplains where practicable, and (5) herbicides shall not be applied within 200 feet of water bodies. Additionally, the applicant has committed to selecting vehicle and equipment access routes that will avoid damage to stream banks (see Sec. 4.5.1). The staff concludes that transmission line construction impacts on aquatic biota at waterway crossings will be minor, short-termed, and reversible providing the above-mentioned practices are followed.

Conclusion

The staff has considered the potential aquatic impacts of constructing the BFS at the reference site and concludes that, in total, they are acceptable if appropriate measures and controls detailed in Section 4.5 are implemented.

Table 4.2. Rare and Endangered Oklahoma Fish Actually or Potentially Present in Waterbodies To Be Crossed by BFS Transmission Line Corridors

| Species and Status[a] | Locality |
|---|---|
| Endangered | |
| Arkansas darter | Confined to extremely specialized habitat of spring-fed streams containing watercress in Neosho River drainage |
| Shovelnose sturgeon | Eastern portion of Arkansas and Red Rivers |
| Rare (R1) | |
| Bigeye chub | Arkansas River drainage |
| Pallid shiner | Eastern tributaries of Arkansas River |
| River shiner | Arkansas and Red River systems |
| Spotfin shiner | Illinois River |
| Ozark cavefish | Cave streams in northeastern Oklahoma |
| Blackside darter | Eastern Oklahoma |
| Longnose darter | Poteau River and Lee's Creek (Arkansas River drainage) |
| Rare (R2) | |
| Highfin carpsucker | Larger streams of Arkansas and Red River systems, Ft. Gibson Reservior, Lake Texoma, and Grand Lake |
| Blue sucker | Lake Texoma and Grand Lake |
| Pealip redhorse | Eastern tributaries of Arkansas River system |
| Bluntface shiner | Northeastern corner of Oklahoma |
| Kiamichi shiner | Kiamichi River, Little River system, and Poteau River of Arkansas River system |
| Neosho madtom | Neosho River drainage and Illinois River |
| Plains topminnow | Neosho and Illinois River drainages |
| Yellow bass | Eastern and southeastern portions of Oklahoma |
| Least darter | Eastern Arkansas River drainage and Blue River of Red River system |
| Status Undetermined | |
| Goldeye | Arkansas and Red River systems |
| "Other"[b] | |
| White sucker | Known only from Spring Creek in Mayes County in Oklahoma |

[a]Information derived from Rare and Endangered Species of Oklahoma Committee, "Rare and Endangered Vertebrates and Plants of Oklahoma," 1975; except for "Other."

[b]Listed as rare by Blair, "Report on Areas of Ecological Significance in Eastern Oklahoma," Appendix B, In: Sargent and Lundy Report, SL-2864, Nuclear Station Site Selection Study-Phase 1, 1972.

## 4.4 IMPACTS ON THE COMMUNITY

### 4.4.1 Physical Impacts

Six of the ten residential structures within the site boundary will be removed during the construction of Unit 1 (ER, Sec. 2.1.1, p. 2.1-2). The remaining four will be used for construction purposes (shops, storage, etc.).

Two existing gravel roads in the main construction area will be affected by construction activity: a north-south county road will be closed to the public but may be used as an emergency access route after station construction is completed, and an east-west county road will be improved for access to the railroad station (ER, p. 4.1-4). A quarter-mile of railroad spur will be constructed offsite, parallel and adjacent to the east-west county road (ER, Sec. 4.1.1.3.3). Construction of the rail spur and upgrading of the east-west county road will occur simultaneously. This activity will come within 400 feet to a residence (ER, Supplement 3, pp. 4.1-13). The noise from the rail spur and site construction would constitute a nuisance to the resident and the users of public use area including the proposed Channel View Public Use Area.[27] Occupants of those residences will also be subjected to noise from trains using the railway spur after it is completed. Rail deliveries are expected about three times per week.

### 4.4.2 Traffic

Construction traffic will cause some congestion on local arterial and access roads, especially at the intersection of State Highway 33 and the Newt Graham Lock and Left Abutment Dam Access Road. The applicant estimates that there will be a one-way average of 800 and a peak of 1500 additional vehicles per day associated with construction of the BFS. In addition, construction truck traffic is expected to vary from 20 to 100 vehicles per day (ER, Sec. 4.1.1.4.5). For the most part, however, the BFS work-force traffic on Highway 33 will be moving in the opposite direction of the predominant peak-hour commuting traffic from Inola Township to the Tulsa area. Assuming that the enlargement of Highway 33 to four lanes is completed as planned before site construction begins, the additional traffic caused by the BFS project will not be a serious problem insofar as maintaining the level of service planned by the State of Oklahoma for rural/urban areas.

### 4.4.3 Impacts on Regional and Local Employment, Income, and Production

The applicant utilized regional "input-output analysis" to estimate economic impacts within the 100-square-mile region around BFS (see Fig. 4.3). In an input-output analysis, the assumption of constant technological coefficients is a critical limitation, and the applicant made no attempt to account for this limitation. Nevertheless, the staff believes that regional employment, production, and income impacts predicted by input-output analysis are adequate as approximations.

As shown in Table 4.3, construction will take about eight years. Most of the BFS workers commuting to the site will live within an area of about 10,000 square miles, which includes 17 Oklahoma counties and the Tulsa metropolitan area. During 1981, the peak year of construction, 2133 workers are expected to be employed. As a result of a multiplier effect, the direct and indirect employment in 1981 is expected to be 4881, which is about one percent of the total regional employment projected for that year. The applicant's estimates of annual primary and total employment effects in the region are shown in Table 4.3.

In the peak year of 1981, the direct and indirect output requirements due to the BFS construction are estimated at about $129 million, which is more than one percent of regional output. The primary and induced regional income and production impacts are shown in Tables 4.4 and 4.5, respectively.

Table 4.3. BFS Construction and Operation Work Force and Employment Impacts

| Year | Average Construction Work Force | Operating Crew | Total Employment Impact[a] |
|---|---|---|---|
| 1977 | 30 | -- | 124 |
| 1978 | 358 | -- | 1224 |
| 1979 | 930 | -- | 2738 |
| 1980 | 1933 | -- | 4555 |
| 1981 | 2123 | -- | 4881 |
| 1982 | 2023 | -- | 4278 |
| 1983 | 1465 | 95 | 2547 |
| 1984 | 350 | 95 | 761 |
| 1985 | 0 | 136 | 261 |
| 1990 | -- | 136 | 255 |
| 2000 | -- | 136 | 255 |
| 2010 | -- | 136 | 255 |
| 2020 | -- | 136 | 255 |

Modified from ER, Tables 8.1-17 and 8.1-23.

[a]Includes direct and induced employment in the entire region.

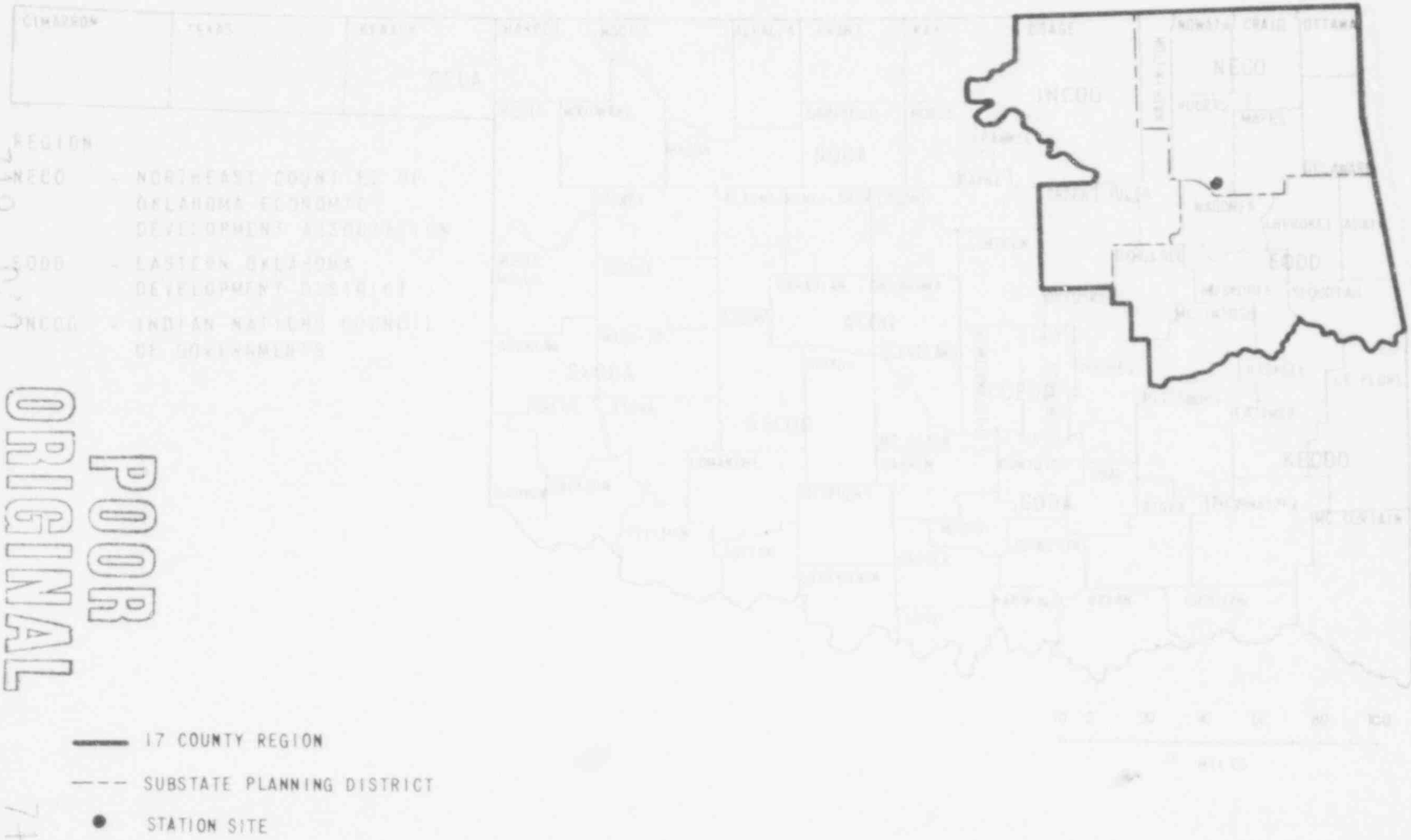


Fig. 4.3. Substate Planning Districts of Oklahoma. From ER, Fig. 8.1-2.

Table 4.4. BFS Regional Personal Income Impacts
(thousands of current dollars)

| Year | Construction Payroll Impact | Operating Payroll Purchase Impact | Construction Total Impact | Impact |
|---|---|---|---|---|
| 1977 | 3,634 | -- | 50 | 3,684 |
| 1978 | 36,366 | -- | 25[illegible] | 36,717 |
| 1979 | 78,308 | -- | 2,183 | 80,491 |
| 1980 | 112,144 | -- | 8,175 | 120,319 |
| 1981 | 114,737 | -- | 15,123 | 129,860 |
| 1982 | 105,523 | -- | 15,549 | 121,072 |
| 1983 | 46,932 | 3,693 | 4,158 | 54,783 |
| 1984 | 11,759 | 3,877 | 1,763 | 17,399 |
| 1985 | -- | 5,828 | 202 | 6,030 |
| 1990 | -- | 7,408 | -- | 7,408 |
| 2000 | -- | 12,115 | -- | 12,115 |
| 2010 | -- | 19,734 | -- | 19,734 |
| 2020 | -- | 32,147 | -- | 32,147 |

From ER, Table 8.1-25.

Table 4.5. BFS Regional Economy Output Impacts
(thousands of current dollars)

| Year | Construction Force Impact | Operating Force Impact | Construction Purchase Impact | Total Impact |
|---|---|---|---|---|
| 1977 | 3,185 | -- | 93 | 3,278 |
| 1978 | 31,848 | -- | 468 | 32,316 |
| 1979 | 68,619 | -- | 4,084 | 72,503 |
| 1980 | 98,267 | -- | 15,279 | 113,546 |
| 1981 | 100,374 | -- | 28,264 | 128,638 |
| 1982 | 84,216 | -- | 29,062 | 113,278 |
| 1983 | 41,125 | 3,236 | 7,769 | 52,130 |
| 1984 | 10,304 | 3,397 | 3,292 | 16,993 |
| 1985 | -- | 5,107 | 378 | 5,485 |
| 1990 | -- | 6,518 | -- | 6,518 |
| 2000 | -- | 10,616 | -- | 10,616 |
| 2010 | -- | 17,292 | -- | 17,292 |
| 2020 | -- | 28,169 | -- | 28,169 |

From ER, Table 8.1-27.



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The annual per capita income in Inola Township is low ($2400), and the unemployment rate has been high (21% in 1972). In 1972, about 64% of those employed were reported to be working in the Tulsa area.[24] Construction of BFS will create job opportunities for skilled and unskilled residents of the area. In absolute terms, the economic impacts of BFS construction and of the income multiplier may not be very large in the communities in the immediate site vicinity. Most workers are expected to live and to spend their money outside these smaller communities (in Tulsa, for example), and most equipment and material for the plant will be purchased outside the immediate area. However, on a per capita basis, the impact on the loca economy by the workers who do live in the nearby communities will be relatively visible in terms of induced employment opportunities and commercial activities.

### 4.4.4 Population Increases and Community Impacts

The applicant estimates that during the peak construction year (1981), labor-force relocation will result in population increases of 330 in the site vicinity (within about five miles of the site) and 660 in the region within 50 miles of the site by assuming an additional population/ immigrant worker ratio of 3 to 1. The applicant's estimates of total population impacts in the site vicinity (ER, Table 8.1-19) are based on maximum quarterly average project employment, while regional impacts (ER, Table 8.1-20) are based on annual average project employment. The staff suggests that the applicant reconcile these two projections by using a common base.

The magnitude of the population effects in a commuting area depend upon such factors as regional labor market and economic conditions. The number of workers deciding to move to communities closer to the BFS site will depend upon such factors as commuting road networks, available modes of transportation to the site, local housing and tax situations, community services, and other amenities. The presently available information is insufficient for the staff to predict either the proportion of the workers who will move into the commuting area or their settlement pattern within that area. Because the staff believes that the size of the immigrating population is most critical in assessing the socioeconomic impacts on the communities in the immediate vicinity of BFS, a conservative assumption of the number of immigrating workers is desirable for the examination of the population impacts. Such assumptions are used in the following discussion.

In 1970 there were only 26 vacant housing units in the town of Inola. Without substantial increases of housing supply in that area, most of the immigrant workers will be forced to live in the communities more than 10 miles from BFS--Catoosa, Claremore, Broken Arrow, or Tulsa (which alone had 12,119 vacant housing units in 1970). The applicant believes that the housing demand of migrant workers will be filled by a mix of rental properties, rooming homes, and mobile home parks.

Inola School District (I-5) has one high school, one junior high school, and one elementary school. Including one other elementary school located within five miles of BFS, the current school enrollment in this area is about 860. Assuming that 10% of the construction workers decide to move to this area, school enrollment may increase by more than 200, which is approximately 25% of current enrollment. To maintain the current operational characteristics of the Inola School District, and assuming an even distribution of children among all grade levels, the additional enrollment would create a need for approximately ten teachers, eight classrooms, and four buses.

Since schools in this area have no large excess capacities, this impact will likely create a need for new school facilities not only in Inola, but possibly in other small communities within a 20-mile radius. However, the magnitude of needs for school facilities in those communities could vary widely, depending on the immigrant settlement pattern (which in turn will be heavily influenced by accessibility and housing conditions). The Tulsa metropolitan area is within commuting distance from the BFS site (about 23 miles). Although it is possible that a majority of immigrating workers would settle in the metropolitan area, the staff believes that the potential exists for stress on school facilities and services in the communities closer to the site.

The closest medical facilities are in Claremore, about 14 miles from the site. Claremore Health Center has 103 beds, with approximately 60% occupancy. There are ten doctors, one radiologist, and a supporting staff of about 200. Indian Hospital, also in Claremore, serves primarily Indian patients. It has 66 beds. Grand Valley Hospital and Mook Osteopathic Hospital are also within 20 miles of BFS. The staff concludes that there are sufficient hospital services available in the vicinity of the BFS site to support the construction force under ordinary circumstances. In the event of unusual circumstances, facilities in Tulsa can be used.

The impacts of BFS activities along with other sources of growth in the region would be felt in the cities of Rogers County including Claremore, Tulsa area, and Wagoner and Mayes Counties. For example, the applicant's Northeast coal fired power plant construction activities would have some cumulative effect on housing, school system, and other local facilities in the city of Claremore and also commuting roads from/to the two activity locations (e.g., Highway 88 and 33). However, based on the staff's investigation, the combined effects on local facilities in the threshold areas ould not be great enough to create bottlenecks which can not be alleviated by monitoring and mitigating programs.

The applicant claims that in 1986 BFS will account for approximately 98% of the projected Inola School District ad valorem tax base and ad valorem tax revenues (ER, Sec. 8.1.4.5).

Assuming that tax rates are not affected by the presence of BFS, the applicant estimates that between 1974 and 1986 it will pay a total of $101,370,000 in constant-dollar ad valorem taxes (ER, Table 8.1-28). Most of the total will be contributed toward the end of the construction period when the value of the property on the site increases dramatically. Since ad valorem revenues from the BFS vicinity during the 1974-1986 period are projected to be $45,600 without the plant (ER, Table 8.1-28), the plant will provide more than a 2000-fold increase in local revenue during the construction period.

The applicant's estimate of ad valorem tax revenues per year from 1986 (just after full power production begins) to 2020 (at decommissioning) is $27,912,000 (ER, Table 8.1-28).

The staff has independently calculated the ad valorem tax revenue based on (1) the value of the BFS property, (2) the fact that the assessed value is limited to a maximum of 35% of its actual value, and (3) escalation of the tax rate used by the applicant (ER, Table 8.1-28). The staff believes that the applicant's estimates are reasonable (ER, Sec. 8.1.2.5). However, both the applicant and staff recognize that millage rates could be decreased to reduce local property tax rates while maintaining or even increasing tax revenues. Even so, there are limits to the reduction; for example, four mills must be collected and apportioned to all school districts in the county on the basis of legal average attendance,[25] while the local school district must levy at least five mills.[25] Furthermore, the local school district is required to collect 35 mills for the school general fund and five mills for the school building fund in order to obtain school aid from the State.

The BFS is entirely within Inola School District I-5. The 1975-1976 ad valorem tax levies for the district and Rogers County[26] are shown in Table 4.6. The last column of this table shows the expected tax revenues for each taxing division per year during operation of the plant. About 76% of the money will go to the school district under present law.

Table 4.6. 1975-1976 Ad Valorem Tax Levies for Inola School District and Rogers County

| Taxing Division | Dollars Per $1000 Assessed Value | Percent of Total | Income Per Year to Taxing Body from BFS During Operation (thousands of dollars)[a] |
|---|---|---|---|
| Rogers County | | | |
| General | 10.00 | 14.76 | 4,120 |
| Schoolwide | 4.00 | 5.90 | 1,647 |
| Health | 1.50 | 2.22 | 620 |
| Sinking | 0.72 | 1.06 | 296 |
| TOTAL | 16.22 | 23.94 | 6,682 |
| School District | | | |
| I-5 General | 35.00 | 51.67 | 14,422 |
| I-5 Building | 5.00 | 7.38 | 2,060 |
| I-5 Sinking | 7.60 | 11.22 | 3,132 |
| Vocational technology | 3.90 | 5.76 | 1,608 |
| TOTAL | 51.50 | 76.03 | 21,221 |
| Total County and School District | 67.74 | 99.97 | 27,903 |

[a]Total does not add due to rounding off.

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The applicant states that sales taxes on regional expenditures for construction, equipment, and materials will amount to $2,150,000 (ER, Sec. 8.1.4.5.2) and that BFS will generate direct and induced increases in Federal and State income tax (ER, Sec. 8.1.4.5.3). The staff concurs, but insufficient information is available to calculate the probable tax increases in dollars.

In summary, the taxes paid by the applicant will be a positive impact to the community.

In view of the impacts that may occur in the neighboring communities because of construction of the BFS, the staff believes that it would be desirable for the applicant to establish a set of socioeconomic impact mitigation programs in coordination with local governments and planning agencies. These programs would address such topics as the influx of workers (relocators), housing, education, outdoor recreation, and transportation. Detailed time phasing of various arrangements and aid programs should be considered, using conservative assumptions for predicting the spatial distribution pattern of movers, particularly in the small communities close to the site.

## 4.5 MEASURES AND CONTROLS TO LIMIT ADVERSE EFFECTS DURING AND FROM CONSTRUCTION

### 4.5.1 Applicant's Commitments

The applicant has committed to, and will be required to implement, the following measures to limit adverse effects during construction of the BFS.

#### 4.5.1.1 Terrestrial

1. All abandoned onsite gas or oil wells will be inspected and some may require plugging with grout before operation of Unit 1 (ER, p. 4.1-1).

2. Brush and limbs from site clearing will be disposed of by chipping, burning, or mulching (ER, p. 4.1-3).

3. The fills at the central station complex area will be graded to gentle slopes so as to blend with surrounding terrain and reduce erosion (ER, p. 4.1-3).

4. Topsoil will be segregated and stored at the location shown (ER, Fig. 4.1-5) for subsequent use in revegetating disturbed areas (ER, p. 4.1-3).

5. Corrugated metal, concrete pipe, or reinforced concrete box culverts will be installed at locations where onsite access roads cross existing drainageways (ER, p. 4.1-4).

6. As construction progresses, those temporary buildings and other structures no longer needed will be removed as soon as practicable and the site revegetated as described in the ER, Section 4.5.1.5 (ER, p. 4.1-5).

7. Gentle slopes will be established to provide gradation from spoil-disposal areas to existing terrain and minimize erosion problems (ER, p. 4.1-6).

8. Segregated topsoil will be placed over the spoil banks to aid in revegetation (ER, p. 4.1-6).

9. To reduce erosion resulting from disturbance of the Verdigris River banks by construction of the barge slip, Bermuda grass seed will be planted in early spring at a rate of about five pounds per acre to promote rapid stabilization. Where faster stabilization is required, and at other times of the year, bank soil will be sprigged with Bermuda grass and subsequently rolled or otherwise compacted (ER, p. 4.1-8).

10. Approximately 100 acres of the area directly disturbed by construction of the central complex will be revegetated to a tall grass community according to procedures described (ER, p. 4.1-15).

11. In areas where the terrain is rugged, existing field roads will be used for access to the transmission line right-of-way. This will be done only with prior agreement with the landowner and to reduce possible crop and farmland damage (ER, p. 4.2-2).

12. New right-of-way access roads will be routed to follow present land contours and minimize clearing and possible field damage (ER, p. 4.2-2).

13. Waterways will be maintained for proper drainage, and culverts or other crossing devices will be used to span ditches where land damage would result from erosion (ER, p. 4.2-2).

14. After transmission line construction is completed, access roads will be graded to match natural contours; culverts and other crossing devices removed; ruts filled; and roadways seeded (if necessary) to restore the terrain to its natural condition. Seeding mixes will be used in accordance with the County Conservation Agent's recommendations (ER, p. 4.2-3).

15. To minimize the visual and environmental impact on land and wildlife, right-of-way clearing will be performed on a selective clearing basis (ER, p. 4.2-3).

16. Precautions will be taken to avoid disturbing ground cover along the right-of-way and particularly at stream crossings (ER, p. 4.2-3).

17. Permits will be obtained and all timber cut along the right-of-way will be disposed of through controlled burning where local, regional, or state regulations allow (ER, p. 4.2-3).

18. Where burning is not permitted and disposal is required, all logs will be moved to suitable right-of-way locations to aid in erosion control and all remaining cuttings will be chipped and spread uniformly over the right-of-way. Sheardozing will not be permitted, and materials will not be left nor burned at stream and roadway crossings (ER, p. 4.2-4).

19. Trees or other vegetation will not be chemically treated during clearing or construction of the transmission line (ER, p. 4.2-4).

20. In cultivated areas along the right-of-way, materials detrimental to farming operations, such as rock, will be removed to areas designated by landowners to assist in erosion control (ER, p. 4.2-4).

21. Excess construction materials will be removed from the right-of-way and construction sites cleaned up as soon as each phase of work is completed. Upon completion of construction, damaged areas will be repaired by restoring original contours, filling ruts, reseeding, and mulching, as required (ER, p. 4.2-5).

22. During construction of the transmission lines, every effort will be made to minimize crop damage and losses to productive areas. Movement along the right-of-way will be limited to one established path, and structure site working areas will be kept as small as possible. Upon completion of construction, all equipment and remaining construction materials will be removed and any ruts or other surface damage will be repaired in order to return the land to production as soon as possible (ER, p. 4.2-5).

23. Routes selected for moving vehicles and equipment will avoid damage to stream banks (ER, p. 4.2-9).

24. Structures and towers will be located far enough away from streams so that erosion and destruction of natural growth do not occur along their banks (ER, p. 4.2-9).

4.5.1.2 Aquatic

1. A sheetpile protection wall will be constructed at the intake to provide bank stabilization (ER, p. 4.1-7).

2. A temporary sheetpile cofferdam, with wells or a well-point system, will be used for dewatering during intake construction (ER, p. 4.1-7).

3. Dredged or excavated materials will not be intentionally placed in the river (ER, p. 4.1-19).

4. The intake and related structures will be located on the bank to provide streamline flow without obstructing existing flow or navigation (ER, p. 4.1-7).

5. Spoil from underwater excavation of medium-textured sediments at the barge slip area will be immediately moved onto the designated spoil-deposit area to prevent excessive siltation (ER, p. 4.1-8).

6. Bermuda grass plantings will be performed to help minimize undercutting and eroding of unstabilized banks of the barge slip (ER, p. 4.1-8).

7. Rip-rap will be used at the wastewater outfall structure to stabilize adjacent shoreline to prevent sloughing of bank material (ER, p. 4.1-7).

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8. A temporary cofferdam will be installed at the wastewater outfall structure to reduce erosion (ER, p. 4.5-9).

9. Erosion protection will be provided on the slopes of the discharge canal leading from the wastewater holding pond to the outfall structure (ER, p. 4.5-3).

10. Any clearing of vegetation on the banks of the Verdigris River, Pea and Inola Creeks will be performed so as to leave root structures undisturbed in an attempt to maintain bank stability (ER, p. 4.5-1).

11. Terraces, intercept ditches, and/or other control devices will be built where necessary along the main site drainageways and along the Verdigris River banks to help prevent siltation and erosion (ER, p. 4.5-2).

12. All effluent from the wastewater outfall structure, other than that from untreated overflow, will meet water quality limitations (ER, p. 4.5-2).

13. No creek crossings for the railroad spur or access road will be constructed during spring or early summer to minimize effects on fish moving to upstream spawning locations (ER, p. 4.1-21).

14. Creek crossings will be constructed during low flow so that impacts will be confined to the immediate construction area (ER, p. 4.1-21).

15. Railroad spur trestles will be constructed during dry weather (ER, p. 4.5-10).

16. Permanent store rip-rap will be used for stream-bank stabilization adjacent to timber pile trestles (ER, p. 4.5-10), and creek crossings will be designed to avoid restrictive streamflow (ER, p. 4.1-9).

### 4.5.2 Staff Evaluation

Based on a review of the anticipated construction activities and the expected environmental effects therefrom, the staff concludes that the measures and controls committed to by the applicant, as summarized in Section 4.5.1 above, are adequate to ensure that adverse environmental effects will be mitigated at the minimum practicable level, when supplemented by the following identified requirements.

#### 4.5.2.1 Terrestrial

1. Drainage grading at the central plant facilities site must be completed sufficiently to establish the proposed drainage patterns (ER, Fig. 4.1-3) prior to any site excavation and grading, and must maintain the established drainage pattern of the duration of the construction phase (Sec. 4.1.1.1). For embankments which parallel drainage structures, the final slope of the embankment cannot exceed 3 to 1.

2. If dewatering wells are necessary, the applicant must submit, for staff approval, a monitoring program to detect adverse impacts on groundwater availability (Sec. 4.1.1.1).

3. Inspection of the draw which will carry surface runoff from the construction of the central plant facilities to the wastewater holding pond will be required annually until the construction of the plant is completed to monitor for gully erosion; appropriate mitigating measures, such as rip-rapping or revegetation, shall be applied in a timely fashion to control any erosion detected. This inspection, and mitigating measures, are to be accomplished prior to the estimated normal arrival of spring runoff (Sec. 4.1.1.1).

4. Appropriate preventive measures must be taken to insure that no oil will leak into the barge slip spoils storage area from the wells in the SE 1/4, NW 1/4, and NW 1/4 of Section 13 T19N, R16E. Such measures must be taken prior to the disposal of any spoils. The plans for such measures must be submitted for staff approval prior to initiation of construction (Sec. 4.1.2.1).

5. If new ROW alignments are chosen that differ by more than one-half mile from the reference alignments proposed by the applicant, the applicant will be required to submit appropriate additional information for review and approval by the staff prior to the initiation of construction in the new ROW (Sec. 4.1.3).

6. A construction foreman specifically trained to recognize and protect ecologically sensitive features shall be present and shall supervise all construction on, or adjacent to, riparian habitat, and within 100 feet of the banks of all stream crossings or tributaries. The qualifications of this foreman are to be evaluated and passed upon by a supervisory representative of a governmental agency with recognized expertise in the field of ecology, such as the State of Oklahoma Department of Wildlife Conservation or any other agency acceptable to the staff. In lieu of this, the applicant may secure the services of a similarly qualified biologist who is to be present and to advise the construction foreman at the above areas. In either case, personal inspection of completed areas will be done by a qualified individual. In addition, the transmission line routings in ROW Sections XId, XIe, XIIa and XIIb must be inspected by a qualified biologist to determine if unique mesic habitats are present (Sec. 3.7.3). In the case that such unique habitats are found, the applicant will be required to either span them, avoid them by changing the ROW alignments, or to submit for staff approval, prior to construction, a program to mitigate the potential adverse effects (Sec. 4.1.3).

7. After the tower base locations are staked, the transmission line routings along the entire proposed transmission system must be inspected by an archeologist to verify that no archeological or historical sites will be disturbed. If such sites are found, the NRC must be notified so that appropriate procedures called for by 36 CFR 800 may be carried out (Sec. 4.1.1.4). As an alternative, the location of the tower bases can be offset to avoid damage or disturbance to the archeological resources (Sec. 4.1.3).

4.5.2.2 Aquatic

1. Construction crossings of biologically productive waterways shall be carried out during dry seasons and not during fish spawning seasons or periods of high water or rain (Sec. 4.3.2.4).

2. One-hundred-foot-wide vegetation buffer zones shall be maintained on each side of waterways crossed (Sec. 4.3.2.4).

3. The applicant shall use conservative dredging procedures to minimize siltation during construction of the wastewater outfall structure: e.g., dredged material shall be immediately moved to a designated spoil-deposit area and dredged materials will not be intentionally placed in the river (Sec. 4.3.2.2).

4. Runoff from the spoils-deposit area shall be monitored to ensure that suspended solids limitations are met (Sec. 4.3.2.2).

5. Dredged materials from construction of the wastewater outfall structure shall be disposed of so that they cannot enter the Verdigris River (Sec. 4.3.2.2).

6. Means to prevent discharge of grease, oil, and/or floating solids (such as a skimmer) shall be provided at the discharge structure (Sec. 4.3.2.2).

7. If growth retardants, biocides, insecticide sprays, or any other such chemicals are intended to be used at railroad and access road crossings, a full description of their intended use must be submitted to the staff for review and approval prior to initiation of construction. In no case shall such chemicals be applied within 200 feet of water bodies (Sec. 4.3.2.4).

8. The applicant shall ensure that no vegetation cleared during construction enters any creek or other water body along the transmission right-of-way (Sec. 4.3.2.4).

9. Effective measures must be taken by the applicant to control dust levels, especially near areas of creek crossings (e.g., by use of water, crushed rock surfacing, calcium chloride, and cover-crop planting) (Sec. 4.3.2.4).

10. The applicant shall line the waste water holding pond with a layer of low-permeability soils (Sec. 4.1.1.3).

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# 5. ENVIRONMENTAL IMPACTS OF PLANT OPERATION

## 5.1 LAND USE

The primary impact on land use will be the loss of approximately 2120 acres of grasslands and woodlots that are presently grazed by cattle. The applicant indicated that potential forage productivity is one animal unit per six acres in dry years and is 37.5% higher in wet years (ER, Supplement 0, Answer 2.6). Therefore, the forage productivity loss due to the operation of BFS ranges from 355 to 485 animal units per year. Gradually over the life of the plant, these productivity figures will change. Woodlot forage productivity will decrease with succession, while grassland forage productivity increases (see Sec. 5.6.1). Neither the rates nor magnitudes of these changes can be predicted with any certainty.

One producing oil well and two producing gas wells will be shut down and sealed for the life of the plant to prevent possible leakage with attendant pollution. Production losses will be approximately 180 barrels of oil and 55,000 mcf of gas per year (ER, Supp. 0, Answer 10.7) for the lifetime of the station.

Ten single-family residences will be abandoned during the construction and operation of BFS. The residents of these will have to relocate.

## 5.2 WATER USE

Cooling water for the BFS heat dissipation system will be drawn from the navigation pool behind Newt Graham Lock and Dam on the Verdigris River. Maximum makeup water requirements at 100% load factor will be about 40 mgd (62 cfs). Approximately 4 mgd (6 cfs) will be returned to the river as cooling tower blowdown, and the rest, 36 mgd (56 cfs), will be lost to the atmosphere as vapor or drift. This consumptive use is greater than the minimum instantaneous recorded flow (about 40 cfs) that has occurred since operation of the navigation system began and is about 10% of the median flow (2000 cfs) in this stretch of the river. However, streamflow at the site will be augmented in the future by releases from Oologah Reservoir for use as cooling water makeup for the plant and by releases made to maintain navigation pools as navigation use increases. The impacts on streamflow as a consequence of station operation will thus be minimal in relation to the normal water regulation required for the navigation system. A discussion of the use of Oologah Reservoir to augment and maintain water flow in the Verdigris River is discussed in Section 2.5.11.

Groundwater will not be utilized during operation of the station, and therefore no impacts on use of groundwater are expected.

## 5.3 HEAT DISSIPATION SYSTEM

### 5.3.1 Intake

Makeup water for BFS operation (average of 50.2 cfs, or 22,600 gpm) will be withdrawn from the Verdigris River through an intake structure on the eastern bank of the river. Details of this intake system are given in Section 3.4.4. The potential impacts of water withdrawal upon other uses of the Verdigris and upon the river's biota are evaluated in Sections 5.2 and 5.6.2, respectively.

### 5.3.2 Discharge

Blowdown from the cooling towers will be directed to a holding pond. This pond initially will have a surface area of 11 acres (ER, Supp. 0, Question 3.9) but can be expanded to 37 acres (ER, Supp. 0, Questions 3.2 and 3.8) as required throughout the station life to offset the volume decrease caused by siltation. The relationship between pond surface elevation, surface area, and

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pond volume is shown in the ER, Figure 10.3-1. For an 11-acre pond, the holdup time will average between two and four days and will be primarily a function of the cooling tower blowdown rate. Considerable cooling of the heated effluent will occur during passage through the holding pond. The pond effluent will be released to the Verdigris River as a surface discharge.

#### 5.3.2.1 State Thermal Water Quality Standards

The Oklahoma water quality standards require that:

1. The maximum temperature rise at any time outside the mixing zone must not exceed natural temperatures by more than 5°F;
2. The maximum temperature allowed outside the mixing zone is 90°F;
3. The mixing zone is an area no larger than one-fourth the cross-sectional area of the stream or no more than one-fourth the volume of flow, whichever is more restrictive; and
4. Normal daily and seasonal temperature fluctuations that existed before the addition of heat due to other than natural causes shall be maintained.

#### 5.3.2.2 Applicant's Thermal Analysis

The results of the applicant's thermal analysis are given in Table 5.1, which lists the cooling tower blowdown temperatures and holding pond discharge temperatures for the following conditions:

1. Monthly averages, based upon 80% station load, monthly average meteorology and river temperature, median river flow (2000 cfs);
2. Expected annual maximum, based upon 100% station load, average January meteorology and river temperature, median river flow; and
3. Realistic worst case, based upon 100% station load, average January meteorology and river temperature, 30-day average extreme low flow (379 cfs).

Table 5.1. Station Effluent Characteristics and River Parameters--Applicant's Results

| Month | Cooling Tower Blowdown Temperature, °F | Holdup Pond Discharge Temperature, °F | Verdigris River Temperature, °F | Discharge Rate, gpm | Area Enclosed By Isotherms, $ft^2$ | | |
|---|---|---|---|---|---|---|---|
| | | | | | 5° | 3° | 2° |
| Jan | 66 | 44 | 38 | 2340 | 5[a] | 30[a] | 80[a] |
| Feb | 68 | 47 | 42 | 2460 | | | |
| Mar | 70 | 54 | 49 | 2600 | | | |
| Apr | 75 | 64 | 61 | 2890 | 0[b] | 0[b] | 5[b] |
| May | 80 | 72 | 70 | 3050 | | | |
| Jun | 84 | 80 | 80 | 3080 | | | |
| Jul | 86 | 83 | 83 | 3050 | | | |
| Aug | 85 | 83 | 83 | 3030 | | | |
| Sep | 82 | 77 | 77 | 3050 | | | |
| Oct | 77 | 68 | 66 | 2820 | | | |
| Nov | 71 | 55 | 51 | 2570 | | | |
| Dec | 68 | 47 | 42 | 2460 | | | |
| Expected annual maximum | 69 | 48 | 38 | 2860 | 30 | 100 | 300 |
| Realistic worst case | 69 | 48 | 38 | 3150 | 40 | 100 | 300 |

[a]Worst monthly average.

[b]Actually the average for April and October.

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The applicant made no calculations for cases of extreme meteorological conditions or extreme river temperatures. The cooling tower blowdown temperatures correspond to the mean wet-bulb temperature for each month. The applicant calculated the holding pond effluent temperatures using nomograms found in the Chemical Engineer's Handbook.[1]

Numerous analytical models have been developed to describe the physical characteristics of surface discharges. Many of these models have been reviewed by Policastro and Tokar.[2] As a result of the dearth of reliable field data, none of these models has been adequately tested. The model chosen by the applicant was developed by Shirazi and Davis;[3] it evolved from an effort to modify the Prych model (see Ref. 2) to make it better agree with existing data.

Figure 5.1 shows calculated isotherms for the four cases, as described in the text and in Table 5.1. The table also gives the size of areas enclosed by various isotherms.

5.3.2.3 Staff's Thermal Analysis

The staff has calculated the cooling tower blowdown temperatures, holding pond discharge temperatures, and resulting thermal plumes under average and under adverse meteorological and hydrological conditions. Table 5.2 contains the data used in the calculations; Table 5.3 lists the results of the staff's calculations.

The calculated average cooling tower blowdown temperatures are based on average wet-bulb temperatures and 80% station load. The maximum calculated blowdown temperatures are based on wet-bulb temperatures which are exceeded only 2% of the time each month at 100% station load.

Holding Pond Analysis

There are two extreme classifications of cooling ponds. In a completely mixed pond, the flow between the intake and discharge, combined with wind effects, tends to maintain the pond at nearly uniform temperature throughout. In a flow-through (plug-flow) pond, the temperature decreases continuously along the flow path from intake to discharge. Any given pond will fall somewhere between these two extremes.

The principal mechanisms by which heat is exchanged between the water and the atmosphere are:

- Incoming short-wave solar radiation,
- Incoming long-wave atmospheric radiation,
- Outgoing long-wave back radiation,
- Reflected solar and atmospheric radiation,
- Heat loss due to evaporation, and
- Heat loss or gain by conduction.

The equilibrium temperature, E, is defined as the temperature a body of water would eventually reach when cooled or heated naturally under constant meteorological conditions. A body of water at a temperature different from E will tend to approach E asymptotically. The equilibrium temperature is not a constant, but varies throughout the day and throughout the year as the meteorological variables change.

Although the temperature of a natural body of water approaches the equilibrium temperature, it lags behind the short-term changes. It is usually close to the equilibrium temperature during the summer and winter, lower during the spring, and higher during the fall.

The simplified model for predicting temperatures in a cooling pond assumes that the net rate of heat exchange, $\Delta H$, across the surface of the pond is proportional to the difference between the surface temperature of the lake, $T_s$, and the equilibrium temperature, E.

$$\Delta H = -K(T_S - E) \qquad (1)$$

The proportionality factor, K, is a complicated function of the meteorological variables, as is E. When appropriate averages are used (e.g., monthly averages), the temperature $T_s$ may be calculated within about ± 5°F.

The temperature $T_F$ at the end of the pond can be calculated from the following equations:

$$\frac{T_F - E}{T_o - E} = e^{-r} \qquad \text{Plug Flow Pond} \qquad (2)$$

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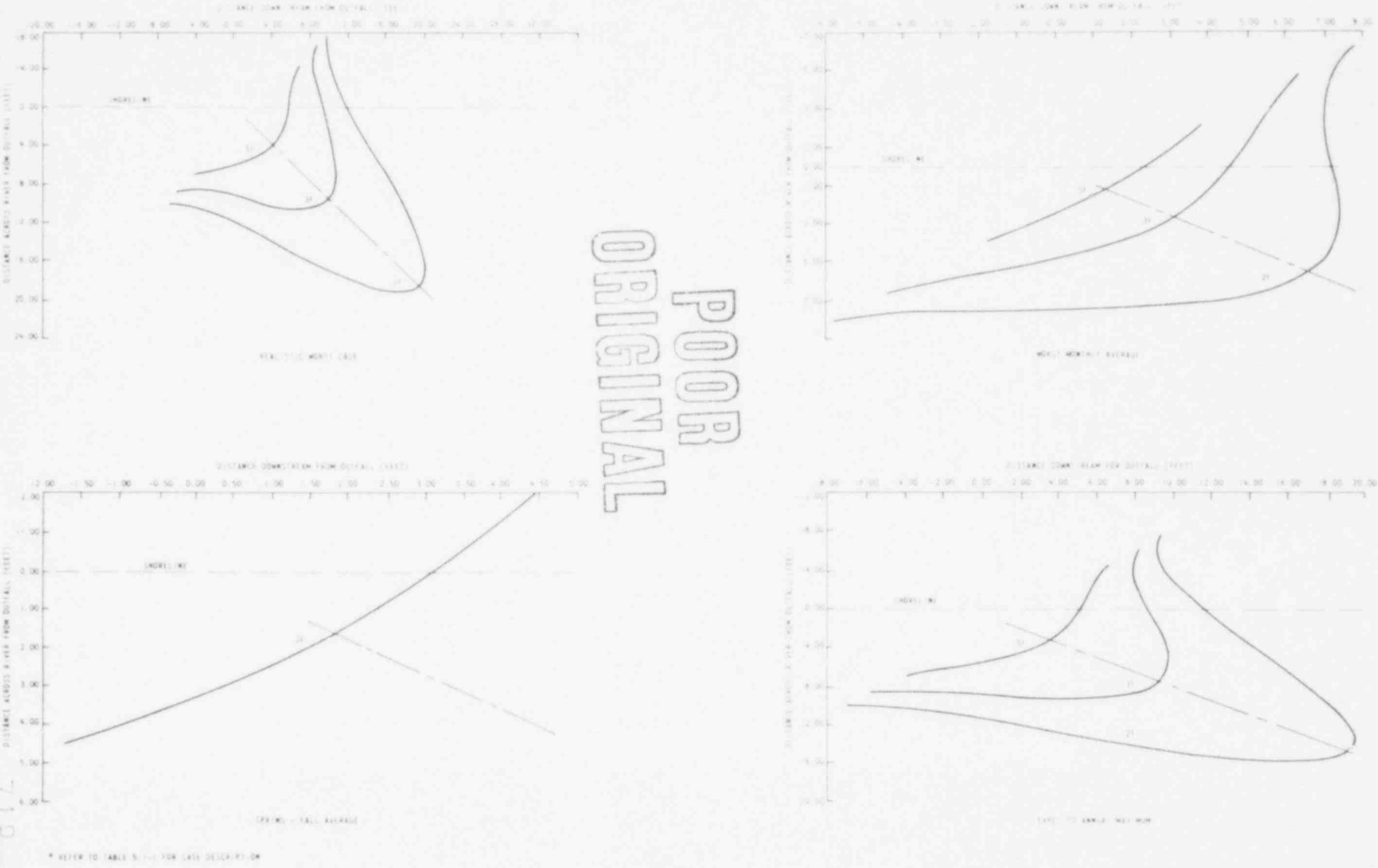

Fig. 5.1. Applicant's Predicted Surface Isotherms. From ER, Fig. 5.1-1.

Table 5.2. Meteorological and Hydrological Data Used by the Staff

| Month | Temperature, °F | | Holding Pond Discharge Flow, cfs, | | Verdigris River Temperature, °F | | |
|---|---|---|---|---|---|---|---|
| | Wet-Bulb Ave | Max[a] | Ave[b] | Max[c] | Min[d] | Ave[e] | Max[d] |
| Jan | 31 | 58 | 5.21 | 6.51 | 32 | 38 | 59 |
| Feb | 35.5 | 58 | 5.48 | 6.85 | 34 | 42 | 59 |
| Mar | 41 | 62.5 | 5.79 | 7.24 | 39 | 49 | 63 |
| Apr | 52 | 69 | 6.44 | 8.05 | 46 | 61 | 83 |
| May | 63 | 74.5 | 6.80 | 8.50 | 52 | 70 | 81 |
| Jun | 69.5 | 77.5 | 6.86 | 8.58 | 64 | 80 | 88 |
| Jul | 72 | 78 | 6.79 | 8.49 | 72 | 83 | 97 |
| Aug | 70.5 | 78 | 6.75 | 8.44 | 74 | 83 | 94 |
| Sep | 65 | 75.5 | 6.79 | 8.49 | 60 | 77 | 86 |
| Oct | 54 | 70 | 6.28 | 7.85 | 54 | 66 | 78 |
| Nov | 42 | 64 | 5.73 | 7.16 | 42 | 51 | 66 |
| Dec | 35.5 | 56 | 5.48 | 6.85 | 33 | 42 | 54 |

[a]Value exceeded only 2% of the time for each month for the period of record (March 1953-February 1963) at Tulsa, Oklahoma.

[b]Data for 80% plant load factor (ER, p. 3.4-10).

[c]Data for 100% plant load factor, obtained by dividing average flows by 0.8.

[d]Data from "Water Resources Data for Oklahoma," Part 2, USGS, for water years 1964-65, 1968-74.

[e]Data from 1947-73 (ER, p. 2.4-53).

Table 5.3. Results of Staff's Calculations

| Month | Cooling Tower Blowdown Temperature, °F | | Holding Pond Discharge Temperature, °F | | | |
|---|---|---|---|---|---|---|
| | Ave | Max | Ave | Max | $\Delta T_n$,[a] °F | $\Delta T_e$,[b] °F |
| Jan | 70.5 | 81.5 | 52.1 | 62.9 | 14.1 | 30.9 |
| Feb | 72 | 81.5 | 55.3 | 65.9 | 13.3 | 31.9 |
| Mar | 74 | 83 | 59.9 | 69.8 | 10.9 | 30.8 |
| Apr | 78.5 | 86 | 68.7 | 76.8 | 7.7 | 30.8 |
| May | 83.5 | 89.5 | 76.2 | 83.0 | 6.2 | 31.0 |
| Jun | 86.5 | 91.5 | 82.9 | 88.9 | 2.9 | 24.9 |
| Jul | 88.5 | 92 | 86.9 | 92.0 | 3.9 | 20.0 |
| Aug | 87 | 92 | 85.7 | 90.8 | 2.7 | 16.8 |
| Sep | 84.5 | 90 | 79.8 | 88.4 | 2.8 | 28.4 |
| Oct | 79.5 | 87 | 69.6 | 77.6 | 3.6 | 23.6 |
| Nov | 74.5 | 84 | 59.5 | 70.3 | 8.5 | 28.3 |
| Dec | 72 | 80.5 | 55.0 | 63.5 | 13.0 | 30.5 |

[a]Average holding pond temperature minus average river temperature.

[b]Maximum holding pond temperature minus minimum river temperature.

$$\frac{T_F - E}{T_o - E} = \frac{1}{1 + r} \qquad \text{Completely Mixed Pond} \qquad (3)$$

$$r = \frac{KA}{\rho C_p Q} \qquad (4)$$

Where:
$A$ = surface area of the lake ($ft^2$)
$\rho$ = density of water (62.4 $lb/ft^3$)
$C_p$ = specific heat of water (1 Btu/lb·°F)
$Q$ = discharge flow rate ($ft^3$/day)
$T_o$ = original temperature (°F).

Thackston and Parker have calculated the equilibrium temperatures and heat exchange coefficients for 88 locations throughout the country.[4] Figure 5.2 is a plot of these parameters for Oklahoma City for each month of the year. The solid curve represents the values that correspond to average meteorological conditions. The dashed curve corresponds to extreme meteorological conditions, and results from assuming that all meteorological variables are at the values that are exceeded only once in ten years. The probability that all these variables are at the extremes simultaneously is small. The uncertainty in E is typically ± 5°F; the uncertainty in K is approximately ± 40%. One of the largest contributors to the uncertainty is the specific form chosen for the wind formula for determining the heat loss due to evaporation. Thackston and Parker have employed a very conservative formula so that it is not unreasonable to expect that there will be more cooling than predicted using their values.

The holding pond discharge temperatures given by the applicant can be reproduced if one assumes that the holding pond will be a perfect plug-flow pond (Eq. 2). However, the staff has made the assumption that this pond is completely mixed (Eq. 3), thus yielding conservative results. In the staff's calculations, the discharge temperatures can be as much as 5°F warmer than those derived by the applicant. The maximum holding pond temperatures are calculated assuming adverse meteorological conditions (extreme values of K and E from Fig. 5.2) and maximum discharge flows (listed in Table 5.2).

Temperature differences between holding pond discharge and the ambient river are given for two possibilities. $\Delta T_n$ is the difference between average holding pond discharge and average river temperature. $\Delta T_e$ represents an extreme case of maximum holding pond discharge temperature and minimum river temperature. Since the probability of these two occurring simultaneously is extremely small, the probability of observing such large temperature differences is small. However, the staff's calculations represent a very conservative analysis.

Thermal Plume Analysis

The staff has used, as did the applicant, the Shirazi-Davis model to determine the size and orientation of the thermal plume in the Verdigris River. Figure 5.3 shows the thermal plume for March under the extreme conditions mentioned above, and the conservative assumption of 0.045 fps ambient water velocity. The area enclosed by 5°F and 3°F excess isotherms are 580 square feet and 2000 square feet, respectively. The 5°F excess isotherm extends about 30 feet downstream from the point of discharge and about 24 feet into the river. The river width at the location of the discharge is 268 feet. Thus, even in this extreme case, Oklahoma State standards for thermal discharges will always be met (affected area less than one-fourth the width of the river).

Two interesting possibilities present themselves; each can be expected to occur during the life of the plant:

- Case 1--In the event the river temperature reaches 96°F and the plant effluent temperature 92°F, the plant effluent will help to reduce the river temperature (at least infinitesimally), and yet the river temperature will naturally remain above 90°F.

- Case 2--If river temperature is 90°F and the heated discharge is 92°F, even though the initial ΔT is only 2°F and will be greatly diluted within a very small area near the outfall, no mixing zone of any size will reduce the temperature to 90°F or below.

The State water quality standards do not address themselves to these possibilities; therefore no definite conclusion as to compliance or violations of the standards can be made. However, it can be stated that under these circumstances, the station will either contribute to reduction of the river temperature or will increase it by at most 2°F at the point of discharge and by an undetectable amount within a few feet from the discharge.

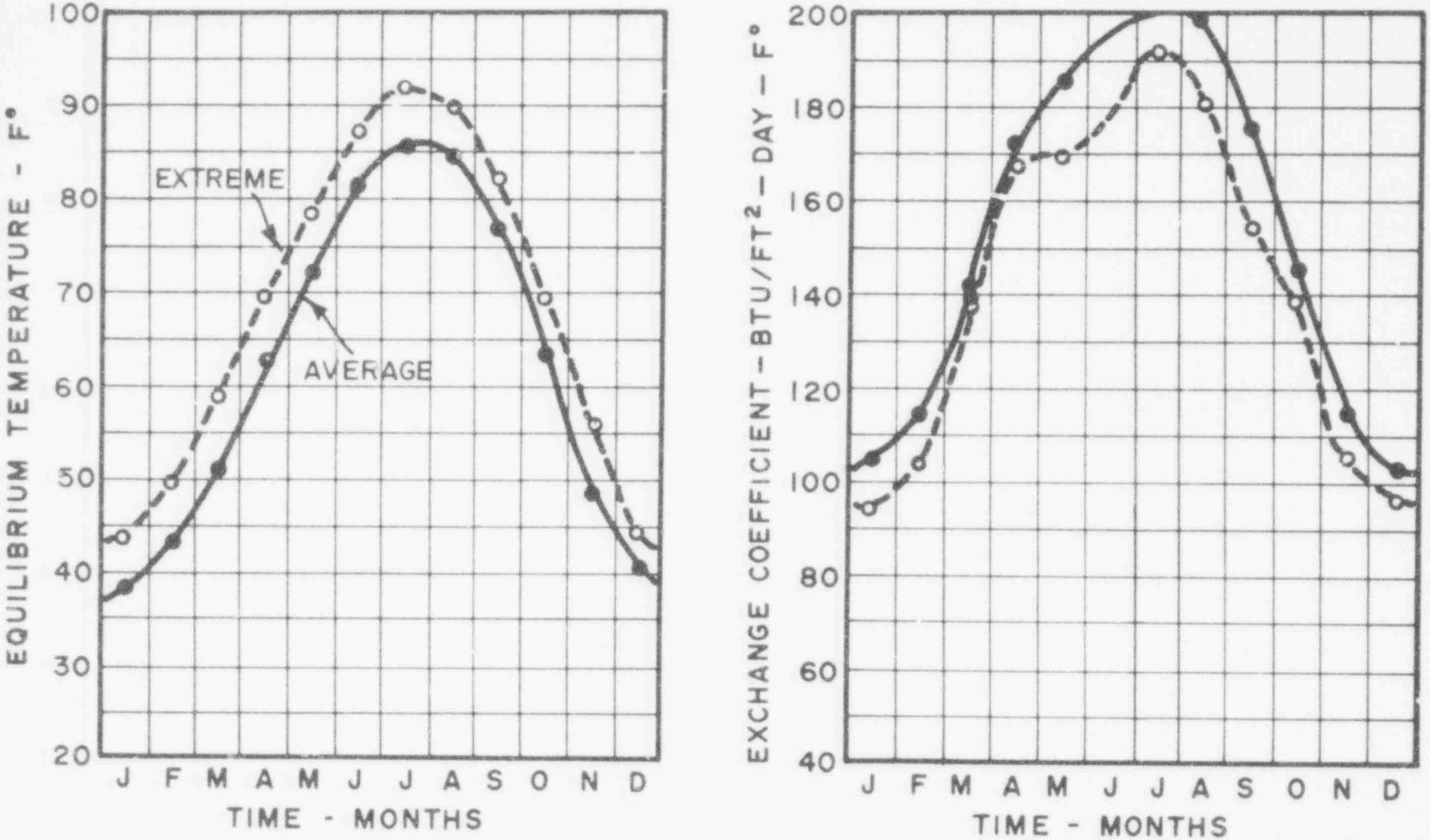


Fig. 5.2. Equilibrium Temperatures and Heat Exchange Coefficient for Oklahoma City. From "Effect of Geographical Location on Cooling Pond Requirements and Performance," Fig. 98, Water Quality Office, U. S. Environmental Protection Agency, March 1971.

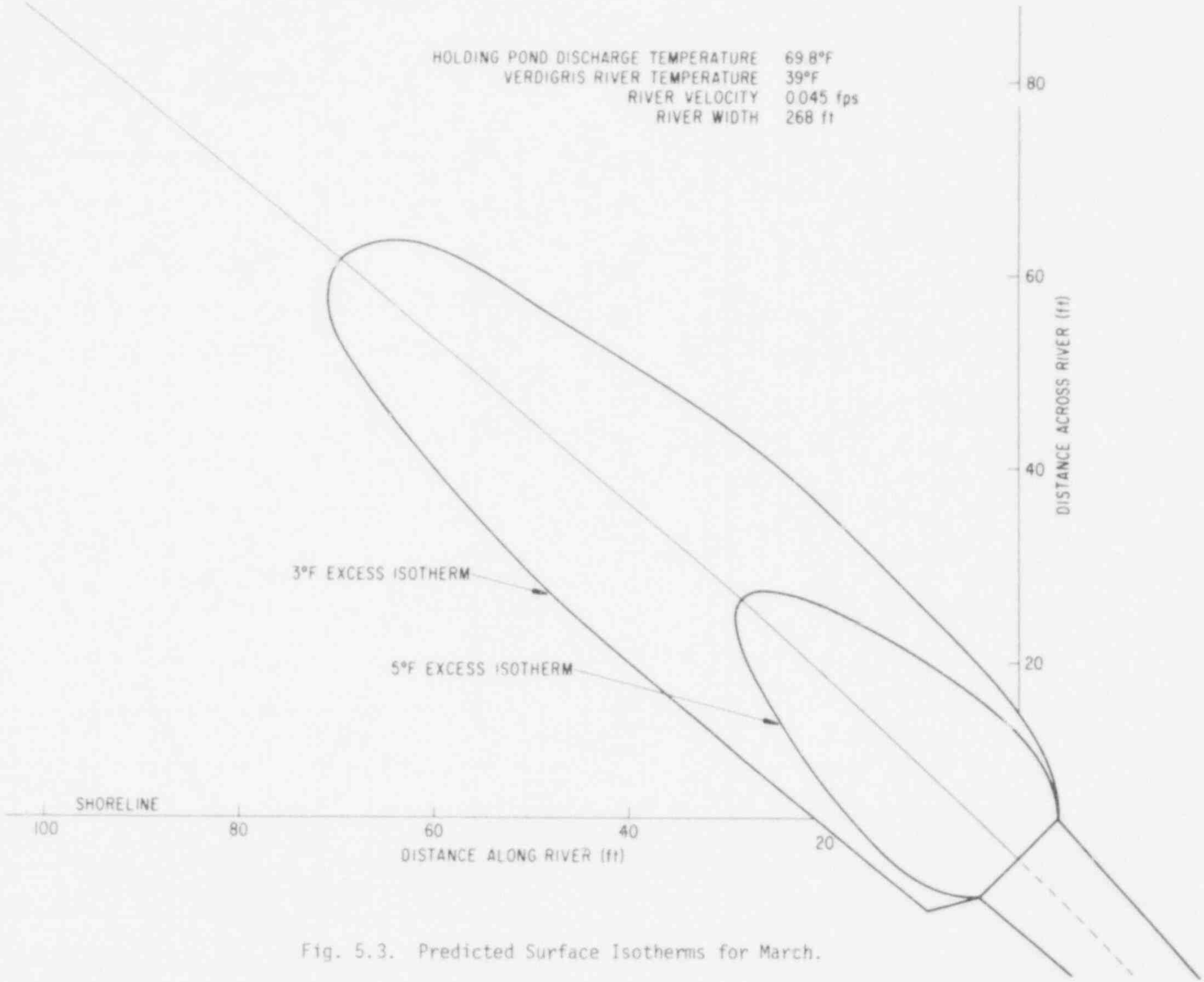


Fig. 5.3. Predicted Surface Isotherms for March.

The staff does not know of any models that take into account the sinking plume phenomenon. This phenomenon occurs when the density of the warm effluent is greater than the ambient river water (water has a maximum density at about 39°F). This would only be expected to occur during the months of December, January, and February, when the ambient river water can be less than 39°F. It is estimated that the area within the 5°F or 3°F excess isotherm could possibly double as it sinks to the bottom.

5.3.2.4 Conclusions

The applicant analyzed the thermal effects of BFS for 80% load factor and 100% load factor. All calculations, including the case labeled "Realistic Worst Case," assumed average meteorological conditions and average river temperatures, and therefore do not represent true extreme possibilities.

The staff has been more conservative in selecting parameters for the calculations. These were:

1. 100% plant load,
2. A wet-bulb temperature exceeded only 2% of the time to determine cooling tower blowdown temperatures,
3. Extreme values of equilibrium temperature and heat exchange coefficient,
4. Assumption of a fully mixed holding pond,
5. Minimum river temperatures, and
6. Low river flow.

The area enclosed by the 5°F excess isotherm for this case is approximately 14 times larger than the applicant's realistic worst case (580 square feet compared with 40 square feet). However, this most conservative plume is extremely small compared with the size of the allowable mixing zone, and the plume under more normal conditions will be much smaller. Except in the case where the ambient river temperature exceeds 90°F, the staff concludes that the proposed design of the surface discharge and its operation will be acceptable in meeting water quality standards relating to temperature.

5.3.3 Heat Transfer

5.3.3.1 General Considerations

Six circular mechanical-draft cooling towers (CMDCT), three for each unit, will be used to discharge more than 99% of the waste heat from the condensers directly to the atmosphere. Each CMDCT will have 13 fans. In addition, two 4-cell mechanical-draft cooling towers (one per unit) of conventional design will be used to cool the essential-service water during the warmer part of the year and to act as the plant's ultimate heat sink (UHS). The CMDCT is a recent design concept; only one such tower is now in operation--a 13-fan unit at the 500-MWe fossil-fueled Jack Watson plant in Mississippi, which began operation in March 1975.[5] Thus, experience with CMDCTs is limited.

In CMDCTs, heat and vapor are transferred from the circulating-water system to the air being pulled through the tower by the fans. On the average, about 75% of the heat removal will be by evaporation, varying from 60% in winter to 90% in summer.

Part of the evaporated water will condense inside the tower. When the effluent leaves the tower, it mixes with cooler, less humid ambient air, and more of the water vapor in the discharge will condense in the form of a visible cloud-like plume. Because of the plume's buoyancy and momentum, it will, under most conditions, continue to rise and carry along evaporated water and a mist of water droplets (called "drift") swept from the circulating water in the fill. The drift will contain whatever soluble and suspended chemicals are present in the circulating water. Because large amounts of heat and water vapor are added to the atmosphere over a small area, local atmospheric changes will occur. These atmospheric modifications can be separated into four general categories: elevated visible plumes, ground-level fogging and icing, drift effects, and cloud and precipitation formation.

The staff's analysis of possible effects of the cooling tower effluents from the BFS site is given below.

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5.3.3.2 Visible Plumes

The length of visible plumes created by CMDCTs will depend upon plant factors (such as plant load) and cooling-tower-design parameters (such as cooling range and approach), as well as upon

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local weather conditions (air temperature, wind speed and direction, saturation deficit, and stability). Because air at low temperature has a small capacity to hold water vapor, visible plumes will be longer and more pronounced in winter.

Under most meteorological conditions, the water droplets in the visible plume will evaporate within a few hundred feet of the towers. Under other conditions (especially periods with low air temperatures, high humidity, perhaps light rain or drizzle, moderate wind speeds, and a stable atmosphere) the visible plume may extend for several miles.[6,7] Hanna and Perry[7] report that plumes from a conventional mechanical-draft cooling tower (MDCT) in Tennessee frequently "formed a stratus deck just below the main stratus deck, and that the man-made cloud could be seen extending tens of kilometers to the horizon. It would be interesting to see if rainfall were increased beneath this cloud." The main impact of the elevated plume, other than its appearance, is the reduction of sunshine reaching the area it shades. The decrease in incoming radiation at ground level is not expected to be significant because of the shifting shadow, the small area affected at any moment, and natural cloudiness (long plumes will usually occur during periods of natural cloud cover). Visible plumes will be more frequent and longer in winter than during the other seasons, and the minimum size and the lowest frequency of long plumes will occur in summer. On the daily cycle, plumes will be longest just before and after sunrise, and shortest in mid-afternoon.

Applicant's Analysis

The applicant has developed and/or used several computer models to estimate the atmospheric effects (such as plume lengths, fogging, icing, and drift) of several types of mechanical-draft cooling towers at BFS; these models are described in the ER, Section 6.1.3 and Supplement 0, and in References 8 and 9. A summary of the output of these models is given in the ER, Sections 5.1.4 and 10.1.4. Ten years of Tulsa meteorological data were used in the cooling tower calculations (ER, Sec. 5.1.4.1 and Supplement 0, Question 5.6).

Two distinctly different cooling tower models were used by the applicant to calculate plume lengths and fogging. In one model, the plume leaves the tower and rises to a final height determined by the momentum and buoyancy of the effluent and by prevailing weather conditions. This model[8] employs the plume rise equations of Briggs,[10] the bent-over plume theory as applied to moist plumes by Hanna,[11] and the standard atmospheric gaussian dispersion equations at the end of the bent-over plume regime.

In the second model, at high wind speeds the plume is drawn into an eddy in the lee of the tower; this process is called aerodynamic downwash and is the primary, if not the only, cause of fogging from MDCTs of conventional (linear) design.[7,12-] The applicant has developed a numerical model to estimate plume lengths and fogging during periods of downwash conditions (ER, Sec. 6.1.3.2.4 and Ref. 4). Due to the improved aerodynamic shape of round cooling towers and the more concentrated plumes,[12] the applicant expects no fogging due to downwash. Downwash conditions are expected for the MDCTs of conventional design (long rows of cells) considered as an alternative cooling system.

The applicant's analysis shows that 90% of the time the plumes will be short (0.8 km or less). Plumes 1.5 km or longer will occur 792 hours per year, or about 9.0% of the time. Long plumes (10 km or longer) will occur 25 hours per year (0.3%). The model predicts that plumes longer than 20 km will not occur. These calculations incorporated the conservative assumptions that (1) both units operate at full capacity at all times, and (2) natural cloud cover is ignored.

Staff Analysis

The staff has concluded that the applicant's model yields reasonable estimates of plume lengths for conditions where aerodynamic downwash does not occur. Limited experience at the operating CMDCT in Mississippi[1] and physical hydraulic model tests[12] indicate that the critical wind speed for the onset of downwash with CMDCTs is much higher than for a conventional MDCT. Hanna[13] studied cooling tower plumes in Tennessee and found that downwash did occur whenever the wind component normal to the long axis of the tower was more than about 7 mph (3 mps) and that downwash occurred 65% of the time. Dickey et al.[5] have published a photograph of the plume from the Jack Watson plant with no downwash at a wind speed of 20 mph (9 mps). This result is in agreement with laboratory modeling experiments.[12] These hydraulic model studies also show that the plumes from multiple towers combine and rise to a higher elevation than those from single tower sites.[12] Thus, the applicant's claim concerning downwash seems reasonable.

Other than the esthetic impact, the staff expects no significant offsite effects from the elevated visible plumes from the station's CMDCTs.

5.3.3.3 Ground-Level Fogging and Icing

There are two mechanisms by which fog could be created downwind of the BFS cooling towers: (1) aerodynamic downwash and (2) downward dispersion of moisture from an elevated plume. Because of the much lower height of release (60 vs. 500 feet), fog from the second process is more likely to occur with MDCTs and CMDCTs than with the much taller natural-draft cooling towers (NDCTs). However, contrary to popular belief, there are no documented cases of fog due to this process from either NDCTs or MDCTs.[9,13-15]

With air temperatures below 32°F, the recondensed water in the visible plume will become supercooled water droplets. As a result of their small size, these droplets will tend to avoid, rather than impact, surfaces such as trees, poles, and wires. The ice that does form on elevated surfaces will be light rime ice of low density and little structural strength. Icing can also result from the freezing of drift droplets after impact.

Applicant's Analysis

The applicant's two fogging models are discussed and referenced in Section 5.3.3.2. The results of the calculations are given in the ER, Section 5.1.4 and Tables 5.1-3 through 5.1-7. Because of the aerodynamic shape and more concentrated plume of the CMDCTs, the applicant does not expect operation of the six round towers to cause any downwash fog. Two meteorological regimes were considered in calculating hours of fog caused by dispersion of moisture from elevated plumes--(1) normal dispersion (when plume rise is not limited by a strong inversion), and (2) plume trapping (when plume rise and dispersion of moisture upwards are restricted by a strong inversion aloft). The model predicts up to 16 hours of fog per year within five kilometers during periods of normal dispersion, and 240 hours per year near the tower (0.1 km) during plume trapping conditions (ER, Table 5.1-3). The expected fog frequencies as functions of distance and direction from the plant are given in Table 5.4. The majority of these tower-induced fogs will increase the density of natural fog.

Table 5.4. Hours of Ground Fog Occurrence due to Round Mechanical-Draft Cooling Towers

| Distance, km | Hours per Year for Given Direction[a] | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | S | SSW | SW | WSW | W | WNW | NW | NNW | N | NNE | NE | ENE | E | ESE | SE | SSE |
| Plume-Trapping | | | | | | | | | | | | | | | | |
| 0 | 25 | 6 | 9 | 8 | 9 | 7 | 7 | 17 | 56 | 8 | 4 | 6 | 14 | 15 | 23 | 23 |
| 1 | 17 | 4 | 6 | 5 | 6 | 5 | 5 | 12 | 39 | 6 | 3 | 4 | 10 | 10 | 16 | 16 |
| 2 | 6 | 2 | 2 | 2 | 2 | 2 | 2 | 4 | 14 | 2 | 1 | 2 | 4 | 4 | 6 | 6 |
| 3 | 5 | 1 | 2 | 1 | 2 | 1 | 1 | 3 | 11 | 2 | 1 | 1 | 3 | 3 | 4 | 4 |
| 5 | 4 | 1 | 1 | 1 | 1 | 1 | 1 | 3 | 9 | 1 | 1 | 1 | 2 | 2 | 4 | 4 |
| 10 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 5 | 1 | 0 | 1 | 1 | 1 | 2 | 2 |
| 25 | 0.5 | 0[a] | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 50 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Normal Dispersion | | | | | | | | | | | | | | | | |
| 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | 2 | 1 | 0 | 0 | 0 | 0 | 1 | 2 | 5 | 2 | 1 | 0 | 0 | 0 | 1 | 1 |
| 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

[a]0 denotes less than 0.5 hour per year.

From ER, Table 5.1-4.

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Up to 14 hours per year of tower-induced ground fog are expected along a 1.5-mile stretch of Highway 33, about three miles north of the plant (ER, Table 5.1-7). The town of Inola is expected to have two hours per year of induced fog. No fog is expected over U. S. Highway 69, which is a north-south road about 11 miles east of the BFS. The applicant expects three hours or

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less of induced fog over the Verdigris River per year; again the effect would occur mostly during periods of dense natural fog. Most of the periods of induced fog will occur with subfreezing temperatures; however, no damaging accumulations of ice are expected on vertical surfaces or on roads. The maximum expected offsite fogging and icing is 16 hours per year north of the site. Because of the low density and fragile nature of rime ice, no damage is expected to crops, trees or structures. The effect of this icing will be negligible, especially when compared with the damage done by the 26 hours per year of freezing rain (which deposits hard, clear ice on all surfaces) that the Tulsa area averages each year.

Staff's Analysis

The staff agrees with the applicant that most of the icing and fogging impacts will occur onsite, and that no significant offsite fogging impacts will be created by the six CMDCTs at BFS. The staff also considers the applicant's model to be conservative in that it overestimates the frequence of offsite fogging. Conservative assumptions used in the calculations include 100% operation of both units at all times, and no periods of natural fog. Also, fog due to the meteorological process the model simulates has never been reported.[8,13-15] Icing conditions due to the plumes should be confined to site, and this ice will do no damage. Icing due to the freezing of drift droplets may cause some dense, clear ice on road and other surfaces near the plant, but not offsite. There are no reports of significant or damaging icing conditions downwind of MDCTs in the open literature; the staff expects none at BFS.

The moisture emitted by the BFS cooling towers will produce local changes in relative humidity at ground level. Two mechanisms, downwash and dispersion from an elevated plume, are available to change humidity. Humidity increases of as much as 50% have been measured in the downwash region downwind of linear MDCT's in Tennessee.[7,13] Due to their shape, downwash conditions will be much less frequent than at locations with linear MDCT's. In any event, the area of humidity increases due to downwash will be limited to onsite areas, as the buoyancy and momentum of the plumes will lift them from the surface.

Small offsite humidity increases may occur due to the downward dispersion of moisture from elevated cooling tower plumes. The exact value of the humidity change at ground level will depend on many factors, such as air temperature, relative and absolute humidity, plume rise, wind speed, stability as well as plant load and cooling tower parameters. No monitor measurements of humidity changes by these mechanisms from MDCT's are available for analysis; a field program to do so is now underway by the University of Michigan at the Palisades Nuclear Plant in Michigan. Humidity changes due to this process will be small (a few percent at most) and will be lost in the natural variability of natural fluctuations of temperature and humidity.

5.3.3.4 Drift

A small fraction, 0.005%, of the cooling water will be carried into the plume and discharged to the atmosphere as drift. These water droplets will contain the same types of solids that are present in the circulating water system, and could cause impacts from wetting, icing, and deposition of salts and chemicals onto the soil, plants, and structures. Under most meteorological conditions, the water in the drift droplets will evaporate, and the salts will remain airborne and be dispersed by wind. Under conditions of high humidity, however, the drops may not evaporate completely before impacting surfaces. Studies at operating mechanical-draft towers indicate that most of the drift that does fall to the ground will do so within 1000 feet (300 m) or so of the towers.[13-17] When the air temperature is below freezing, the drift falling to the ground can cause icing.

Applicant's Analysis

The applicant has developed a computer model to estimate drift deposition rates for BFS (ER, Sec. 6.1.3.2.5, and Ref. 9). The model is based on the work of Hosler et al.,[13] and incorporates ten years of weather data from Tulsa Airport and the gross drift rate (0.005%) and drop-size spectrum supplied by the vendor of the proposed towers. A total dissolved solids (TDS) level of 2248 parts per million and 100% operation of both units were assumed.

The maximum calculated drift deposition rates will occur within 0.2 mile of the tower (that is, onsite) and vary from 15 to 558 pounds per acre per year, as shown in Figure 5.4. The maximum calculated precipitation deposition outside the 0.2-mile radius is 0.01 inch per year.

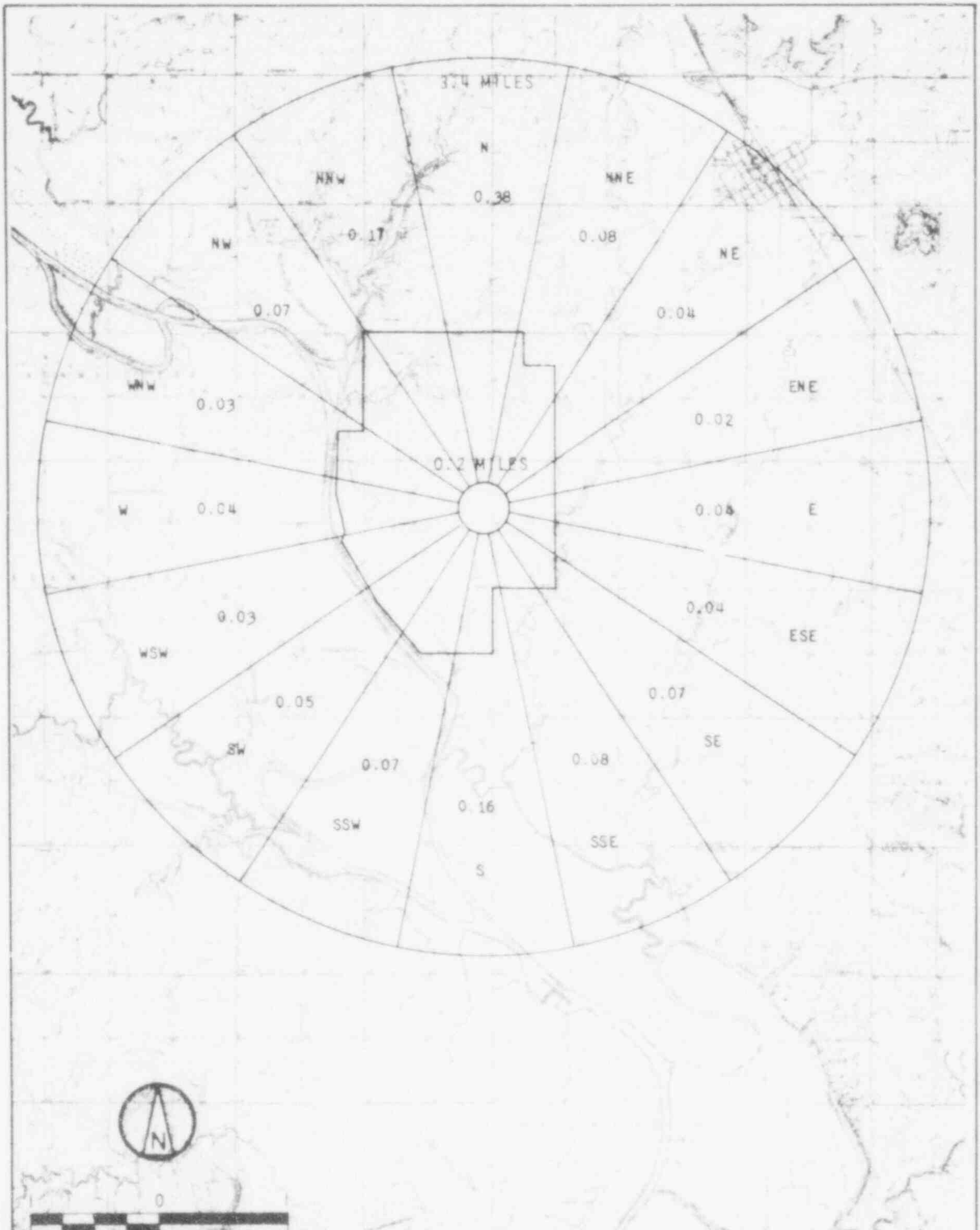


Fig. 5.4. Average Drift Deposition Rate (lb/month-acre) in Each Secto. from Round Mechanical-Draft Cooling Towers. From ER, Fig. 5.1-3.

Staff Analysis

The staff is not able to assess the accuracy or validity of the applicant's drift model because of the complete lack of drift measurements at operating CMDCTs or MDCTs with which to test the model.[19] Experience at operating MDCTs, however, indicates that drift effects are "observed to be insignificant, except in the area within a few hundred meters of the tower."[14] The staff agrees with the applicant's conclusions that almost all of the drift that does return to the ground will do so inside the station boundary, and that because of the small amount of deposition and the low TDS content of the water, there will be no problems with icing or salt deposition, even onsite.

5.3.3.5 Cloud and Precipitation Formation

The visible plume from a cooling tower is a cloud. In addition, clouds are sometimes observed to form in the updraft created by a cooling tower after the initial visible plume has evaporated. Hanna[13] reports that cloud development is initiated by plumes from the Oak Ridge cooling towers 10% of the time. There have been a few reported occurrences of very light snow due to cooling tower plumes, but in all cases the amounts were very small.[20,21] Hanna[13] and others have speculated that local precipitation could be increased by natural rain and snow falling through the plumes, but no data are available with which to appraise this effect. Recent studies indicate that thermal discharges of the magnitude of the BFS do not cause significant changes in local weather conditions (other than the visible tower plumes).[15,22-25]

Cooling-tower plumes do create clouds and slightly alter sunshine in the immediate area; however, there is no evidence that they cause significant changes in local weather conditions. Some meteorologists believe that the waste heat from a group of cooling towers could, given proper atmospheric conditions, trigger a violent thunderstorm that could develop into a tornado.[26] This possibility has been discussed at length[26] but, unfortunately, the state-of-the-art in atmospheric modeling is such that a definitive conclusion is not now possible. The report does conclude that clusters of mechanical- and natural-draft wet cooling towers with energy release rates comparable to the BFS do not generate such severe storms. In any event, MDCTs, with their lower and more dispersed release areas, would have a smaller potential to create such storms than would NDCTs of similar heat capacity.

5.3.3.6 Noise

The staff estimates that at the nearest residence, noise resulting from the operation of the cooling system will be less than 48 dBA. It is the experience of the staff that such levels are not objectionable and therefore will be acceptable.

5.3.3.7 Summary and Conclusions

The MDCT is a proven, effective, and economical way to dissipate waste heat. The environmental impact of such a tower is minimal, except for the area within a few hundred feet. The staff thus expects that operation of the BFS cooling towers will have a very limited effect on offsite areas (visible plumes aloft). Based on the above analyses, the staff finds the proposed heat dissipation system acceptable and concludes that the resulting impacts will be minimal.

5.4 RADIOLOGICAL IMPACTS

5.4.1 Radiological Impact on Man

The models and considerations for environmental pathways leading to estimates of radiation doses to individuals are discussed in detail in Regulatory Guide 1.109. Similarly, use of these models and additional assumptions for population dose estimates are described in Appendix C of this Statement.

The applicant's site and environmental data provided in the ER and in subsequent answers to NRC staff questions were used extensively in the dose calculations.

5.4.1.1 Exposure Pathways

The environmental pathways which were considered in preparing this section are shown in Figure 5.5. Estimates were made of radiation doses to man at and beyond the site boundary based on NRC staff estimates of expected effluents as shown in Tables 3.4 and 3.5, site meteorological and hydrological considerations, and exposure pathways at the Black Fox Station.

Exposure to radioxenon in the plume and ingestion of food (and water) containing tritium, radiocarbon, radiocesium and radiophosphorus are estimated to account for most of the total body radiation dose commitments to individuals and the population within 50 miles of the station.

5.4.1.2 Dose from Radioactive Releases to the Atmosphere

Radioactive effluents released to the atmosphere from the Black Fox facility will result in small radiation doses to the public. NRC staff estimates of the expected gaseous and particulate releases listed in Table 3.5 and the site meteorological considerations discussed in Section 2.6 of this Statement and summarized in Table 5.5 were used to estimate radiation doses to individuals and populations. The results of the calculations are discussed below.

Radiation Dose Commitments to Individuals

The predicted dose commitments to individuals at selected offsite locations where doses are expected to be largest are listed in Table 5.6. The standard NRC models were used with the following modifications in order to realistically model features of the Black Fox Station design and the site environs. The staff used the results of the applicant's field survey to determine the actual age groups of the receptors at the actual locations for the milk pathway.

Radiation Doses to Populations

The estimated radiation dose commitment to the population (within 50 miles) for the Black Fox Station from gaseous and particulate releases was based on the projected site population distribution for the year 2000 as shown in Figure 5.6 and Figure 5.7. Doses beyond the 50-mile radius were based on average population densities discussed in Appendix C of this Statement. The population doses are presented later in Table 5.9. Background radiation doses are provided for comparison. The doses from atmospheric releases from the Black Fox facility during normal operation represent an extremely small increase in the normal population dose from background radiation sources.

5.4.1.3 Dose Commitments from Radioactive Liquid Releases to Hydrosphere

Radioactive effluents released to the hydrosphere from the Black Fox Station during normal operation will result in small radiation doses to individuals and populations. NRC staff estimates of the expected liquid releases listed in Table 3.4 and the site hydrological considerations discussed in Section 2.5 of this Statement and summarized in Table 5.7 were used to estimate radiation dose commitments to individuals and populations. The results of the calculations are discussed below.

Radiation Dose Commitments to Individuals

The estimated dose commitments to individuals at selected offsite locations where exposures are expected to be largest are listed in Table 5.8. The standard NRC models were used for these analyses with one exception. The actural Broken Arrow intakes are located about 2-1/2 miles downstream of the site in an oxbow--not in the main channel of the Verdigris River. However, to simplify the estimate of the dilution factor at the drinking water intakes, the intakes were conservatively assumed to be located at the entrance to the oxbow, about one mile downstream of the plant discharge.

Radiation Dose Commitments to Populations

The estimated population radiation dose commitments within 50 miles for the Black Fox facility from liquid releases, based on the use of water and biota from the Verdigris and Arkansas Rivers, are shown in Table 5.9. Doses beyond 50 miles were based on the assumptions discussed in Appendix C.

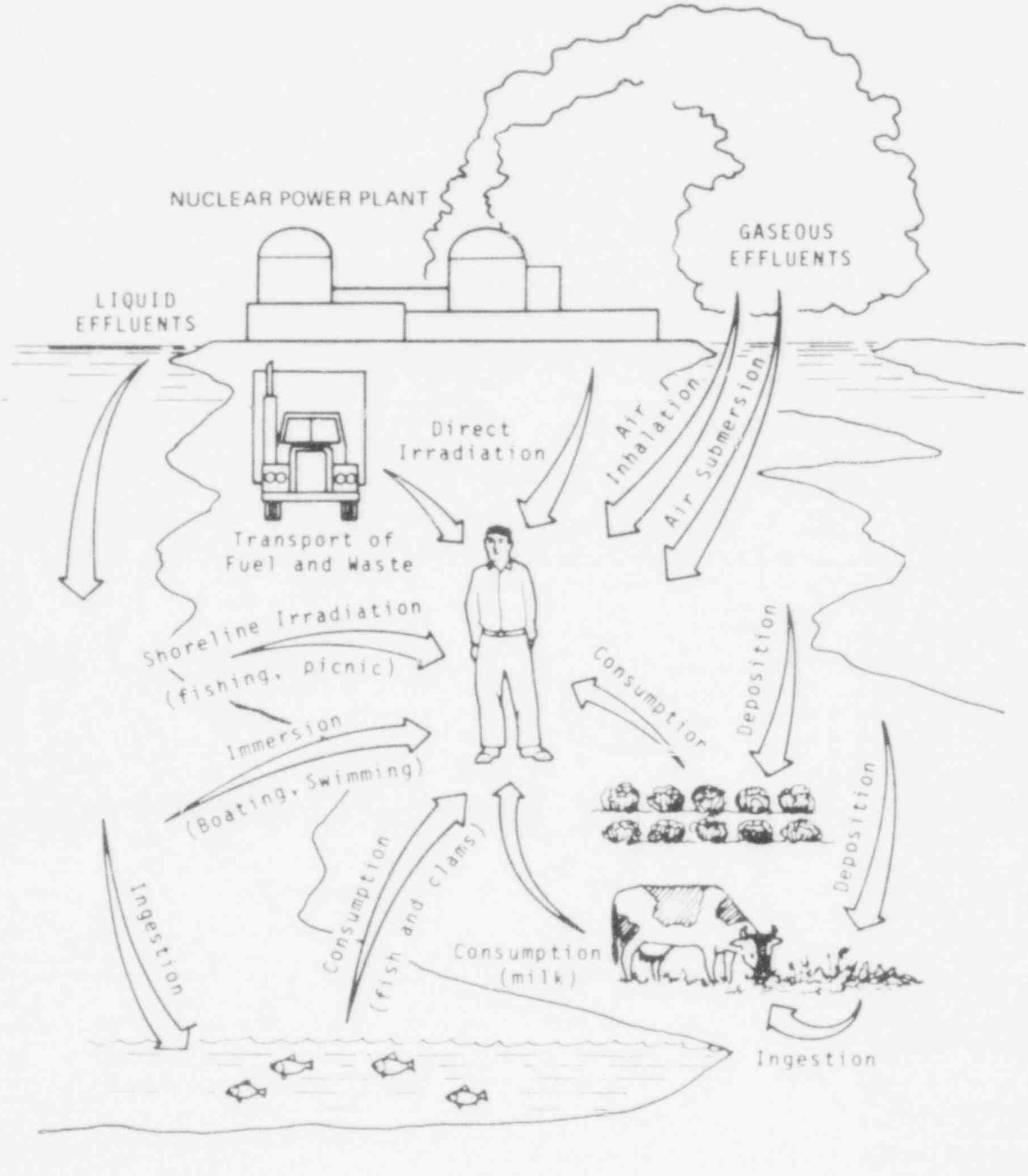


Fig. 5.5. Exposure Pathways to Man.

Table 5.5. Summary of Atmospheric Dispersion Factors and Deposition Values for Selected Locations near the Black Fox Station[a]

| Location[c] | Source[b] | $\chi/Q$, sec/m$^3$ | Relative Deposition, m$^{-2}$ |
|---|---|---|---|
| Nearest Site Boundary | A | $1.1 \times 10^{-6}$ | $1.4 \times 10^{-8}$ |
| (1.1 miles-N) | B | $1.9 \times .0^{-6}$ | $2.4 \times 10^{-8}$ |
| Nearest Residence and Garden | A | $8.0 \times 10^{-7}$ | $9.5 \times 10^{-9}$ |
| (1.3 miles-N) | B | $1.5 \times 10^{-6}$ | $1.7 \times 10^{-8}$ |
| Nearest Milk and Meat Animals | A | $3.5 \times 10^{-7}$ | $2.2 \times 10^{-9}$ |
| (2.0 miles-NNW) | B | $7.6 \times 10^{-7}$ | $4.7 \times 10^{-9}$ |

[a]The doses presented in the following tables are corrected for radioactive decay and cloud depletion from deposition, where appropriate, in accordance with Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Release from Light Water Reactors," March 1976.

[b]Source "A" is Unit Continuous Vent; source "B" is Unit Purge Vent (4-24 hour releases per year).

[c]"Nearest" refers to the type of location where the highest radiation dose is expected to occur from all appropriate pathways.

Background radiation doses are provided for comparison. The doses from liquid releases from the Black Fox Station represent small increases in the population dose from background radiation sources.

5.4.1.4 Direct Radiation

Radiation from the Facility

Radiation fields are produced in nuclear plant environs as a result of radioactivity contained within the reactor and its associated components. Although these components are shielded, dose rates around the plants have been observed to vary from undetectable levels to values of the order of 1 rem/year.

Doses from sources within the plant are primarily due to nitrogen-16, a radionuclide produced in the reactor core. For boiling water reactors, some of the nitrogen-16 is transported with the primary coolant to the turbine building. The orientation of piping, shielding and turbine components in the turbine building determines, in part, the exposure rates outside the plant. Because of variations in equipment layout, exposure rates are strongly dependent upon overall plant design.

Based on the radiation surveys which have been performed around several operating BWRs, it appears to be very difficult to develop a reasonable model to predict doses from scattered and direct radiation from the plant. For newer BWR plants with a standardized design, dose rates have been estimated using sophisticated Monte Carlo techniques. The turbine island design proposed in the Braun Safety Analysis Report[27] is estimated to have direct radiation and skyshine dose rates of the order of 20 mrem per year per unit at a typical site boundary distance of 0.4 mile from the turbine building. This dose rate is assumed to be typical of the new generation of boiling water reactors. The integrated population dose from such a facility would be less than one man-rem per year per unit.

Low-level radioactivity storage containers outside the plant are estimated to contribute less than 0.01 mrem per year at the site boundary.

Table 5.6. Annual Individual Dose Commitments due to Gaseous and Particulate Effluents from Both Units

| Location | Pathway | Dose (mrem/yr) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Total Body | GI-Tract | Bone | Live. | Thyroid | Lung | Skin |
| Nearest* Site Boundary (1.1 miles-N) | Plume | 0.99 | 0.99 | 0.99 | 0.99 | 0.99 | 1.0 | 2.0 |
| | Ground Deposit | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.35 | 0.41 |
| | Inhalation (adult) | ** | ** | * | ** | 0.56 | 0.011 | ** |
| Nearest Residence and Garden (1.3 miles-N) | Plume | 0.68 | 0.68 | 68 | 0.68 | 0.68 | 0.69 | 1.4 |
| | Ground Deposit | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.24 | 0.28 |
| | Inhalation (child) | ** | ** | ** | ** | 0.51 | ** | ** |
| | Vegetation (child) | 0.39 | 0.36 | 1.9 | 0.50 | 3.1 | 0.35 | 0.34 |
| Nearest Milk and Meat Animals (2.0 miles-NNW) | Plume | 0.26 | 0.26 | 0.26 | 0.26 | 0.26 | 0.26 | 0.53 |
| | Ground Deposit | 0.054 | 0.054 | 0.054 | 0.054 | 0.054 | 0.054 | 0.064 |
| | Inhalation (child) | ** | ** | ** | ** | 0.23 | ** | ** |
| | Vegetation (child) | 0.16 | 0.15 | 0.78 | 0.19 | 0.79 | 0.15 | 0.15 |
| | Meat (child) | 0.024 | 0.024 | 0.12 | 0.025 | 0.14 | 0.023 | 0.023 |
| | Goat Milk (child) | 0.11 | 0.078 | 0.48 | 0.21 | 11. | 0.085 | 0.074 |

*"Nearest" refers to that type of location where the highest radiation dose is expected to occur from all appropriate pathways.

**Less than 0.01 mrem/yr.

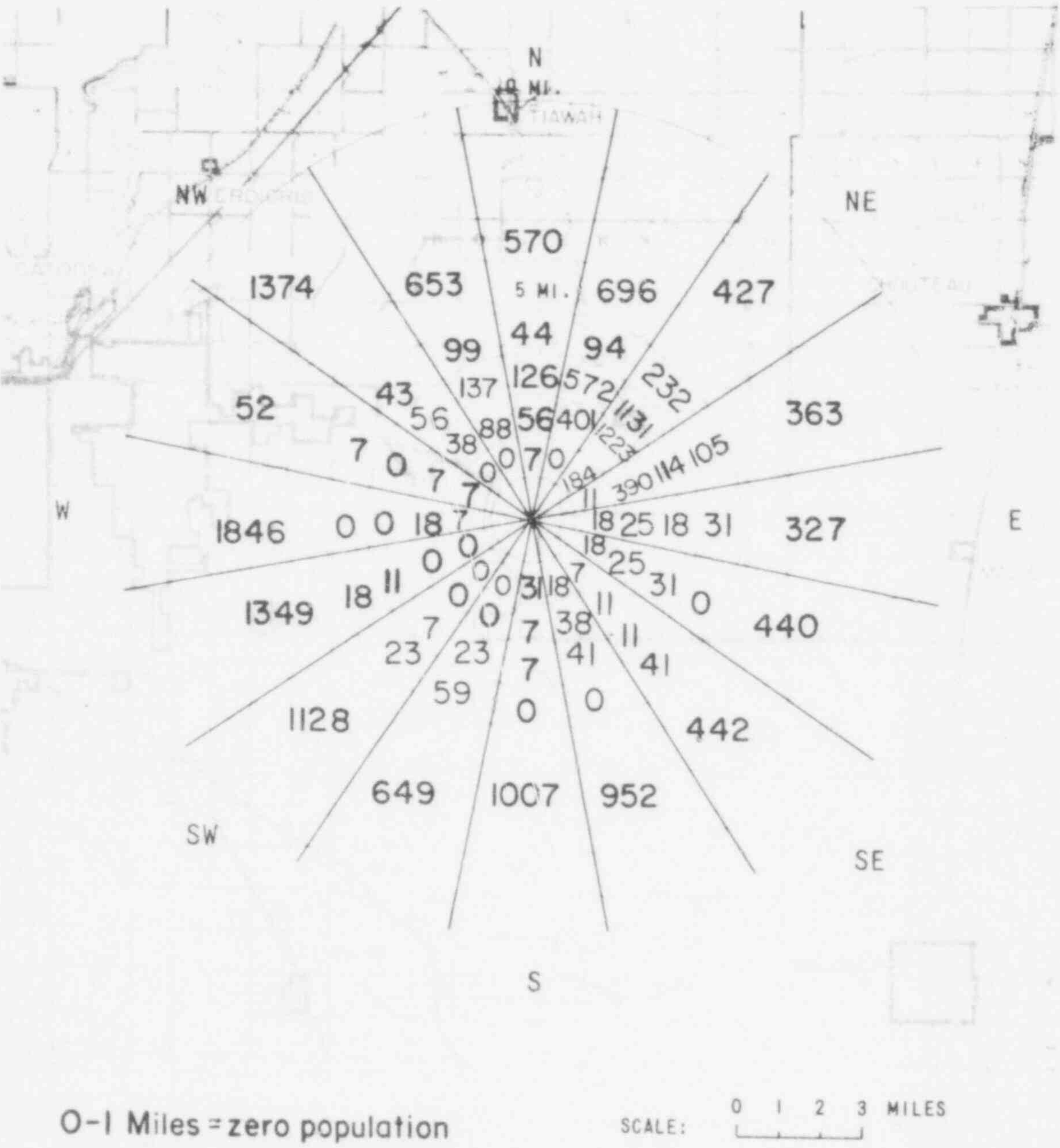


Fig. 5.6. Year 2000 Population Distribution within Ten Miles of Black Fox Station.



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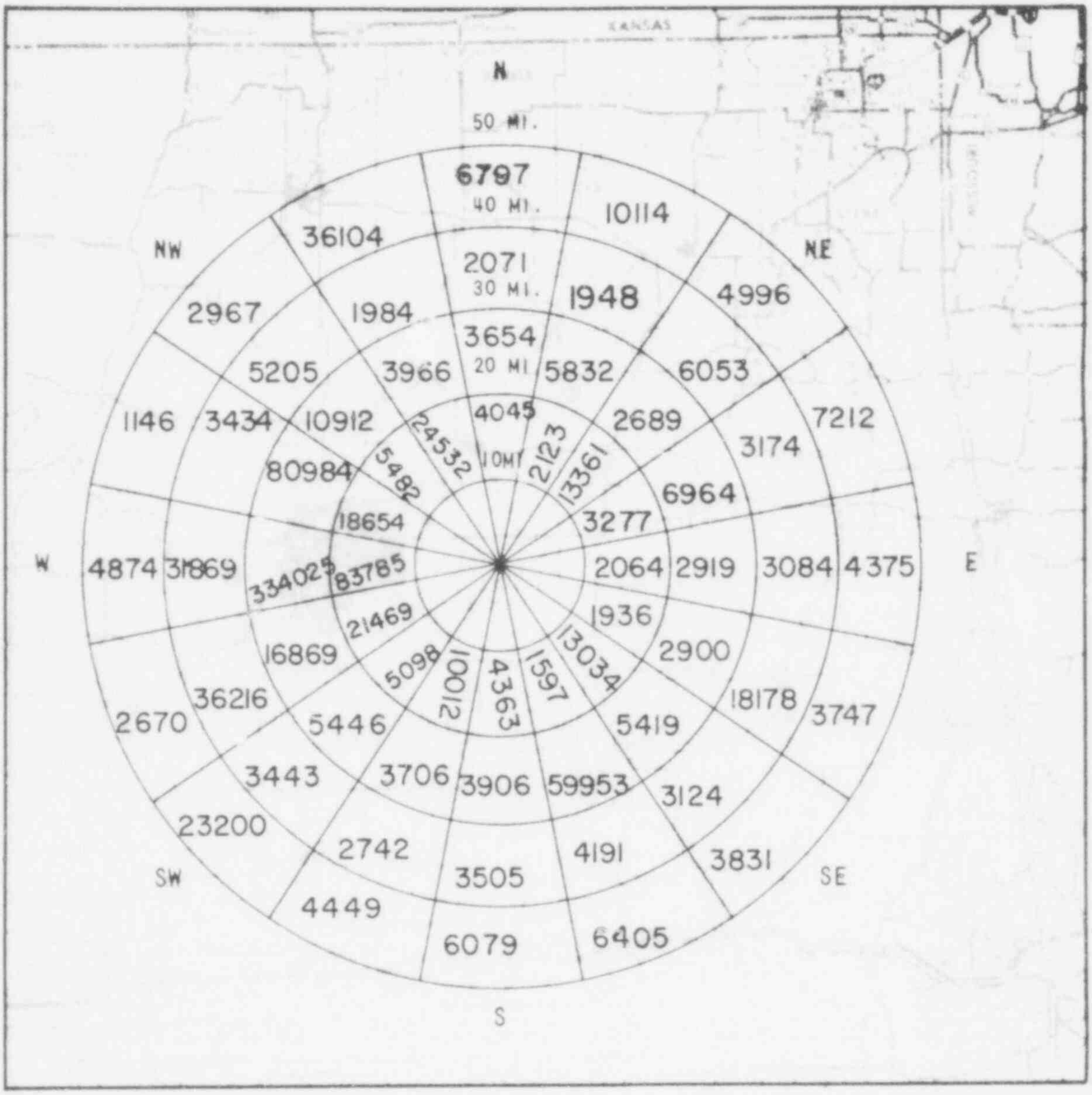


Fig. 5.7. Year 2000 Population Distribution within 50 Miles of Black Fox Station.

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Table 5.7. Summary of Hydrologic Transport and Dispersion for Liquid Releases from the Black Fox Station[a]

| Location | Transit Time, hours[b] | Dilution Factor |
|---|---|---|
| Nearest drinking water intake (Broken Arrow) (1 mi downstream on Verdigris R.) | 24 | 345 |
| Nearest sport fishing location (Channel View #2) | 24 | 15 |
| Nearest shoreline (Channel View #2) | 24 | 15 |
| Nearest irrigated crops (2.5 mi S on river) | 24 | 345 |

[a]See Regulatory Guide 1.113, "Estimating the Aquatic Dispersion of Effluents from Accidental and Routine Reactor Releases for the Purpose of Implementing Appendix I," May 1976.

[b]Includes 24-hour retention by wastewater holdup pond before release to river.

Occupational Radiation Exposure

Based on a review of the applicant's safety analysis report, the staff has determined that the applicant is committed to design features and operating practices that will assure that individual occupational radiation doses (occupational dose is defined in 10 CFR Part 20) and that individual and total plant population doses will be as low as is reasonably achievable.* For the purpose of portraying the radiological impact of the plant operation on all onsite personnel, it is necessary to estimate a man-rem occupational radiation dose. For a plant designed and proposed to be operated in a manner consistent with the 10 CFR Part 20, there will be many variables which influence exposure and make it difficult to determine a quantitative total occupational radiation dose for a specific plant. Therefore, past exposure experience from operating nuclear power stations[28] has been used to provide a widely applicable estimate to be used for all light water reactor power plants of the type and size of Black Fox Station. This experience indicates a value of 500 man-rem per year per reactor unit.

On this basis, the projected occupational radiation exposure impact of the two unit Black Fox Station is estimated to be 1000 man-rem per year.

Transportation of Radioactive Material

The transportation of cold fuel to a reactor, of irradiated fuel from the reactor to a fuel reprocessing plant, and of solid radioactive wastes from the reactor to burial grounds to within the scope of the NRC report entitled, "Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants." The environmental effects of such transportation are summarized in Table 5.10.

5.4.1.5 Evaluation of Radiological Impact

The radiological impact of operating the proposed Black Fox Station is presented in terms of individual doses in Table 5.6 and Table 5.8. and population dose commitments in Table 5.9. The annual individual doses resulting from routine operation of the plant are a small fraction of the dose limits specified in 10 CFR Part 20. The population doses are small fractions of the dose from natural environmental radioactivity. As a result, the staff concluded that there will be no measurable radiological impact on man from routine operation of the Black Fox Station.

*10 CFR Part 20, Standards for Protection Against Radiation.

Table 5.8. Annual Individual Dose Commitments due to Liquid Effluents from Both Units

| Location | Pathway | Dose mrem/yr | | | | | |
|---|---|---|---|---|---|---|---|
| | | Total Body | Bone | Liver | Thyroid | Lung | GI Tract |
| Nearest drinking water use (Broken Arrow) (3 mi downstream) | Drinking water (infant) | a/ | a/ | a/ | 0.87 | a/ | a/ |
| Nearest fish production (Channel View, outfall area) | Fish ingestion (adult) | 0.016 | 0.28 | 0.027 | 1.6 | a/ | 0.033 |
| Nearest shoreline (Channel View) | Sediments | a/ | a/ | a/ | a/ | a/ | a/ |
| Nearest use of irrigated food crops (3.5 mi S) | Irrigation water-food crops (child) | a/ | a/ | a/ | a/ | a/ | a/ |

[a] Less than 0.01 mrem/yr.

Table 5.9. Annual Population Dose Commitments in the Year 2000 from Both Units

| Category | Population Dose Commitment, man-rem | |
|---|---|---|
| | 50 Miles | U. S. Population |
| Natural Radiation Background[a] | $1.1 \times 10^5$ [b] | $2.6 \times 10^7$ [c] |
| Black Fox Station | | |
| Plant work force | d/ | 1000 |
| General public | 6 | 8 |
| Noble gases | 6 | 8 |
| Inhalation | e/ | e/ |
| Ground deposition | e/ | e/ |
| Terrestrial foods | e/ | 51 |
| Drinking water | e/ | e/ |
| Aquatic foods | e/ | e/ |
| Recreation | e/ | e/ |
| Transportation of nuclear fuel and radioactive wastes | d/ | 7 |

[a] "Natural Radiation Exposure in the United States," U. S. Environmental Protection Agency, ORP-SID 72-1 (June 1972).

[b] Using the average Oklahoma State background dose (109 mrem/yr) in Ref (a), and year 2000 projected population from Figure 5.7.

[c] Using the average U. S. background dose (102 mrem/yr) in Ref. (a), and year 2000 projected U. S. population from "Population Estimates and Projections," Series II, U. S. Dep. of Commerce, Bureau of the Census, Series P-25, No. 541, (February 1975).

[d] Included in the U. S. population, since some exposure is received by persons residing outside 50 mile radius.

[e] Less than 1 man-rem/yr.

5.4.1.6 Comparison of Calculated Doses with NRC Design Objectives

For the purpose of determining compliance with Appendix I to 10 CFR 50, the applicant has decided to exercise the option described in the Amendment to Appendix I dated September 4, 1975. By virtue of this option, the Section II.D cost/benefit requirement of Appendix I is fulfilled if the calculated individual doses are within the dose design objectives stated in RM-50-2.[29]

Tables 5.11 and 5.12 show a comparison of calculated doses from routine releases of liquid and gaseous effluents from the Black Fox Station with the design objectives of Appendix I to 10 CFR 50 and with the proposed staff design objectives of RM-50-2.

5.4.2 Radiological Impact on Biota Other Than Man

The models and considerations for environmental pathways leading to estimates of radiation doses to biota are discussed in detail in Volume 2, "Analytical Models and Calculations" of WASH-1258.[30]

5.4.2.1 Exposure Pathways

The environmental pathways which were considered in preparing this section are shown in Figure 5.8. Dose estimates were made for biota at the nearest boundary of the site, and in the aquatic environment at the point where the station's liquid effluents mix with the Verdigris River. The estimates were based on estimates of expected effluents as shown in Tables 3.4 and 3.5, site meteorological and hydrological considerations, and the exposure pathways anticipated at the Black Fox Station.

Table 5.10. Environmental Impact of Transportation of Fuel and Waste to and from One Light-Water-Cooled Nuclear Power Reactor[a]

| Normal Conditions of Transport | |
|---|---|
| Heat (per irradiated fuel cask in transit) | 250,000 Btu/hr |
| Weight (governed by Federal or State restrictions) | 73,000 lb per truck; 100 tons per cask per rail car. |
| Traffic density | |
| Truck | Less than 1 per day |
| Rail | Less than 3 per month |

| Exposed Population | Estimated Number of Persons Exposed | Range of Doses to Exposed Individuals[b] (per reactor year) | Cumulative Dose to Exposed Population (per reactor year)[c] |
|---|---|---|---|
| Transportation workers | 200 | 0.01 to 300 millirem | 4 man-rem |
| General public | | | |
| Onlookers | 1,100 | 0.003 to 1.3 millirem | 3 man-rem |
| Along route | 600,000 | 0.0001 to 0.06 millirem | |

[a]Data supporting this table are given in the Commission's "Environmental Survey of Transportation of Radioactive Materials To and From Nuclear Power Plants," WASH-1238, December 1972 and Supp. I, NUREG 75/038, April 1975.

[b]The Federal Radiation Council has recommended that the radiation doses from all sources of radiation other than natural background and medical exposures should be limited to 5000 millirem per year for individuals as a result of occupational exposure and should be limited to 500 millirem per year for individuals in the general population. The dose to individuals due to average natural background radiation is about 130 millirem per year.

[c]Man-rem is an expression for the summation of whole-body doses to individuals in a group. Thus, if each member of a population group of 1000 people were to receive a dose of 0.001 rem (1 millirem), or if two people were to receive a dose of 0.5 rem (500 millirem) each, the total man-rem in each case would be 1 man-rem.

#### 5.4.2.2 Doses to Biota from Radioactive Releases to the Biosphere

Depending on the pathway (as discussed in Regulatory Guide 1.109), terrestrial and aquatic biota will receive doses approximately the same or somewhat higher than man receives. Dose estimates for some typical biota at the Black Fox site are shown in Table 5.13. Doses to a greater number of similar biota in the offsite environs will generally be much lower.

Doses to Biota from Direct Radiation

Although many of the terrestrial species may be continuously exposed, and thereby receive higher doses than man, aquatic species and some terrestrial species may receive somewhat lower doses depending on shielding by water or soil (e.g., burrows). As a result of these uncertainties, it was assumed that the direct radiation doses to biota at the site boundary will be about the same as for man. As discussed in Section 5.4.1.4, direct radiation doses will generally be about 20 mrad/yr.

Evaluation of the Radiological Impact on Biota[31,32]

Although guidelines have not been established for desirable limits for radiation exposure to species other than man, it is generally agreed that the limits established for humans are also conservative for other species. Experience has shown that it is the maintenance of population stability that is crucial to the survival of a species, and species in most ecosystems suffer

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Table 5.11. Comparison of Calculated Doses to a Maximum Individual from Black Fox Station Operation with Guides for Design Objectives Proposed by the Staff[a]

| Criterion | RM-50-2 Design Objectives | Calculated Dose |
|---|---|---|
| Liquid Effluents | | |
| Dose to total body or any organ from all pathways | 5 mrem/yr | 1.6 mrem/yr |
| Gaseous Effluents | | |
| Gamma dose in air | 10 mrad/yr | 1.5 mrad/yr |
| Beta dose in air | 20 mrad/yr | 1.2 mrad/yr |
| Dose to total body of an individual | 5 mrem/yr | 0.99 mrem/yr |
| Dose to skin of an individual | 15 mrem/yr | 2.0 mrem/yr |
| Radioiodine and Particulates[b] | | |
| Dose to any organ from all pathways | 15 mrem/yr | 12. mrem/yr |

[a]Guides on Design Objectives proposed by the NRC staff on February 20, 1974; considers doses to individuals from all units on site. From "Concluding Statement of Position of the Regulatory Staff," Docket No. RM-50-2, Feb. 20, 1974, pp. 25-30, U. S. Atomic Energy Commission, Washington, D. C.

[b]Carbon-14 and tritium have been added to this category.

Table 5.12. Comparison of Calculated Doses to a Maximum Individual from Operation of Each Unit of Black Fox Station with Appendix I Design Objectives[a]

| Criterion | Appendix I Design Objectives | Calculated Dose |
|---|---|---|
| Liquid Effluents | | |
| Dose to total body from all pathways | 3 mrem/yr | 0.016 mrem/yr |
| Dose to any organ from all pathways | 10 mrem/yr | 1.6 mrem/yr |
| Noble Gas Effluents | | |
| Gamma dose in air | 10 mrad/yr | 0.75 mrad/yr |
| Beta dose in air | 20 mrad/yr | 0.60 mrad/yr |
| Dose to total body of an individual | 5 mrem/yr | 0.49 mrem/yr |
| Dose to skin of an individual | 15 mrem/yr | 1.0 mrem/yr |
| Radioiodine and Particulates[b] | | |
| Dose to any organ from all pathways | 15 mrem/yr | 6.2 mrem/yr |

[a]Appendix I Design Objectives from Sections II.A, II.B, II.C of Appendix I, 10 CFR Part 50; considers doses to maximum individual per reactor unit. From Federal Register V. 40, p. 19442, May 5, 1975.

[b]Carbon-14 and tritium have been added to this category.

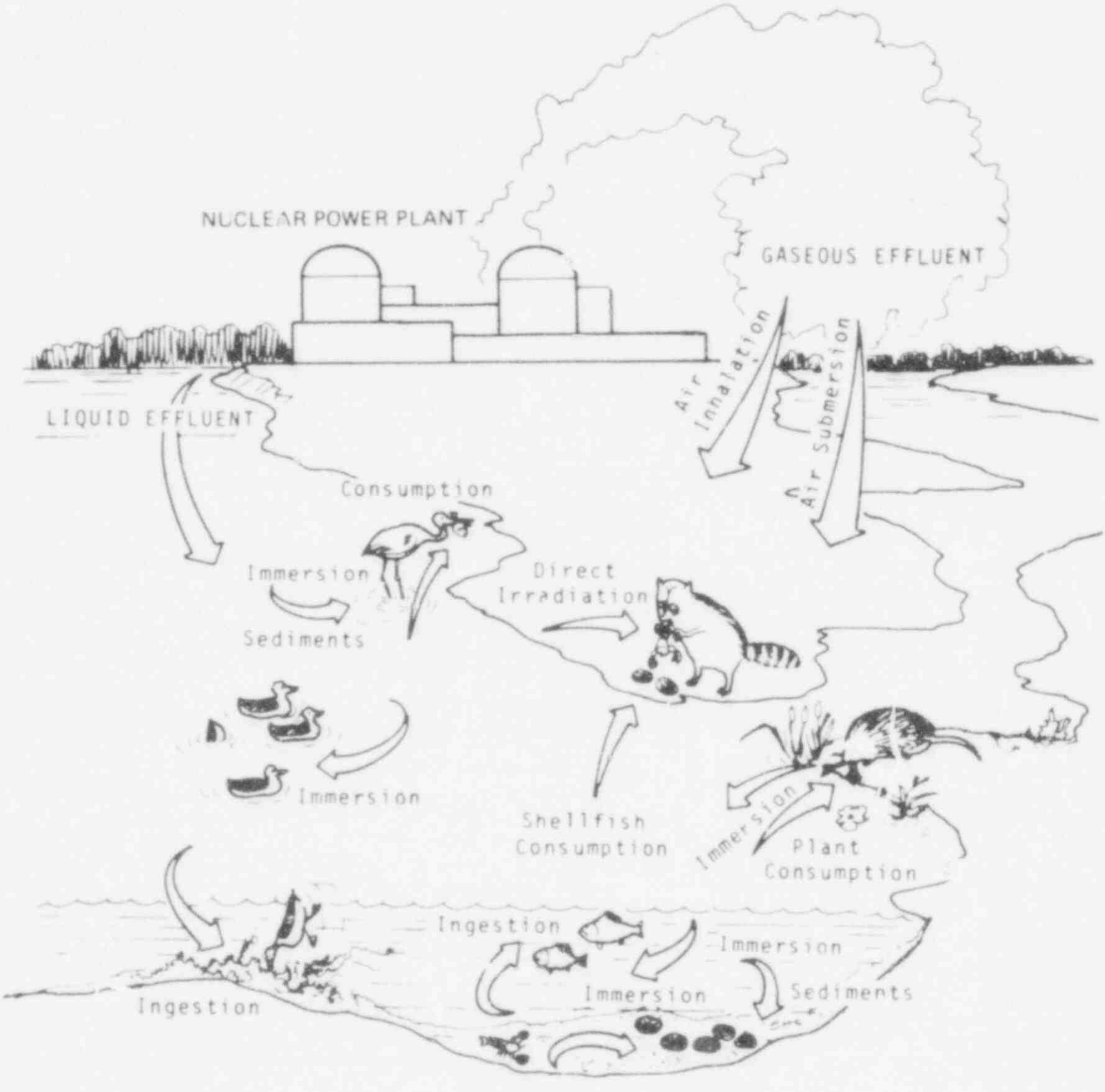


Fig. 5.8. Exposure Pathways to Biota Other Than Man.

Table 5.13. Dose Estimates for Typical Biota at Black Fox Station Site

| Biota | Location | Pathway[a] | Dose, mrad/yr |
|---|---|---|---|
| Deer | Nearest site boundary (1.1 mi N) | Atmosphere | 1.5 |
| Fox | " | " | 1.4 |
| Terrestrial flora | " | " | 2.0 |
| Raccoon | | Atmosphere<br>Hydrosphere | 1.3<br>0.41 |
| Muskrat | " | " | 1.3<br>10. |
| Duck | Plant outfall (Verdigris R.) | " | 1.3<br>10. |
| Fish | " | Hydrosphere | 1.7 |
| Invertebrates | " | " | 1.2 |
| Algae | " | " | 6.8 |

[a]Atmospheric doses include estimates of plume dose, ground deposition dose, inhalation dose, and ingestion doses where appropriate. Hydrospheric doses include estimates of immersion dose, dose from consumption, and sediment dose where appropriate.

rather high mortality rates from natural causes. While the existence of extremely radiosensitive biota is possible and while increased radiosensitivity in organisms may result from environmental interactions with other stresses (e.g., heat, biocides), no biota have yet been discovered that show a sensitivity (in terms of increased disease or death) to radiation exposures as low as those expected in the area surrounding the Black Fox Station. The "BEIR" Report concluded that the evidence to date indicates that no other living organisms are very much more radiosensitive than man; therefore, no measurable radiological impact on populations of biota is expected from the radiation and radioactive materials released to the biosphere as a result of the routine operation of the Black Fox Station.

## 5.5 NONRADIOLOGICAL EFFLUENTS

### 5.5.1 Water Quality Standards and Effluent Limitations

#### 5.5.1.1 State Standards

Water quality standards were adopted by the Oklahoma Water Resources Board in 1973. A request for formal approval of these standards was made to the regional administrator of the U. S. Environmental Protection Agency and has been approved. Details of the standards can be found in Publication 52 of the Oklahoma Water Quality Standards.

Table 5.14 gives the composition of the effluent from the wastewater holding pond to the Verdigris River and the resultant composition after complete mixing with the low and average river flow. Also given in the table are some instream State water-quality standards. It can be seen that the concentrations of sulfate in the river after complete mixing will exceed State instream standards during the times of minimum flow.

Table 5.15 shows a comparison of the concentration of some trace elements in the discharge to the river with State wastewater guidelines for intermittent streams. With the exception of Cr and Ni, which originate from the corrosion of the stainless steel condenser tubes, the concentrations of trace substances result from the ninefold concentration of river water in the cooling system. Table 5.15 shows that Ba, Cd, F, and Hg will exceed the guidelines. The guidelines are for comparison and do not represent applicable rules.

The staff has considered mitigation of excess concentrations using zero blowdown techniques such as sidestream purification for removal of salts. The staff is unaware of any plants that have used these processes on the scale required. The technologies are untested and it is staff's judgment that the costs are high and are not justified by the benefits attained.

Table 5.14. Plant Discharge and Verdigris River Water Quality Before and After Mixing[a]

| Parameter | Discharge from Waste-water Pond Before Mixing | Upstream of Discharge | | Downstream of Discharge | | Oklahoma Water Quality Standards[b] |
|---|---|---|---|---|---|---|
| | | 379 cfs | 2000 cfs | 379 cfs | 2000 cfs | |
| Calcium | 321 | 44 | 40 | 53 | 41 | -- |
| Magnesium | 59 | 8.2 | 7.3 | 10 | 7.6 | -- |
| Sodium | 199 | 29 | 23 | 34 | 24 | -- |
| Bicarbonate (as $CaCO_3$) | 1046 | 112 | 97 | 115 | 98 | -- |
| Sulfate | 829 | 39 | 34 | 61 | 37 | 45 |
| Chloride | 300 | 47 | 37 | 55 | 38 | 80 |
| Nitrate | 0.4 | 0.51 | 0.51 | 0.61 | 0.52 | c/ |
| Silica | 53 | 6.5 | 6.5 | 7.9 | 6.7 | -- |
| Phosphate ($PO_4$) | 7.7 | 0.3 | 0.3 | 0.53 | 0.33 | c/ |
| TDS | 2240 | 310 | 266 | 362 | 273 | 367 |
| pH | -- | -- | -- | 6.5-8.5 | 6.5-8.5 | 6.5-8.5 |
| Dissolved oxygen | -- | -- | 9 | -- | 9 | 5 |

[a]All values given as mg/l, except pH given in standard units.

[b]Instream numerical criteria limits to be maintained at all times except when the flow is equal to or less than the 7-day, 2-year flow or when the flow rate is not significant or discernable by the naked eye.

[c]Total phosphorus and nitrogen/phosphorus ratio limited to prevent eutrophication problems.

Modified from ER, Table 5.3-6.

Table 5.15. Comparison of Trace Element Concentration in River Water and in BFS Discharge with State Wastewater Guidelines[a]

| Element | River Water[b] | | Discharge | Oklahoma State Wastewater Discharge Guidelines[c] |
|---|---|---|---|---|
| | Analysis #1 | Analysis #2 | | |
| As | 0.025 | - | 0.19 | 0.2 |
| Ba | 0.84 | <0.4 | 6.4 | 5.0 |
| Cd | 0.022 | <0.001 | 0.17 | 0.03 |
| Cr ( , or III) | 0.002[d] | - | 0.83 | 1.0 |
| Cu | 0.005 | 0.004 | 0.04 | 0.1 |
| F | 0.3[d] | - | 2.3 | 1.0 |
| Fe | 0.28 | 0.5 | 3.8 | - |
| Pb | 0.085 | 0.007 | 0.6 | 0.1 |
| Mn | 0.017 | 0.009 | 0.13 | 0.2 |
| Ni | 0.001[d] | - | 0.5[e] | 1.0 |
| Hg | 0.0006 | 0.0017 | 0.13 | 0.005 |
| Zn | 0.08 | 0.0029 | 0.6 | 1.0 |

[a]All values expressed as mg/l.

[b]River water concentrations based on two analyses, June 18 (Analysis #1) and August 13 (Analysis #2), in 1974 (ER, Tables 2.4.12 and 2.4.13).

[c]Oklahoma State Wastewater Discharge Guidelines for discharges into intermittent streams and storm sewers.

[d]Maximum of 11 samples, February through December, 1974.

[e]Calculated from condenser tube corrosion and is an upper limit.

Modified from ER, Tables 2.4-12 and 2.4-13.

The organic scale inhibitors to be added are generally long chain polymers whose modes of operation or final state are not clearly understood. More particularly, properties such as toxicity and biodegradability are not known. In view of the general lack of knowledge about these substances, the staff will require that the applicant show to the staff's satisfaction, before the plant is operated, that the inhibitors to be used will not have an adverse effect on the river, and will not be toxic.

On the basis of the size and thermal efficiency of fossil-fueled generating plants, the staff estimates the water consumption of the Northeast 3 and 4 plants will be about 20% of the consumption of the Black Fox plant. Increments in the salt concentration of the Verdigris River due to the Northeast plants will be approximately .2 of the differences shown between the upstream and downstream columns of Table 5.1.4 and will be well within normal concentration fluctuations of the river.

Thermal standards are treated in Section 5.3.2.

### 5.5.1.2 Federal Effluent Guidelines and Standards

The EPA has published regulations concerning thermal discharges and effluent guidelines for steam electric power generating plants.[33] The staff has evaluated effluents associated with the construction and operation of the facility. These effluents are expected by the staff to conform to the limitations and reflect the "best available technology economically achievable" [10 CFR §423-13(1)]. Assessment of the effects of the effluents are reported in this Environmental Statement. In some instances the development of specific operating limitations may have to be incorporated in the technical specifications of the operating licenses.

### 5.5.2 Sanitary Wastes

The proposed sanitary system is expected to meet EPA guidelines for municipal waste-treatment effluent quality as well as Oklahoma State Department of Health and Oklahoma Water Resources Board water quality standards. The staff expects that no adverse environmental impacts will result from proper operation of the system.

### 5.5.3 Gaseous Pollutants

The Black Fox Station is in a region of high photochemical oxidant level in the air. Other than possible ozone formation by high-voltage transmission lines, the only known potential source of photochemical oxidant emissions would be from the operation of emergency diesel generators (see Sec. 3.6.2.2). These engines will emit hydrocarbons that are indirectly involved in oxidant formation and nitrogen oxides that are themselves oxidants. EPA emission standards are not available for large stationary diesel sources; however, the applicant expects to meet EPA standards for large mobile units.[35] Since the proposed diesel units will be operated only for emergencies and testing, the contribution to photochemical oxidant levels should be very small. Nevertheless, the staff recommends that the applicant employ state-of-art engines designed for low emission levels, so that the BFS does not contribute to the declining air quality of the region.

## 5.6 BIOTIC IMPACTS OF STATION OPERATION

### 5.6.1 Terrestrial

#### 5.6.1.1 Cooling Tower Effects

Based on the staff's analysis of the atmospheric effects of the cooling towers (Sec. 5.3.3), the majority of ground-level fogging and icing, drift, and salt deposition will occur on an area presently occupied by upland pasture and shrub-invaded grasslands. A portion of this area will be utilized as a construction parking facility. However, there is no direct evidence of any biological impact of drift.[a] The staff agrees with the applicant's prediction that there is a very low probability of direct biological damage due to drift and/or salt deposition.

Icing induced by cooling towers is not expected to have a detectable effect compared with natural icing during freezing rains.

#### 5.6.1.2 Vegetational Changes

Virtually all of the BFS site is presently grazed by beef cattle or harvested as hay. Since all livestock will be removed from the entire BFS site prior to operation, grazing pressure will be removed for the life of BFS. The applicant concludes that "there will be a beneficial commitment of the site . . . to more productive ecosystems than those associated with pre-existing site uses" (ER, Sec. 5.7.4.1, p. 5.7-4). The applicant further describes how the site may revert to native communities following the removal of the livestock (ER, Sec. 2.2.3.1.3.1.4, pp. 2.2-17, -18), and offers speculations on the effects on wildlife habitats (ER, pp. 2.2-52, -57, -58, -60 and -79), especially on the habitats of threatened species (ER, pp. 2.2-64, and -73). To evaluate these postulated effects of removal of grazing from the BFS site, the staff has employed multivariate, indirect ordination analyses[36-38] of the applicant's vegetational data and data from several offsite locations (ER, Tables 2.2-8 and 2.2-9).

Based on these ordinational analyses, the staff concludes that the vegetation patterns in the vicinity of the BFS site can be explained by two gradients: (1) disturbance, and (2) moisture. The approximate location of the BFS site communities with respect to these two gradients is shown in Figure 5.9. The source of the disturbance is primarily grazing, although other forms of disturbance, such as logging and the introduction of exotic species (Bermuda grass), affect the vegetational communities of the BFS site. Natural succession will tend to move any community vector along a disturbance gradient toward native communities if the source of the disturbance is removed. The staff conclusions concerning the BFS site potential for recovery from disturbance

[a]"Nuclear Energy Center Site Surveys - 1975, Part III: Technical Considerations," U. S. NRC, Office of Special Studies, p. 3-72, January 1976.

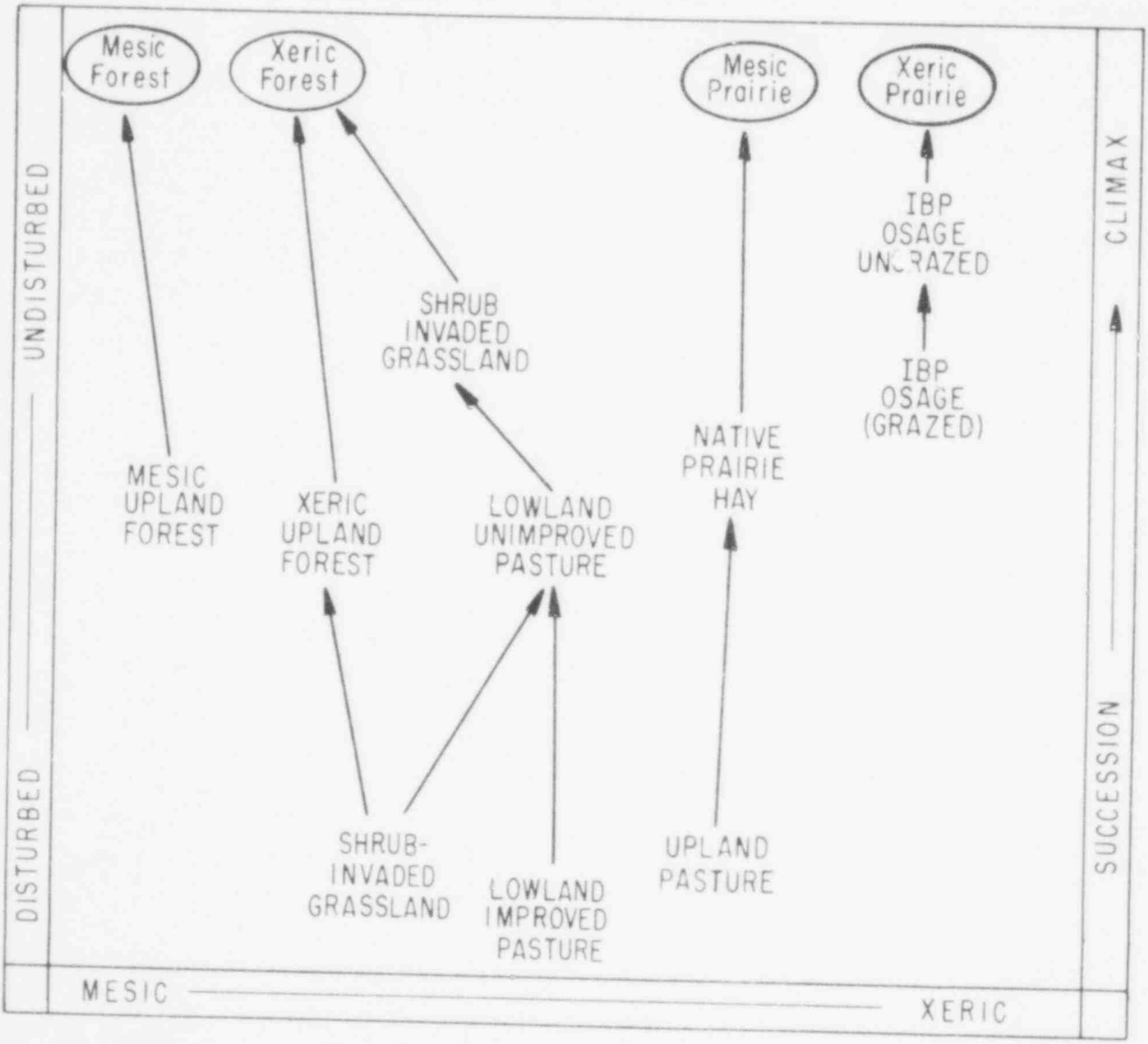


Fig. 5.9. The Two Gradients in BFS Vegetation. [Arrows depict probable successional changes (see text).]

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are summarized in Figure 5.9 (see also Ref. 39), which implies that as the community vectors undergo successional movement, there is no movement with respect to moisture. While it is generally true that the location of the community vector with respect to moisture should not change as a function of succession, moisture status will change as a function of weather. The weather of Oklahoma, especially the annual precipitation, is highly variable and unpredictable.[40] Because of the location of the BFS site compared with the Forest-Prairie Border, wet years should favor succession toward forest communities, and dry years would favor succession toward grassland communities.

For the communities that are intermediate with respect to moisture (Plots E and H, Table G-1), successional recovery may show an apparent shift toward mesic because of invasion by woody species and subsequent invasion by forest species.[39]

Therefore, the staff concludes that the BFS site forests (Plots A and B, Table G-1 of Appendix G) should revert to native climax forest communities, and that the site native prairie (Plot D, Table G-1) and upland pasture (Plot F, Table G-1) should revert to native subclimax prairie.[39] Both of these changes will result in improved wildlife habitat. The lowland pastures (Plots E and H, Table G-1) will probably become shrub-invaded grasslands, thereby producing a brushy, forest edge type of habitat (suitable for white-tail deer, etc.).[40]

The staff compared the results of its ordination of the BFS vicinity forests with ordinations[41] of representative forest stands[42] for the entire State of Oklahoma. The staff concludes from this comparison that the mesic BFS forest is unusual, and following Blair,[43] can be considered as a "unique" habitat comparable to the forests described by Blair for the "Lost City" region along the Arkansas River.

### 5.6.2 Aquatic

#### 5.6.2.1 Intake

Entrapment

Since the outermost screen of the intake structure will be fixed and of a fine mesh (3/8 of an inch), and since there will be no water-containment structures in front of the screen, there will be no potential for fish entrapment.

Impingement

Some aquatic organisms (mostly fish) larger than 3/8 of an inch swimming too near the intake may be unable to outswim the normal approach velocities of 0.5 to 0.75 ft/sec and will be impinged upon the intake screens. Most of the fish thus caught will be unable to escape and will eventually die from exhaustion and/or suffocation. Nevertheless, impingement should be minimal because of the small fish population in the river (ER, Table 2.2-110), low intake velocity, the absence of trash racks and preliminary treatment chambers that might trap fish, the smooth surface of the intake screen plates, the orientation of the intake screens parallel to normal river flow, mid-depth location of intake screens, and the small area of intake influence relative to the area available for fish movement (ER, p. 5.1-11). Impingement should be limited to fish in poor physical condition and very small fish and other organisms with little or no ability for self-propulsion. Appendix D provides a more detailed analysis of impingement potentials at the BFS, as low as they are.

Entrainment

Entrainment will be limited to small organisms, such as phytoplankton, zooplankton, drifting macroinvertebrates, and fish eggs and larvae. Some organisms will become established in the presettling pond rather than being immediately passed through the cooling system. When the entrained organisms pass through the cooling system, they will be subjected to lethal thermal, mechanical, and chemical shocks. Regardless of the immediate fate of the entrained organisms, they can be considered lost from the Verdigris River. If one assumes uniform distribution of these organisms in the river, the relative loss from the river ecosystem will be a function of the percentage of the river water withdrawn.

On the basis of the normal operation makeup rate of 50 cfs (22,440 gpm) and monthly mean-flow rates taken at Newt Graham Lock and Dam from September 1970 to December 1974,[44-47] withdrawal by BFS will range from 7.9% (August) to 0.4% (March and November), with an average of 1.4%.

Entrainment losses from this withdrawal range should not be detrimental to the biota of the Verdigris River, as will be discussed in the following paragraphs. It should be noted, however, that withdrawal rates can be expected to be as large as 16.4% under conditions of maximum makeup water requirements (62 cfs, or 28,000 gpm) and guaranteed regulated low flow (379 cfs, or 170,107 gpm). The staff is aware that withdrawal rates of this extent could have detrimental impacts to the river biota, but realize that occasionally maximum withdrawal rates will be unavoidable.

The nature and extent of impacts will, in large part, depend upon the time of year and duration of maximum withdrawal. Planktonic populations will be directly influenced by maximum withdrawal. Considering high recruitment capabilities and short generation time, coupled with the fact that species are not homogeneously distributed under actual conditions, it is doubtful whether maximum withdrawal rates will severely affect the planktonic community. It is possible that planktonic production in backwater areas and/or in the Oologah Reservoir could offset losses due to entrainment. Macroinvertebrates and fish would be less affected by periods of maximum withdrawal than plankton because of distribution patterns and/or mobility. Although the staff believes maximum withdrawal should not have a major adverse effect upon the river biota, it is recommended that the applicant make every effort feasible to curtail the need for maximum water withdrawal during times of guaranteed low flow. The staff also recommends that the applicant monitor planktonic populations during and after maximum withdrawal periods as part of the required entrainment monitoring program to assess the extent that river biota will be affected.

Phytoplankton concentrations in the Verdigris River were sparse throughout the year, having an average density of 200 organisms/ml. Zooplankton concentrations were moderate, averaging 11,100 individuals per cubic meter. Based on the applicant's 1974 data and calculations, approximately 90,000 pounds of phytoplankton and 22,000 pounds of zooplankton are expected to be entrained annually (ER, Appendix 10B). Since the staff conservatively assumes that all entrained plankton will be lost during plant operation, it estimates the worst-case loss of plankton in the vicinity of the station will not exceed 16.4%. Entrainment losses should be greatest during the summer months when BFS withdraws a higher percentage of the Verdigris. During these months, conditions most favorable for plankton reproduction should exist, and thus rapid reproduction rates (a few hours to several days) should offset moderate mortality rates due to entrainment. Considering the high recruitment capabilities of planktonic organisms in relation to their moderate population densities in the river, and considering the low quantities of water to be withdrawn, the staff concludes that the loss of the entrained phytoplankton and zooplankton will not be detrimental to the Verdigris River ecosystem.

The mid-water-depth intake will limit entrainment of macroinvertebrates to mostly larval forms and emerging adults of insects such as caddisflies, true flies, mayflies, stoneflies, and the more mobile representatives of other invertebrate taxa, such as the amphipod *Hyalella azteca*. Since BFS will withdraw a low percentage of the river flow, the entrainment of macroinvertebrates is also expected to be a low percentage of those found in the river. Finally, as in the case for plankton, recruitment capabilities of macroinvertebrates should offset losses due to entrainment; for example, 300 to 1000 eggs may be produced per individual caddisfly,[48] and over 1000 eggs per female have been observed in stoneflies (*Taeniopteryx nivalis*).[49]

Entrainment of fish eggs and larvae may also be expected during fish spawning periods, primarily May through June. The amount of ichthyoplankton entrained will vary, but the staff believes it will be relatively low. First of all, the abundance of fish eggs and larvae collected by the applicant in the vicinity of the intake area was low (ER, Tables 2.2-122 and 0.2.45-3) and secondly, most spawning and larval development should occur in the backwater areas rather than in the main channel of the river. This is indicated by the ichthyoplankton collections performed by the applicant (ER, Table 2.2-122) and is inferred from information on preferred spawning habitats of the important fish species in the Verdigris (Appendix E, Table E.1). Another important consideration is that the ichthyoplankton (especially eggs) would not be found homogeneously mixed in the water column. Except for the gizzard shad, freshwater drum, and goldeye, the eggs of the important Verdigris River fish are basically demersal and/or adhesive (Appendix E, Table E.1), and would thus not be subject to entrainment. Also, the small losses should be compensated for by the relatively high fecundity of the fish species (see Appendix E, Table E.2). One female of some species is capable of producing several times more eggs than would be entrained in one day. Finally, turbulence, high turbidity, and paucity of food make chances of ichthyoplankton occurrence smaller in the main channel than in the backwater areas. The natural mortality of ichthyoplankton in the main channel could possibly approach 100%. For these reasons, the staff feels that ichthyoplankton entrainment will be of little consequence.

In summary, the staff concludes that losses due to entrainment should not seriously impact the Verdigris River ecosystem. However, since most major aquatic groups occur in patchy or zoned distribution patterns that change on diel, seasonal, and annual bases,[50] any given species or group will be less susceptible or more susceptible to entrainment than if distributed homogeneously in the water column. Because of the uncertainty over the actual distribution patterns of aquatic organisms in the Verdigris, the applicant has indicated that he will monitor entrainment losses to determine the quantities of planktonic organisms and benthic macroinvertebrates entrained, and to assess the importance of these losses (ER, p. 6.2-8).

Barrier to Biotic Passage

Because of the limited area influenced by intake velocity in relation to river width, the low velocity of intake flow, the mid-water depth of intake, and the shoreline location of the intake structure, neither the structure nor the effects of water intake should impose a barrier to passage by aquatic organisms. As indicated above, even some organisms, particularly fish, that come under the direct influence of the BFS water intake currents will be able to escape. The staff concludes that the intake structure will have minimal effect on biotic passage.

Impinged Debris

The only means provided for removal of impinged debris, including aquatic biota, from the intake screens is by backwashing. Potentially this could have a minor deleterious effect upon the river ecosystem if fish impingement becomes significant. It has been shown that the decomposition of large quantities of dead fish within a given area can increase the concentrations of ammonium and other toxic materials and can decrease dissolved oxygen levels.[51] Since fish impingement is expected to be low, and since some organisms, such as gar, eat dead fish,[52,53] the staff believes that the impact from backwashing intake screen debris will be negligible.

5.6.2.2 Discharge

Thermal Effluent

Wastewater effluent will be retained in a holding pond for at least 24 hours, and as a result, the $\Delta T$ between the wastewater discharged to the Verdigris and the ambient river water will be reduced. In fact, during summer months the plant effluent should be almost the same temperature as the ambient river water. The size of the thermal plume should also be small. Under extreme meteorological and hydrological conditions (high wet-bulb temperature and low ambient river temperature), the 5°F excess isotherm will extend only about 30 feet downstream and 24 feet into the river from the point of discharge, enclosing an area of 580 square feet. This conservatively estimated plume will be extremely small compared with the size of the mixing zone allowed by State standards (Sec. 5.3.2). Under normal operating conditions the plume will be much smaller.

Because of the extremely small thermal plume, surface discharge, unfavorable habitat, river turbulence and flow, and paucity of food organisms, the discharge area will not likely become an area of fish congregation. Furthermore, in the staff's opinion, the thermal effluent will not adversely impact the macrophyte community. Steep banks, maintenance dredging, high turbidity, waves, and scouring river flow already impose limitations on macrophyte development in the main channel. The thermal plume is expected to extend only a few feet below the surface and should not impact benthic communities.

Since the temperature differential will be slight and the area of the thermal plume small, there should be no major adverse thermal impacts on organisms that drift through the plume. The temperature differential and the duration of exposure to which Verdigris River organisms will be subjected are well within the reported tolerance limits of macroinvertebrates, zooplankton, and phytoplankton.[54-59]

Heat enrichment in the late winter and early spring should not influence the rate of succession of the phytoplankters at BFS.[60] Water temperatures within the mixing zone will not be raised to 10°C over ambient, and transient time through the small plume will be too short to trigger any significant microflora changes.

As mentioned in Section 5.6.2.1, the main channel provides poor habitat for ichthyoplankton (relative to backwater areas), and factors such as scouring flow make their chances of survival low. As a result, there is a low abundance of viable ichthyoplankton in the main channel of the river. Even those viable ichthyoplankton that will drift through the thermal plume should not be adversely affected. Studies at higher temperature differentials and longer durations of thermal gradient exposure than expected from the BFS discharge have shown no significant effects on developing fish eggs.[61,62] The staff concludes that the thermal effluent will have negligible impacts upon the Verdigris River ichthyoplankton.

Although non-lethal temperature changes have been shown to deleteriously affect fish populations, e.g., by lowering swimming performances[63] or by altering fish parasite population levels,[64] such problems are not expected to arise at BFS. The thermal differential will be small; the transient time through the plume will be short; fish will be able to avoid the discharge area; and since it is not a preferred habitat, the area is not expected to attract fish. These factors should preclude any acute short-term or chronic long-term deleterious impacts on Verdigris River fish populations.

Nickum[65] found that sudden temperature changes, even upwards to 20°F, rarely produce mortality of fishes in natural habitats, and furthermore concluded that most fish, perhaps all, can tolerate relatively large, sudden temperature changes as long as the lethal limits of temperature for each species are not exceeded. As the 24-hour minimum retention in the wastewater holding pond will effectively cool discharge water to near-ambient levels in summer, operation of BFS will not result in temperatures exceeding the upper thermal tolerance limits of fish.

Fish kills have been observed at power plants in winter because of "cold shock" experienced when generating units are turned off. These kills usually occur when there is a rapid, drastic temperature drop, e.g., 16.9 Celsius degrees in 30 minutes.[66] Impacts from "cold shock" at BFS should be negligible or non-existent for the following reasons: (a) the temperature differential prior to any plant shutdown in winter will be minimal (< 5.6 Celsius degrees at point of discharge); the effluent is first discharged to the wastewater holding pond, thus the temperature of water discharged to the river will drop to ambient river level gradually (minimum of 24 hours), (b) the thermal plume will not be an area of congregation for fish.

In summary, the staff concludes that impacts from the BFS thermal effluent will be minimal or non-existent.

Chemical Effluents

Assuming that the size and extent of the chemical plume* from the BFS discharge into the Verdigris will be similar to that of the thermal plume, drifting and swimming organisms will be exposed only briefly to abnormal concentrations of chemicals. (See Table 3.6 for chemical concentrations expected in the immediate vicinity of effluent outfall.)

Macroinvertebrates commonly encountered in stream drift and some benthic species that are less static in distribution and somewhat independent of benthic conditions[67] will come into contact with the chemical plume. However, only a small percentage of such organisms in the river are expected to be exposed, and exposure time will be so short that mortality should be negligible. Because of the small plume size, small temperature differential, and the various factors that make the area a non-attractive habitat, fish are not expected to congregate at the discharge area. Direct physical impacts (from suspended solids) and chemical impacts on fish populations should, for the most part, be minimal. The incidence of gas-bubble disease should be minimal or non-existent at BFS. The major factors that contribute to gas-bubble disease (high temperature changes, high flow, and deep discharges)[68] will not occur as a result of the design and operation of the BFS wastewater discharge system.

Established benthic communities in the immediate vicinity of the discharge should not be affected by the chemical effluents, since the plume will be limited to a depth of only a few feet.

There are uncertainties about the possible deleterious effects of the polyol-ester and/or phosphonate anti-scalants proposed for use at BFS. The compounds could have short-term acute and/or long-term chronic impacts on aquatic organisms. The adverse effects include: (1) possible buildup and release of available phosphates, causing adverse environmental impacts associated with increased rates of eutrophication, (2) direct (interference with gill efficiency) and indirect (increasing susceptibility to predation, parasitism, disease, etc.) effects to biota from increased colloidal and particulate releases to the river, and (3) inherent toxicities of the anti-scalants to indigenous biota.

Accelerated eutrophication and nuisance algal blooms can be caused by addition of decomposable organic compounds as well as by phosphorus and nitrogen.[69] The discharge of the phosphorus-containing anti-scalants at BFS will probably not cause eutrophication problems immediately downstream of BFS. Hynes[70] points out that most plant growth in rivers is planktonic, and nutrient additions that would ordinarily increase planktonic development are usually counteracted by turbidity increases that accompany nutrient inputs. In the main river channel at BFS, primary production is probably already limited by the high turbidity. Further downstream, however, there may be increased eutrophication due to the input of the phosphorus-containing compounds at BFS. Relatively large amounts of anti-scalants will be introduced to the river (5 to 10 ppm in the discharge, which will increase the amount of phosphorus in the river after complete mixing by 0.08 to 0.17 ppm during low flow in the summer). It is not known in what manner or how quickly the anti-scalants will break down into compounds that plants can utilize, but it is possible that downstream, especially in the backwater areas where turbidity is lower than in the main channel, plant growth will be increased.

There are also uncertainties about the potential adverse effects that could result from the use of acrylic acid-based anti-scalants, also proposed for possible use by the applicant.

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The effects of colloidal and particulate additions resulting from the use of the anti-scalants, as well as the inherent toxicities of these chemicals, are also unclear and of concern to the staff. The staff, therefore, will not approve the use of polyol-esters, phosphonates, acrylic acids, or other additives until the applicant can demonstrate to the staff's satisfaction that their use will not result in serious adverse environmental impacts. Staff approval will also be required for alternatives to the use of the proposed anti-scalants, including reduction in cycles of recirculation and increased use of sulfuric acid. Prior to issuance of an operating license, the applicant will be required to demonstrate to the satisfaction of the staff, the environmental acceptability of any anti-scalant chosen.

Although the chemical and thermal effluents acting alone are not expected to adversely affect the river biota (except possibly for the anti-scalants), there is a paucity of data concerning the tolerance of fish and other aquatic organisms to the combined effects of temperature and various chemicals associated with power plant operation.[71] The applicant has committed to monitor the aquatic community (ER, p. 6.2-8 and 6.2-9) in such a way as to determine waste heat and chemical stresses. If stresses occur, the staff will require that the applicant submit proposed mitigative measures for the staff's evaluation and approval.

Barrier to Biotic Passage

The predicted thermal mixing zone will meet the water quality standards for Oklahoma.[72] As a result, an extensive portion of the Verdigris River shall remain unaffected and thus serve as a zone of passage for fish and other mobile and drifting organisms.

## 5.7 OPERATION OF THE POWER TRANSMISSION SYSTEM

Operation of any high-voltage transmission line may be of concern in regard to shock hazards, electric field effects, acoustical and electrical noise, the production of ozone, and herbicide use during right-of-way maintenance.

The electric field associated with high-voltage transmission lines will induce voltages in conducting objects within the field. If the object is well grounded, the potential between the object and the ground will be near zero. If the object is insulated from the ground, significant voltages may be induced and a potential shock hazard created. Currents less than 6 mA are considered secondary or "let-go" currents and are not in themselves considered dangerous (the threshold of sensation is about 1 mA). Currents of 6 mA or larger are considered primary[73] currents, which can cause ventricular fibrillation. The value of the ground gradient to produce a current of about 1 mA is equal to or greater than 15 kV/m for the great majority of cases[74] and will depend in part on the height of the conductor above ground. The typical values of maximum gradients at ground level for 345-kV transmission lines (the highest voltage proposed for the BFS system) have been given as 5 kV/m for single-circuit lines.[74] Dangerous induced-shock currents are therefore not expected as a result of the operation of the BFS lines.

In Arkansas, there are numerous chicken barns, some of which are constructed as pole barns (metal roof and sides supported on wooden poles). It may not be feasible to route the lines completely away from these barns because all possible locations are not known at the present time (new barns can be built essentially in one day). Therefore, the staff will require that all chicken barns and all other metal buildings and fences under or near (within 0.1 km) the transmission lines be inspected for induced currents, measured from the barn to a temporary ground installed for the inspection. These inspections are to take place with the lines fully energized, and will include all new barns constructed during the life of the plant, within 30 days of the completion of the exterior barn construction, if such details are known to the applicant. If currents equal to or greater than 4 mA ("let go" current for a child) are detected, the staff will further require the applicant to install adequate grounding on the barns.

Radio interference, television interference, and audible noise can result from operation of high-voltage transmission lines because of corona effects[75] and poor construction and maintenance. The applicant intends to construct the 345-kV lines such that these effects are minimized (ER, Sec. 3.9.10.9, p. 3.9-63).

The effect of electric fields on humans working or living under or around EHV transmission lines has received much attention. A review of the work to date has been sponsored by the Electric Power Research Institute.[79] An excerpt from the final report (page 78) states:

"In summary, all of the American and West European test results on humans (except for Spain) at present field levels (less than about 20 kV/m) gave no indication of hazardous effects. Many of the European laboratory tests were conducted under very carefully controlled conditions which eliminated the possibility of unrecognized and overshadowing environmental factors such as low-frequency acoustical noise. The fact that the Soviets and Spanish researchers have not considered other environmental influences which could cause similar effects, such as low-frequency acoustical noise, and the fact that both the Soviet and West European research scientists have not been able to observe the reported switchyard worker symptoms in a significant way in tests conducted under carefully controlled laboratory conditions, support the view that factors other than the electric field as normally encountered were responsible for the observed symptoms."

While experimental work is still underway on the biological effects of ground level electric fields along EHV transmission lines, the weight of current evidence points to the conclusion that there are no significant biological effects attributable to the fields associated with such lines. The staff, therefore, concludes that there will be no significant adverse effects associated with the Black Fox plant transmission lines.

Ozone ($O_3$) can form in the air around the cylindrical conductors of high-voltage transmission lines, particularly during bad weather, due to ionization of the air molecules by corona discharge. Ozone also occurs naturally, produced mainly by ultraviolet radiation and lightning discharges, and is a major component of photochemical "smog." Ground-level ozone concentrations in areas distant from urban pollution generally range between 10 and 50 ppb (parts per billion). The Federal Environmental Protection Agency has established the national primary air-quality standard for such oxidants as 80 ppb by volume, maximum arithmetic mean, for a one-hour concentration not to be exceeded more than once per year.[76] Ozone is known to be injurious to vegetation and animals, including humans, when concentrations exceed 50 ppb for prolonged periods. However, recent studies[77,78] indicate that ozone levels produced by energized 765-kV power lines range from less than 1 ppb to less than 10 ppb in the vicinity of the conductors under various weather conditions. The levels would be considerably less in the vicinity of conductors carrying 345-kV as is proposed for the BFS transmission system. The staff therefore concludes that production of ozone by the BFS lines will not cause adverse impacts and will probably cause no measurable increase in ambient ozone levels in the vicinity of the lines.

## 5.8 ENVIRONMENTAL EFFECTS OF THE URANIUM FUEL CYCLE

On July 21, 1976, the United States Court of Appeals for the District of Columbia Circuit decided in Natural Resources Defense Council v. NRC that the NRC's final fuel cycle rule (39 FR 14188) was inadequately supported by the record insofar as it treated two aspects of the fuel cycle -- the impacts from reprocessing of spent fuel and radioactive waste management. The decision generally complimented other aspects of the Commission's survey underlying Table S-3.

In response to the Court decisions, the Commission issued a General Statement of Policy (41 FR 34707, August 16, 1976). In that statement, the Commission announced its intention to reopen rulemaking proceedings on the environmental effects of the fuel cycle to supplement the existing record with regard to reprocessing and waste management, to determine whether the rule should be amended, and if so, in what respect. The Commission directed the staff to prepare a well-documented supplement to WASH-1248 to establish a basis for identifying environmental impacts associated with fuel reprocessing and waste management activities that are attributable to the licensing of a model light water reactor (LWR). The NRC staff issued NUREG-0116, Environmental Survey of the Reprocessing and Waste Management Portions of the LWR Fuel Cycle in October 1976 for this purpose.

On November 5, 1976 the Commission issued a Supplemental General Statement of Policy regarding the licensing of nuclear power plants as related to the analysis of fuel cycle environmental impacts. The Commission concluded that licensing of light water reactors may be resumed on a conditional basis using existing Table S-3 values for reprocessing and waste management, provided the revised values presented in the Commission's notice of proposed rulemaking of October 18, 1976 were also examined to determine the effect on the cost-benefit balance for constructing or operating the plant.

In accordance with the proposed rule the staff has considered the revised values for reprocessing and waste management in its determination of effects on the cost-benefit balance as presented in the Draft Environmental Statement (DES) for BFS.

In the original fuel cycle rule, the environmental impacts for fuel cycle activities necessary for the support of an LWR were summarized in Table S-3 as shown in 10 CFR 51.20 and presented on page 5-37 of the Black Fox DES. Table 5.16 presents a summary of environmental considerations of the uranium fuel cycle as originally contained in Table S-3 together with the modifications given in the proposed rulemaking notice of October 18, 1976, and presented in NUREG-0116. Principal changes include those in the categories of land use, chemical effluents, iodine releases, Carbon-14 releases, and buried solids.

The following describes the difference between the impacts described in Table S-3 as it was originally promulgated in 10 CFR 50.21 and the impacts resulting from the revised assessment of reprocessing and waste management considerations in NUREG-0116.

The land commitment reflected in NUREG-0116 is slightly larger than that reflected in the original Table S-3. The original estimates were smaller by some 30 acres per reference reactor year in temporarily committed land and about 3 acres per year in permanently committed land for waste disposal. These revisions increase the temporary land commitment associated with the fuel cycle supporting the Black Fox facility over its projected 30-year operating life by some 1-1/2% of the approximately 2206 acres temporarily committed for operation of the facility itself. The total annual land requirement for the fuel cycle supporting a model 1000 MWe LWR is approximately 100 acres (94 acres temporarily committed and 7.1 acres permanently committed). Over the 30-year operating life of the plant this amounts to about 2100 acres,* which is approximately equal to the commitment for the Black Fox facility itself. Considering common classes of land use in the United States, the revised values do not constitute significant changes in the cost-benefit balance for the Black Fox facility.

To cast the land requirement into further perspective, the temporarily disturbed land associated with the fuel cycle supporting a model 1000 MWe LWR is comparable to the temporarily disturbed land associated with the fuel cycle supporting a small coal-fired power plant of about 100 MWe.

Hydrogen chloride has been included in NUREG-0116 as a gaseous chemical effluent, resulting from incineration of plastics in the waste management systems. The amount is a small fraction of other acid gas effluents from the fuel cycle discussed in both Table S-3 and NUREG-0116. No significant impact is attributable to the change. Most of the other changes under the heading of chemical effluents have been revisions downward.

Radioactive effluents released to the environment estimated to result from the reprocessing and waste management activities or other phases of the fuel cycle process are set forth in Table S-3. Based on these effluents, the overall gaseous dose commitment to the U.S. population from the fuel cycle for a 1000 MWe reference reactor would be approximately 250 man-rem per year. This is approximately .001% of the average natural background dose of approximately 21,000,000 man-rem** to the U.S. population. The additional dose commitment to the U.S. population from radioactive liquid effluents due to fuel cycle operations would be approximately 260 man-rem per year for a 1000 MWe reference reactor. The combined dose commitment, therefore, would be about 510 man-rem annually.

There have been increases in NUREG-0116 in the estimated Carbon-14, Iodine and Tritium release rates. However, the principal addition in radioactive gaseous effluents is the dose estimate of 110 man-rem for the release of Carbon-14. These additional releases together will add some 150 man-rem to the gaseous U.S. dose commitment of 250 man-rem as determined using Table S-3.

The total gaseous and liquid involuntary dose commitment to the U.S. population will, however, remain comparable to the 510 man-rem dose evaluated using Table S-3, since the liquid source terms (particularly for Tritium) have been revised downward.

The substitution of a "throw-away" cycle would increase the dose commitment accumulated to the year 2000 for the reprocessing and waste management portions of the fuel cycle. This is due principally to increased occupational exposure during fuel storage. These effects amount to some 12,000 man-rem total to the year 2000 and would have only a small effect on overall population dose commitment.***

*The temporarily committed land at the reprocessing plant is not prorated over 30 years, since the complete temporary impact accrues regardless of whether the plant services one reactor for one year or 57 reactors for 30 years. (See footnote "h" to Table 2.10.)

**Based upon a natural background dose rate of 100 mrem/yr.

***As a result of increased requirements for new source material due to a "throw away" cycle, estimated releases from mining and milling would be increased. This, in turn, would increase the estimated dose commitment for the total fuel cycle by some 600 man-rem per reference reactor year. Although this is larger than the dose commitment due to other elements of the fuel cycle, it is still small compared to the natural background exposure level of some 21,000,000 man-rem per year.

Table 5.16 Summary of Environmental Considerations For Uranium Fuel Cycle Normalized to Model LWR Reference Reactor Year[a]

| Natural Resource Use | Total WASH-1248[b] | Total NUREG-0116[c] |
|---|---|---|
| Land (Acres) | | |
| Temporarily Committed | 63 | 94 |
| Undisturbed Area | 45 | 73 |
| Disturbed Area | 18 | 22 |
| Permanently Committed | 4.6 | 7.1 |
| Overburden Moved (million of MT) | 2.7 | 2.8 |
| Water (millions of gal.) | | |
| Discharged to air | 156 | 159 |
| Discharged to water bodies | 11,040 | 11,090 |
| Discharged to ground | 123 | 124 |
| Total Water | 11,319 | 11,373 |
| Fossil Fuel | | |
| Electrical energy (thousand MW-hr.) | 317 | 321 |
| Equivalent coal (thousand MT) | 115 | 117 |
| Natural Gas (million scf) | 92 | 124 |
| Effluents | | |
| Chemical (MT) | | |
| Gases (MT) | | |
| $SO_x$ | 4,400 | 4,400 |
| $NO_x$ | 1,177 | 1,190 |
| Hydrocarbons | 13.5 | 14 |
| CO | 28.7 | 29.6 |
| Particulates | 1,156 | 1,154 |
| Other Gases | | |
| $F^-$ | 0.72 | 0.67 |
| HCl | - | 0.14 |
| Liquids | | |
| $SO_4^=$ | 10.3 | 9.9 |
| $NO_3^-$ | 26.7 | 25.8 |
| Fluoride | 12.9 | 12.9 |
| $Ca^{++}$ | 5.4 | 5.4 |
| $Cl^-$ | 8.6 | 8.5 |

718 300

Table 5.16 (continued)

| Natural Resource Use | Total WASH-1248[b] | NUREG-0116[c] |
|---|---|---|
| Effluents (cont'd.) | | |
| NA$^+$ | 16.9 | 12.1 |
| $NH_3$ | 11.5 | 10.0 |
| Tailings Solutions (thousands) | 240 | 240 |
| Fe | 0.4 | 0.4 |
| Solids | 91,000 | 91,000 |
| Radiological (curies) | | |
| Gases (including entrainment) | | |
| Rn-222 | 74.5 | 74.5 |
| Ra-226 | 0.02 | 0.02 |
| Th-230 | 0.02 | 0.02 |
| Uranium | 0.032 | 0.034 |
| Tritium (thousands) | 16.7 | 18.1 |
| Kr-85 (thousands) | 350 | 400 |
| I-129 | 0.0024 | 1.3 |
| I-131 | 0.024 | 0.83 |
| Fission Products | 1.0 | 0.021 |
| Transuranics | 0.004 | 0.024 |
| C-14 | - | 24 |
| Liquids | | |
| Uranium & Daughters | 2.1 | 2.1 |
| Fission & Activation Products | - | 5.9E-6 |
| Ra-226 | 0.0034 | 0.0034 |
| Th-230 | 0.0015 | 0.0015 |
| Th-234 | 0.01 | 0.01 |
| Tritium (thousands) | 2.5 | - |
| Ru-106 | 0.15 | - |
| Solids (buried onsite)[d] | | |
| Other than high level (shallow) | 601 | 5,300 |
| Transuranic and high level wastes (deep) | - | 1.1E+7 |
| Thermal (billions of Btu) | 3,360 | 3,462 |
| Transportation (man-rems) | | |
| Exposure of workers and general public | 0.334 | 2.46 |

[a]Reference Reactor Year (RRY) is a 1000 MWe reactor operating at 80% of its maximum capacity for one year. An RRY is equivalent to an Annual Fuel Requirement as used in WASH-1248 dated April 1974.

[b]Table S-3 values.

[c]Revised Table S-3 values (set forth in Table 2.10).

[d]Not released to the environment.

SOURCES: Environmental Survey of the Reprocessing and Waste Management Portions of the LWR Fuel Cycle, NUREG-0116, October 1976.

Environmental Survey of the Uranium Fuel Cycle, WASH-1248, April 1974.

There is an increase to the transportation dose commitment presented in Table S-3. The revised transportation dose value of some 2.5 man-rem is based upon refined calculational assumptions and modeling techniques. This dose is not considered significant in comparison to the natural background.

There has been an increase in the quantity of buried radioactive waste material (both high level and transuranic): These wastes are placed in geosphere and are not released to the biosphere and no radiological environmental impact is expected from such disposal. Table S-3 did not include either the disposal of high level or transuranic wastes nor low level wastes from reactors which were buried.

In accordance with the Commission's directive contained in the Supplemental General Statement of Policy, the staff has assessed, as set forth above, the effect of using the revised chemical processing and waste storage values set forth in the Commission's Notice of Proposed Rulemaking of October 18, 1976, on the cost-benefit balance for the Black Fox facility. These impacts, as discussed above, are so small that there is no significant change in impact from that associated with the effects presented in Table S-3 and, accordingly, the use of the revised values would not tilt the cost-benefit balance against issuance of the license.

## 5.9 IMPACTS ON THE COMMUNITY

The applicant predicts that the size of the annual average operating crew will stabilize at 136 people beginning in 1985 (Table 4.3) and assumes that 10% of the crew will be new residents in the region. The applicant further estimates that up to the year 1990, 5% of the crew will live within five miles of the site; after then the percentage is expected to increase.

Assuming that each resident worker will create 0.56 additional jobs, the total local personal income, including multiplier effects, will be $225,000 (current dollars) in 1985 (ER, Tables 8.1-19 and 8.2-24). However, the staff believes that the magnitude of the income multipliers will vary widely, depending upon the workers' settlement patterns and upon their shopping habits. On the one hand, the proximity of Tulsa will result in a substantial "leakage" effect (expenditure of money in the larger city instead of in the community of residence); while on the other hand, more immigrating workers may settle within five miles of the site than has been predicted by the applicant.

Ground fog induced by the proposed cooling towers will occasionally occur at the junction of State Highways 33 and 88, and along a 1.5-mile section of Highway 88. This will be perceived negatively by some travelers using the road, and by involved branches of governmental agencies. The noise and other esthetic and perceived impacts caused by the BFS will, to some extent, affect the activities of some residents and potential users of recreational areas, especially in the near vicinity of the site. This, however, may not be greater than that resulting from the placement of any large industrial facility in a rural area.

On the positive side, the staff believes that the impacts of the plant could be potentially beneficial for the economic growth of the communities in the vicinity of the BFS.

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# 6. ENVIRONMENTAL MEASUREMENTS AND MONITORING PROGRAMS

## 6.1 PREOPERATIONAL

### 6.1.1 Thermal

Temperatures of the Verdigris River water were measured during four periods between August and December 1974 near the station intake and during 11 periods between February and December 1974 near the station discharge. The data can be found in the ER, Appendix 2B. The temperatures were recorded by thermistors (YSI Model 54). The results of these measurements all lie within the range of values reported at the Newt Graham Lock and Dam (see Table 5.2).

### 6.1.2 Radiological

The applicant has proposed an offsite preoperational radiological monitoring program to provide for measurement of background radiation levels and radioactivity in the plant environs. The preoperational program, which provides a necessary basis for the operational radiological monitoring program, will also permit the applicant to train personnel and evaluate procedures, equipment, and techniques, as indicated in Regulatory Guide 4.1.

A description of the applicant's proposed program is summarized in Tables 6.1 and 6.2. More detailed information on the applicant's radiological monitoring program is presented in Section 6.1 of the ER. The applicant proposes to initiate the program no later than two years prior to operation of the plant.

The staff concludes that the preoperational monitoring program proposed by the applicant is acceptable.

### 6.1.3 Hydrological

The preoperational hydrological monitoring program has been developed by the applicant to assess the physical, chemical, and biological parameters of the site area surface waters and is discussed in detail in the ER, Section 6.1.1. The locations of the aquatic sampling stations are shown in Figure 6.1. Table 6.3 summarizes the parameters to be measured and the sampling frequency at these locations.

Onsite groundwater monitoring has been limited to the observation of fluctuations in groundwater level and to conducting permeability and percolation tests. Because data are available in the literature, no additional groundwater quality measurements have been made by the applicant.

The staff will consider the applicant's hydrological monitoring program adequate when expanded to include the following staff requirements:

1. The applicant shall establish a new sampling station, 2a (Fig. 6.1), to be maintained and sampled contemporaneously with Station 2 for the duration of construction of the barge slip, intake, and discharge structures.
2. The applicant shall establish an additional water monitoring station at the outlet of the diked spoils area along the Verdigris River to be maintained until the spoils have been stabilized.

### 6.1.4 Meteorological

In November 1973, an instrumented 330-foot-high tower began operating onsite (PSAR). The tower is approximately 2500 feet east of the proposed plant structures. Three levels on the tower were instrumented as shown in Table 6.4, while on the ground nearby, precipitation amounts, visibility, and atmospheric pressure were determined.

The parameters measured by the various instruments were recorded both on analog strip charts for comparison purposes and in digital form on magnetic tape, which was used in preparing summary tabulations of data as well as joint frequency distributions of wind speed and direction by atmospheric stability class. During the one-year period December 1973-November 1974, overall data recovery was better than 96%.

Table 6.1. Environmental Radiological Monitoring Criteria--Sample Locations

| Sample Type | Number of Samples and General Locations | Specific Locations | Comments |
|---|---|---|---|
| I. Air particulates | 1. 3 samples from locations (in different sectors) of the highest offsite ground-level concentrations | a) On NNW Site boundary<br>b) On N Site boundary<br>c) On NW Site boundary<br>d) On WNW Site boundary | |
| | 2. 1 sample from the residence having the highest $\chi/Q$ as well as each of 1-3 communities within a 10-mile radius of facility | a) The residence nearest the site in the NNW sector<br>b) Inola--3 miles NE<br>c) New Tulsa--8 miles WSW<br>d) Fair Oaks--9 miles WNW | |
| | | e) Tiawah--10 miles N | Optional but included since it is directly north of the site in the prevailing wind direction. |
| | 3. 2 samples from control locations (10-20 miles distant and in the least prevalent wind direction) | a) Pryor--19 miles northeast of the site<br>b) Another convenient location 15 to 20 miles from site in the ENE sector. | Pryor is northeast of the site and is the community with the lowest $\chi/Q$ value at that distance. Control locations are for background purposes. |
| II. Air iodine | 1. 2 samples from locations (in different sectors) having the highest offsite ground-level concentrations | a) Same as I, 1, a and b above | |
| | 2. 1 sample from the residence having the highest $\chi/Q$ as well as 1 community within a 10-mile radius of the facility | b) Same as I, 2, a and b above | |
| | 3. 1 sample from a control location (10-20 miles distant and in the least prevalent wind direction) | c) Same as I, 3, a above | |

Table 6.1. Continued

| Sample Type | Number of Samples and General Locations | Specific Locations | Comments |
|---|---|---|---|
| III. Soil | 1. Samples from the same locations as for air particulates plus 5 additional locations | a) Same as all locations for I, 1, 2, 3, above<br>b) The 5 additional locations will be design inputs | Acceptable programs may be found in HASL-300[a] or Regulatory Guide 4.5. |
| IV. Direct radiation | 1. 2 or more dosimeters to be placed at the same locations as for air particulates, as well as 2 additional control locations (selected on a basis similar to the 2 air sample control locations) | a) Same as all locations for I, 1, 2, 3 above<br>b) The two additional control locations will be design inputs | |
| | 2. 2 or more dosimeters to be placed at each of 3 other locations (different sectors) of highest calculated offsite ground-level dose | a) These will be design inputs | |
| V. Water | | | |
| A) Surface | 1. 1 sample upstream | a) Between 0.5 and 1.0 miles upstream of the BFS discharge outfall on the Verdigris River | |
| | 2. 1 sample in immediate area of discharge | a) Immediate area of discharge | |
| B) Ground | 1. 1 or 2 samples from sources most likely to be affected | a) These locations will be design inputs | |
| | 2. 1 sample from groundwater source upgradient | a) This location will be a design input | |
| C) Drinking Supply | 1. 1 sample for each of 1 to 3 supplies obtained within 10 miles of the facility which could be affected by its discharge or the first supply within 100 miles if none exists within 10 miles | a) Intake structure of the Broken Arrow water treatment plant | |
| VI. Aquatic samples | | | |
| A) Sediment & indicator organisms | 1. 1 sample upstream from discharge point | a) 0.5 mile upstream of outfall | |
| | 2. 1 sample in immediate downstream area of discharge point | a) Directly downstream of outfall | |

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Table 6.1. Continued

| Sample Type | Number of Samples and General Locations | Specific Locations | Comments |
|---|---|---|---|
| VI. Aquatic samples (cont'd) | | | |
| A) Sediment & indicator organisms | 3. 1 sample at downstream impoundment | a) Newt Graham Lock and Dam No. 18 | |
| B) Sediment from shoreline | 1. 1 sample from downstream area with existing or potential recreational value | a) Channel View Public Use Area No. 2 | |
| VII. Milk | 1. 1 sample at the offsite dairy farm or individual milk animal site at the location having the highest $\chi/Q$ | a) Will be determined at the time the preoperational monitoring program will be started | Dairy farm or milk animal locations may change prior to initiation of the preoperational program |
| | 2. 1 sample from milking animals in each of 3 areas where doses are calculated to be greater than 1 mrem per year | a) Will be determined at the time the preoperational monitoring program will be started | |
| | 3. 1 sample from milking animals at a control location (10-20 miles distant and in the least prevalent wind direction) | a) From the general area of Pryor | |
| VIII. Fish | 1. 1 sample of each white crappie and flathead catfish in vicinity of discharge point | a) At the vicinity of the outfall | |
| | 2. 1 sample of same species in areas not influenced by station discharge | a) 2 miles upstream from Highway 33 bridge on Verdigris River | |
| IX. Fruits and vegetables | 1. 1 sample of each principal food product grown near the point having the highest $\chi/Q$ and from any area which is irrigated by water in which liquid plant wastes have been discharged | a) To be determined when the preoperational program is about to start | |
| | 2. 1 sample of green leafy vegetables at private gardens and/or farms in the immediate area of the station | a) To be determined when the preoperational monitoring program will be started | When green leafy vegetable from private gardens are not accessible, use nonedible plants with similar leaf characteristics from the same areas. |

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Table 6.1. Continued

| | Sample Type | | Number of Samples and General Locations | | Specific Locations | Comments |
|---|---|---|---|---|---|---|
| IX. | Fruits and vegetables (cont'd) | 3. | 1 sample of each of the same foods grown 10-20 miles distant in the least prevalent wind direction | a) | From the general area near Pryor | |
| X. | Meat and poultry | 1. | 1 sample or more of meat, poultry, and eggs from animals fed on crops within 10 miles of the station at the prevailing downwind direction or where drinking water is supplied from a downstream source | a) | To be determined when pre-operational program is about to start | Feedstuff and forage may be substituted for meat and poultry. |
| | | 2. | 1 sample of each of the same foods produced at locations 10-20 miles distant in the least prevalent wind direction | a) | From the general area near Pryor | |
| | | 3. | 1 sample each of bobwhite quail and cottontail rabbit in areas where these provide an important source of dietary protein | a) | From an area within a 10-mile radius of the site | To be taken only during open hunting season. |

[a]HASL-300, HASL Procedures Manual, J. H. Harley, Ed., Rev. August 1974.

Table 6.2. Environmental Radiological Monitoring Criteria--Sampling and Analysis

| Sample Type | Collection Frequency | Type and Frequency of Analysis | Comments |
|---|---|---|---|
| Air particulates | Continuous sampler operation with sample collection weekly or as required by dust loading, whichever is more frequent | Gross beta radioactivity following filter change, composite (by location) for gamma isotopic and composite Sr-89, -90 analyses quarterly | Particulate sample filters should be analyzed for gross beta 24 hours after sampling to allow for radon and thoron decay. Gamma isotopic analysis should be performed on individual samples if gross beta activity is 10 times greater than the mean of control samples. |
| Radioiodine | Continuous sampler operation with canister collection weekly | Analyze weekly for I-131 | |
| Soil | Once per 3 years | Gamma isotopic, Sr-90 on collection | |
| Direct radiation | Quarterly | Gamma dose quarterly | |
| Water samples | | | |
| Surface | Composite sample | Gamma isotopic analysis monthly; composite for tritium and Sr-89, -90 analyses quarterly | For composite samples collection aliquot time intervals should be short compared with compositing period. |
| Ground | Quarterly | Gamma isotopic and tritium analyses quarterly | To be sampled only when source is used for drinking or irrigation purposes in areas where the hydraulic gradient or recharge properties are suitable for contamination. |
| Drinking | Composite sample | Radioiodine analysis semimonthly. Gross β and gamma isotopic analyses monthly. Composite for tritium and Sr-89, -90 analyses quarterly | |
| Aquatic bottom sediments and organisms | Semiannually | Gamma isotopic, Sr-89 (except for sediments) and Sr-90 analyses semi-annually | |
| Sediment from shoreline | Semiannually | Gamma isotopic and Sr-90 analyses semiannually | |

Table 6.2. Continued

| Sample Type | Collection Frequency | Type and Frequency of Analysis | Comments |
|---|---|---|---|
| Milk | Weekly or semimonthly depending on calculated dose | Gamma isotopic and Sr-89, -90 analyses monthly | Weekly, when calculated dose to a child's thyroid exceeds 15 mrem/yr/unit; semi-monthly when the dose ≤ 15 mrem/yr/unit. |
| | | Radioiodine analysis weekly or semi-monthly when animals are on pasture | |
| Fish | Semiannually or in season | Gamma isotopic analysis on edible portions | |
| Fruits and vegetables | At time of harvest | Gamma isotopic analysis on edible portion. Radioiodine analysis on green leafy vegetables | |
| Meat and poultry | Semiannually | Gamma isotopic analysis on edible portions | |

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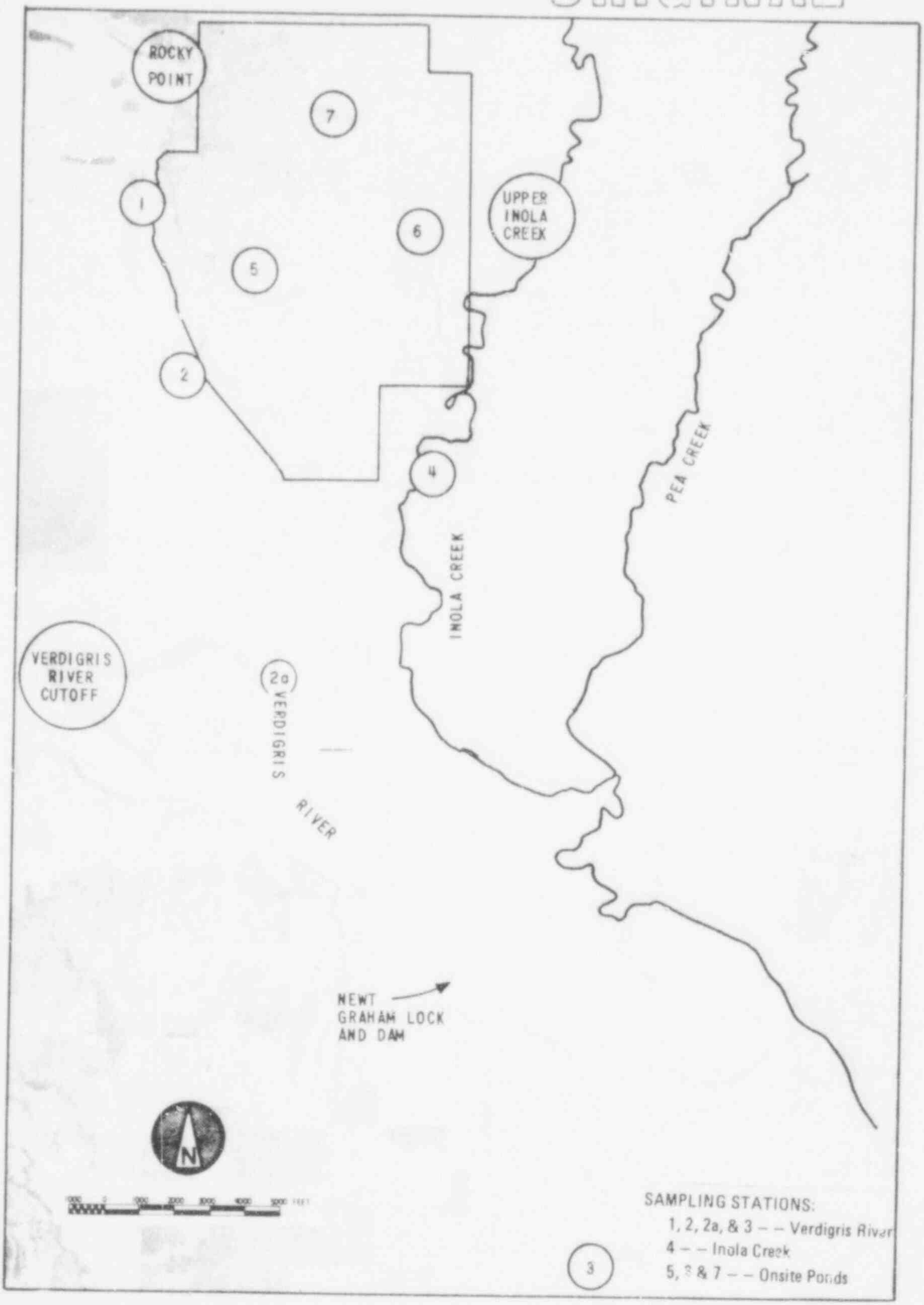


Fig. 6.1. Locations of Aquatic Stations Sampled during 1974. Modified from ER, Fig. 6.1-1.

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Table 6.3. Summary BFS Water Sampling Program

| Parameter | Location[a] and Frequency[b] | | | | |
|---|---|---|---|---|---|
| | 1,2,3 | 4 | 5 | 6 | 7 |
| Chemical oxygen demand (COD) | A | A | C | C | N |
| Calcium | A | A | B | B | B |
| Magnesium | A | A | B | B | B |
| Sodium | A | A | B | B | B |
| Potassium | A | A | B | B | B |
| Alkalinity (OH, $CO_3$, $HCO_3$) | A | A | A | A | A |
| Dissolved solids | A | A | B | B | B |
| Suspended solids | A | A | B | B | B |
| Nitrogen | | | | | |
| Total | A | A | A | A | A |
| Organic | A | A | A | A | A |
| Nitrite | A | A | A | A | A |
| Temperature | A | A | A | A | A |
| pH | A | A | A | A | A |
| Dissolved oxygen | A | A | A | A | A |
| Depth | A | A | A | C | C |
| Floating debris, ice cover, odor | A | A | A | A | A |
| Transparency | A | A | A | A | A |
| Turbidity | A | A | A | A | A |
| Specific conductance | A | A | A | A | A |
| Biochemical oxygen demand ($BOD_5$) | A | A | N | N | N |
| Nitrate | A | A | A | A | A |
| Ammonia | A | A | A | A | A |
| Phosphate | A | A | A | A | A |
| Chloride | A | A | A | A | A |
| Sulfate | A | A | B | B | B |
| Fluoride | A | A | B | B | B |
| Silica, dissolved | A | A | B | B | B |
| Chlorinated hydrocarbons (pesticides) | C | C | C | C | C |
| Total organic carbon | C | C | C | C | C |
| Bacteria | | | | | |
| Total coliform | A | A | C | C | C |
| Fecal coliform | A | A | C | C | C |
| Fecal streptococci | A | A | C | C | C |
| Trace element scan | C | C | C | N | C |
| Selected metals[c] | C | C | C | N | C |

From ER, Table 6.1-3.

[a]Location numbers refer to sampling stations shown in Figure 6.1.

[b]Sampling frequency: A = monthly; B = every other month; C = in one or more selected periods; N = not measured.

[c]Selected trace metals = Cu, Fe, Zn, Pb, Cd, Mn, Sr, Hg, Ba in August, and Fe, Mn, and Hg in October.

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Joint frequency data from the 33 foot level of the onsite meteorological tower was used in the determination of relative concentration ($\chi/Q$) and deposition (D/Q) values for evaluating dispersion conditions expected at the site both from elevated and near-ground-level releases.

The evaluation of the gaseous releases was in accordance with methods identified in Regulatory Guide 1.111.[1] In addition to continuous release modes, the periodic releases identified were evaluated as to their relative concentrations and deposition contributions assuming elevated sources.

### 6.1.5 Ecological

#### 6.1.5.1 Terrestrial

The applicant has proposed no preoperational nor construction monitoring programs for terrestrial ecology (ER, Sec. 6.1.4.3) except for the baseline surveys that are already completed and that served as a basis for the descriptive ecology of the site (ER, Sec. 2.2).

As described in Section 4.1.1, an inspection program for erosion in the draw between the central station complex and the wastewater holding pond will be required as a part of the preoperational monitoring program.

Table 6.4. Tower Instrumentation

| Height, feet | Measurement |
|---|---|
| 33 | Wind speed, wind direction, temperature, delta temperature, relative humidity. |
| 133 | Wind speed, wind direction, delta temperature. |
| 320 | Wind speed, wind direction, delta temperature. |

#### 6.1.5.2 Aquatic

During 1974 and portions of 1975, the biota of the Verdigris River, Inola Creek, and the farm pond systems were sampled, identified, and counted according to the schedule in ER Table 6.1-1 (does not include March-July 1975 ichthyoplankton sampling). Aquatic macrophytes, periphyton, phytoplankton, zooplankton, benthic macroinvertebrates, fish, fish eggs, and fish larvae were investigated. The methods are described in the ER, pp. 6.1-3 through 6.1-17, 6.1-37 through 6.1-48, and 6.2-7 through 6.2-9.

Aquatic Macrophyte Vegetation

Special attention was devoted by the applicant to pond macrophyte species since many farm ponds on the site supported extensive vegetative growth. Macrophytes were scarce or absent in the Verdigris River and Inola Creek. Biomass analyses were performed for duplicate one-square-meter quadrats at Stations 5 and 6 during March and June, and at Station 7 during July (ER, Fig. 2.1). All vegetation, including living roots, was harvested from each quadrat. Plants were sorted according to species and ash-free dry weighed.

Periphyton

Periphyton were collected on artificial substrata made of Plexiglas each month from March through October in 1974, and in January 1975, as outlined in the ER, Table 6.1-1. The plant material was identified and counted, and biomass and chlorophyll A determinations were performed.

Phytoplankton

Sampling was carried out as outlined in ER Table 6.1-1 and was concentrated in the summer months when algal communities normally undergo their most rapid changes. Samples were taken in duplicate at all aquatic stations, each sample consisting of a subsample from a composite water sample representing all depths. Composite grab samples were taken in instances when extremely shallow conditions precluded the normal compositing procedure. Identification and density, biovolume and diversity determinations were made.

## Zooplankton

Zooplankton samples were collected at all aquatic stations according to the schedule presented in ER Table 6.1-1. Duplicate samples were collected from the Verdigris River with a Clarke-Bumpus sampler (mesh number 20, 75 μm) towed from a boat for five minutes. Some samples were obtained via oblique hauls from near bottom to the surface. Samples were collected from Inola Creek and the farm pond stations by pouring a 35- to 100-liter composite depth water sample through a number 20 plankton net. The composited sample volume was the same for the four stations on any one sampling date. Duplicate samples were collected at each station. Subsamples were examined in a calibrated Sedgewick-Rafter (S-R) counting chamber. Species were identified, density was estimated, and diversity indices were determined.

## Benthic Macroinvertebrates

Quantitative benthic macroinvertebrate samples were collected according to the schedule presented in ER Table 6.1-1. In the Verdigris River at Stations 1, 2, and 3, a modified Hester-Dendy multiplate artificial substrate was employed. Hester-Dendy samples were also used at Station 4 on Inola Creek. In the three farm ponds (Stations 5, 6, and 7) and Inola Creek (Station 4) quantitative collections were made with a 15.2-cm-square Ekman dredge.

Qualitative samples were taken to obtain information on uncommon organisms that may not have been collected by quantitative means and to provide sufficient numbers of undamaged specimens for identification of common species. Qualitative collections were obtained with a Turtox delta-frame dip net (20 meshes/inch). Sediments were scooped and sieved in several areas at Stations 4, 5, 6 and 7.

Identifications, densities, and diversity values were made on all quantitative samples. Biomass ($mg/m^2$) was also determined for those organisms which constituted 5% or greater relative abundance on multiplate samplers.

## Fish

Fish were sampled at all aquatic stations as indicated in ER Table 6.1-1. To obtain a reasonably complete inventory of Verdigris River fish species, locations other than specific aquatic stations were qualitatively sampled. Collections were made in backwater and main channel areas of the Verdigris River both upstream and downstream of Newt Graham Lock and Dam. Most collecting was accomplished with three basic fishing techniques: electrofishing, seining, and special netting. Other specialized procedures were employed to improve the possibility of detecting rare species that might occur in the area. A summary of methods and applications is presented in the ER, Table 6.1-5; fish sampling locations are depicted in Figure 2.16, and discussed in the ER on pages 6.1-12 through 6.1-17.

Each fish collected was identified to species, weighed to the nearest gram (to the nearest ounce for fish over 1000 grams), and measured to the nearest millimeter (total length). Scale samples were taken from most individuals captured in the Verdigris River, and selected scales were sent to the Oklahoma Cooperative Fishery Research Unit at Oklahoma State University in Stillwater for further analysis. Age classifications, growth increments, length-weight regression equations, and various coefficients of condition were determined. Species diversity of each aquatic system (river, creek, and pond) was calculated for all identified taxa captured by all techniques during each sampling period.

## Fish Eggs and Larvae

Fish eggs and larvae (ichthyoplankton) were collected from Verdigris Stations 1, 2, and 3 during May, June, July, and August 1974. In addition, selected Verdigris River backwater areas were sampled during 1974 for comparison with the main channel. Sampling was identical to that described for zooplankton, except a No. 2 mesh (363 μm) net was used on the Clarke-Bumpus sampler. Extended oblique tows of 15 minutes or longer were made so that a volume of at least five cubic meters (5000 liters) was sampled. In some samples, the minimum volume could not be obtained because the high concentration of suspended solids clogged the net. Duplicate samples were taken at each location and occasionally some additional tows were made.

Ichthyoplankton in the Verdigris River in the area of the proposed water intake structure (Station 1) were collected monthly during the 1975 spawning season (February through July). Because of the low numbers of fish eggs and larvae that were observed during 1974, greater volumes of water were sampled. The sampling for 1975 employed 0.5-m-diameter nets (No. 2 mesh) equipped with calibrated flow meters. Nets were immersed until a minimum of 50,000 gallons (189 $m^3$) was sampled. Samples were taken three times during the sampling day from near the top and middle of the water column. If adequate flow did not exist for accurate operation of the flow meter, the nets were towed. During February through July 1975, at least 334,000 gallons of water were sampled during each sampling period.

Other Investigations

Trace metal analyses for water, macrophytes, and fish, and pesticide analyses for macrophytes were performed according to the schedule in ER Table 6.1-1 and methods described in the ER (pp. 6.1-16 and 6.1-17).

Conclusions

The staff finds that the applicant's aquatic preoperational monitoring program is adequate to provide baseline data against which to measure future operational impacts. Further preoperational monitoring will not be necessary. The staff recommends that the operational monitoring program be conducted in such a manner that valid comparisons can be made between preoperational and operational data.

### 6.1.6 Chemical

The baseline phase of the applicant's water quality monitoring program began in February 1974 and ended in January 1975. Samples were collected at regular intervals (monthly or less) from the sampling stations on the Verdigris River, Inola Creek and three onsite ponds. All samples were analyzed for 30 parameters listed in ER, Table 6.1-3.

Extensive State (Oklahoma Water Resources Board), and Federal (USGS) monitoring programs are being carried out at Newt Graham Lock and Dam, four miles downstream from the plant site. Only minor side streams or other perturbations occur in this stretch, and while minor differences in water quality can occur, the Federal, State, and applicant's monitoring programs should be generally adequate to provide baseline data that will assist in verifying the effects of construction and operation of the plant. However, the staff will require that the applicant's program be expanded with respect to construction monitoring as indicated in Section 6.1.3.

## 6.2 OPERATIONAL MONITORING

### 6.2.1 Ecological

The applicant has briefly discussed plans for an operational monitoring program (ER, Sec. 6.2), and this has been reviewed by the staff. In addition to the plans set forth by the applicant, the staff will require a fish impingement monitoring program. Since impingement potential is anticipated to be low (see ES Appendix D), only a general one to two year monitoring program involving counts of various species impinged will be required. Since the present action pertains to issuance of construction permits, staff discussion of the operational monitoring program is brief (see Section 5). A more detailed review of the required fish impingement monitoring program will be performed at the time of application for an operating license. Impingement monitoring will be included in the environmental technical specifications which are a part of an operating license.

### 6.2.2 Radiological

The operational offsite radiological monitoring program is conducted to measure radiation levels and radioactivity in the plant environs. It assists and provides backup support to the detailed effluent monitoring (as recommended by Regulatory Guide 1.21) which is needed to evaluate individual and population exposure and verify projected or anticipated radioactivity concentrations.

The applicant plans essentially to continue the proposed preoperational program during the operating period. However, refinements will be made in the program to reflect changes in land use or preoperational monitoring experience.

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An evaluation of the applicant's proposed operational mointoring program will be performed during the operating license review, and the details of the required monitoring program will be incorporated into the Environmental Technical Specifications for the operating license. NRC Regulatory Guide 4.8 also provides detailed information on operational programs for nuclear power plants.

Reference

1. "Draft Regulatory Guide 1.111," U. S. Nuclear Regulatory Commission, Washington, D. C., 1975.

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# 7. ENVIRONMENTAL IMPACT OF POSTULATED ACCIDENTS INVOLVING RADIOACTIVE MATERIALS

## 7.1 PLANT ACCIDENTS

A high degree of protection against the occurrence of postulated accidents in the Black Fox Station Units 1 and 2 is provided through correct design, manufacture, and operation, and the quality assurance program used to establish the necessary high integrity of the reactor system, as will be considered in the Commission's Safety Evaluation. Deviations that may occur are handled by protective systems to place and hold the plant in a safe condition. Notwithstanding this, the conservative postulate is made that serious accidents might occur, even though they may be extremely unlikely; and engineered safety features are installed to mitigate the consequences of those postulated events which are judged credible.

The probability of occurrence of accidents and the spectrum of their consequences to be considered from an environmental effects standpoint have been analyzed using best estimates of probabilities and realistic fission product release and transport assumptions. For site evaluation in the Commission's safety review, extremely conservative assumptions are used for the purpose of comparing calculated doses resulting from a hypothetical release of fission products from the fuel against the 10 CFR Part 100 siting guidelines. Realistically computed doses that would be received by the population and environment from the accidents which are postulated would be significantly less than those to be presented in the Safety Evaluation.

The Commission issued guidance to applicants on September 1, 1971, requiring the consideration of a spectrum of accidents with assumptions as realistic as the state of knowledge permits. The applicant's response was contained in the Environmental Report.

The applicant's report has been evaluated, using the standard accident assumptions and guidance issued as a proposed amendment to Appendix D of 10 CFR Part 50 by the Commission on December 1, 1971. Nine classes of postulated accidents and occurrences ranging in severity from trivial to very serious were identified by the Commission. In general, accidents in the high potential consequence end of the spectrum have a low occurrence rate and those on the low potential conseuence end have a higher occurrence rate. The examples selected by the applicant for these cases are shown in Table 7.1. These examples are reasonably homogeneous in terms of probability within each class.

Table 7.1. Classification of Postulated Accidents and Occurrences

| Class | NRC Description | Applicant's Examples |
|---|---|---|
| 1. | Trivial incidents | Included under routine releases |
| 2. | Small releases outside containment | Included under routine releases |
| 3. | Radioactive waste system failure | Off-gas charcoal bed rupture and liquid radwaste tank rupture |
| 4. | Fission products to primary system (BWR) | Fuel cladding defects and fuel failures induced by off-design transients |
| 5. | Fission products to primary and secondary systems (PWR) | Not applicable |
| 6. | Refueling accident | Fuel bundle drop and heavy object drop onto reactor core |
| 7. | Spent fuel handling accident | Fuel bundle drop into storage pool, heavy object drop onto fuel storage rack and spent fuel shipping cask drop |
| 8. | Accident initiation events considered in design-basis evaluation in the Safety Analysis Report | Loss of coolant accidents, steam line break accidents, rod drop accident, and instrument line break accident |
| 9. | Hypothetical sequence of failures more severe than Class 8 | Not considered |

Commission estimates of the dose which might be received by an assumed individual standing at the site boundary in the downwind direction, using the assumptions in the proposed Annex to Appendix D, are presented in Table 7.2. Estimates of the integrated exposure that might be delivered to the population within 50 miles of the site are also presented in Table 7.2. The man-rem estimate was based on the projected population within 50 miles of the site for the year 2020.

To rigorously establish a realistic annual risk, the calculated doses in Table 7.2 would have to be multiplied by estimated probabilities. The events in Classes 1 and 2 represent occurrences which are anticipated during plant operations, and their consequences, which are very small, are considered within the framework of routine effluents from the plant. Except for a limited amount of fuel failures, the events in Classes 3 through 5 a not anticipated during plant operation, but events of this type could occur sometime during the 40-year plant lifetime. Accidents in Classes 6 and 7 and small accidents in Class 8 are of similar or lower probability than accidents in Classes 3 through 5 but are still possible. The probability of large Class 8 accidents is very small. Therefore, when the consequences indicated in Table 7.2 are weighted by probabilities, the environmental risk is very low.

The postulated occurrences in Class 9 involve sequences of successive failures more severe than those required to be considered in the design bases of protection systems and engineered safety features. Their consequences could be severe. However, the probability of their occurrence is judged so small that their environmental risk is extremely low. Defense in depth (multiple physical barriers), quality assurance for design, manufacture and operation, continued surveillance and testing, and conservative design are all applied to provide and maintain a high degree of assurance that potential accidents in this class are, and will remain, sufficiently small in probability that the environmental risk is extremely low.

The NRC has performed a study to assess more quantitatively these risks. The initial results of these efforts were made available for comment in draft form on August 20, 1974[1] and released in final form on October 30, 1975.[2] This study, called the Reactor Safety Study, is an effort to develop realistic data on the probabilities and consequences of accidents in water-cooled power reactors, in order to improve the quantification of available knowledge related to nuclear reactor accident probabilities. The Commission organized a special group of about 50 specialists under the direction of Professor Norman Rasmussen of MIT to conduct the study. The scope of the study has been discussed with EPA and described in correspondence with EPA which has been placed in the NRC Public Document Room (letter, Doub to Dominick, dated June 5, 1973).

As with all new information developed which might have an effect on the health and safety of the public, the results of these studies will be assessed on a timely basis within the Regulatory process on generic or specific bases as may be warranted.

Table 7.2 indicates that the realistically estimated radiological consequences of the postulated accidents would result in exposures of an assumed individual at the site boundary which are less than those which would result from a year's exposure to the Maximum Permissible Concentrations (MPC) of 10 CFR Part 20. The table also shows the estimated integrated exposure of the population within 50 miles of the plant from each postulated accident. Any of these integrated exposures would be much smaller than that from naturally occurring radioactivity. When considered with the probability of occurrence, the annual potential radiation exposure of the population from all the postulated accidents is an even smaller fraction of the exposure from natural background radiation and, in fact, is well within naturally occurring variations in the natural background. It is concluded from the results of the realistic analysis that the environmental risks due to postulated radiological accidents are exceedingly small and need not be considered further.

## 7.2 TRANSPORTATION ACCIDENTS

The transportation of new fuel to the plant, of irradiated fuel from the reactor to a fuel reprocessing plant, and of solid radioactive waste from the reactor to burial grounds is within the scope of the AEC report entitled, *Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants*, dated December 1972. The environmental risks of accidents in transportation are summarized in Table 7.3.

Table 7.2. Summary of Radiological Consequences of Postulated Accidents[a]

| Class | Event | Estimated Fraction of 10 CFR Part 20 Limit at Site Boundary[b] | Estimated Dose to Population in 50-mile Radius, man-rem |
|---|---|---|---|
| 1.0 | Trivial incidents | c/ | c/ |
| 2.0 | Small releases outside containment | c/ | c/ |
| 3.0 | Radwaste system failures | | |
| 3.1 | Equipment leakage or malfunction | 0.07 | 6.1 |
| 3.2 | Release of waste gas storage tank contents | 0.28 | 24 |
| 3.3 | Release of liquid waste storage contents | < 0.001 | < 0.1 |
| 4.0 | Fission products to primary system (BWR) | | |
| 4.1 | Fuel cladding defects | c/ | c/ |
| 4.2 | Off-design transients that induce fuel failures above those expected | 0.003 | 0.6 |
| 5.0 | Fission products to primary and secondary systems (PWR) | N.A. | N.A. |
| 6.0 | Refueling accidents | | |
| 6.1 | Fuel bundle drop | 0.002 | 0.1 |
| 6.2 | Heavy object drop onto fuel in core | 0.012 | 1.1 |
| 7.0 | Spent fuel handling accident | | |
| 7.1 | Fuel assembly drop in fuel rack | 0.003 | 0.2 |
| 7.2 | Heavy object drop onto fuel rack | 0.005 | 0.4 |
| 7.3 | Fuel cask drop | 0.10 | 9.0 |
| 8.0 | Accident initiation events considered in design basis evaluation in the SAR | | |
| 8.1 | Loss-of-coolant accidents | | |
| | Small break | < 0.001 | < 0.1 |
| | Large break | 0.032 | 22 |
| 8.1(a) | Break in instrument line from primary system that penetrates the containment | < 0.001 | < 0.1 |
| 8.2(a) | Rod ejection accident (PWR) | N.A. | N.A. |
| 8.2(b) | Rod drop accident (BWR) | 0.004 | 0.9 |
| 8.3 (a) | Steam line breaks (PWR's outside containment) | N.A. | N.A. |
| 8.3(b) | Steam line break (BWR) | | |
| | Small break | 0.002 | 0.2 |
| | Large break | 0.013 | 1.1 |

[a]The doses calculated as consequences of the postulated accidents are based on airborne transport of radioactive materials resulting in both a direct and an inhalation dose. The staff's evaluation of the accident doses assumes that the applicant's environmental monitoring program and appropriate additional monitoring (which could be initiated subsequent to a liquid release incident detected by in-plant monitoring) would detect the presence of radioactivity in the environment in a timely manner such that remedial action could be taken if necessary to limit exposure from other potential pathways to man.

[b]Represents the calculated fraction of a whole body dose of 500 mrem, or the equivalent dose to an organ.

[c]These releases are expected to be in accord with Appendix I for routine effluents (i.e., 3 mrem per year per reactor to the whole body from liquid effluents and 5 mrem per year per reactor to the whole body from gaseous effluents). 322

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Table 7.3. Environmental Risks of Accidents in Transport of Fuel and Waste to and from a Typical Light-Water-Cooled Nuclear Power Reactor[a]

| | Environmental Risk |
|---|---|
| Radiological effects | Small[b] |
| Common (nonradiological) causes | 1 fatal injury in 100 reactor years; 1 nonfatal injury in 10 reactor years; $475 property damage per reactor year. |

[a]Data supporting this table are given in the Commission's "Environmental Survey of Transportation of Radioactive Materials to and from Nuclear Power Plants," WASH-1238, December 1972 and Supp. 1 (NUREG-75/038), April 1975.

[b]Although the environmental risk of radiological effects stemming from transportation accidents is currently incapable of being numerically quantified, the risk remains small regardless of whether it is being applied to a single reactor or a multireactor site.

## References


1. "Reactor Safety Study: An Assessment of Accident Risks in U. S. Commercial Nuclear Power Plants, Draft," WASH-1400, August 1974.
2. "Reactor Safety Study: An Assessment of Accident Risks in U. S. Commercial Nuclear Power Plants," WASH-1400 (NUREG 75/014), October 1975.

## 8. THE NEED FOR THE PLANT

### 8.1 DESCRIPTION OF THE POWER SYSTEM

In this section the need for the proposed generating capacity, 2300 MWe,* of the Black Fox Station, Units 1 and 2, is discussed. PSO has responsibility for 700 MWe (60.87%) of each unit, Associated Electric Cooperative, Inc. (Associated) has responsibility for 250 MWe (21.74%) and Western Farmers Electric Cooperative will own the remainder, 200 MWe (17.39%), of each unit. In the following discussion, the staff describes the service areas, forecasted market demands for electricity, and the forecasted reserve margins.

#### 8.1.1 Service Areas

Figure 8.1 shows PSO's service area. It embraces approximately 30,400 square miles, which is about 43% of the State of Oklahoma. Although the southwestern part of the state is warmer than the eastern part, even in Tulsa, where half of PSO's load is located, it is not unusual for the summer temperature to reach 100°F (38°C); a typical summer will have about 1900 cooling degree (°F) days.* Table 8.1 presents more information on heating and cooling degree days in the service area.

Table 8.1. Climate in PSO's Service Area

| Region of Service Area | Number of Customers in 1975 | Annual Heating Degree (°F) Days** Since 1966 | | | Annual Cooling Degree (°F) Days** Since 1966 | | |
|---|---|---|---|---|---|---|---|
| | | High | Median | Low | High | Median | Low |
| Northern | 37,402 | 4069 | 3900 | 3491 | 2147 | 1850 | 1610 |
| Central | 173,397 | 4077 | 3850 | 3443 | 2111 | 1900 | 1599 |
| Eastern | 56,388 | 3586 | 3418 | 2929 | 2111 | 1900 | 1740 |
| Western | 84,789 | 3424 | 3180 | 2766 | 2584 | 2190 | 1964 |

From ER, Supplement 1, Tables 1-8.6-12 and 1-8.6-13.

In 1974, PSO sold energy at retail to 307,353 residential customers who bought on behalf of a population that PSO estimates to be 921,000. This population is less than the number of people who live within the service area (approximately 1,200,000) because other utilities also sell there. Nonetheless, the population of 921,000 is about 34% of Oklahoma's total population (Oklahoma's estimated 1974 population of 2,709,000 is a projection based on the 1970 census population of 2,559,463). In addition, PSO is the sole source of electricity for eight municipal electric systems that serve an estimated population of 36,500 and is a partial source for three electric cooperatives that serve 65,100 people.

Western Farmers Electric Cooperative is a generation and transmission cooperative that serves Altus Air Force Base and 19 rural electric distribution co-ops, most of which are in western and southeastern Okalhoma (see Fig. 8.2). In 1974, the distribution co-ops served 128,227 residential customers who bought energy on behalf of a population that Western estimates to be 427,423. Western's ultimate consumers are in predominantly rural areas, while other utilities (e.g., PSO and OG&E) serve the cities and towns of its service area.

Associated Electric Cooperative Inc. makes capacity available for six Missouri generation and transmission cooperatives that in turn supply 40 distribution co-ops in Missouri and three in Iowa. These distribution co-ops supply ultimate consumers. Thus Associated's service area may be said to be all of non-urban Missouri and a small part of southern Iowa.

* Rated capacity is 2440 MWe; 140 MWe is on-site power requirement; 2300 MWe available for off-site consumption.

**Degree days are calculated with reference to 65°F. Thus, a day with an average temperature of 75°F contributes 10 cooling degree days to the annual total, and one within average temperature of 40°F contributes 25 heating degree days to the annual load.

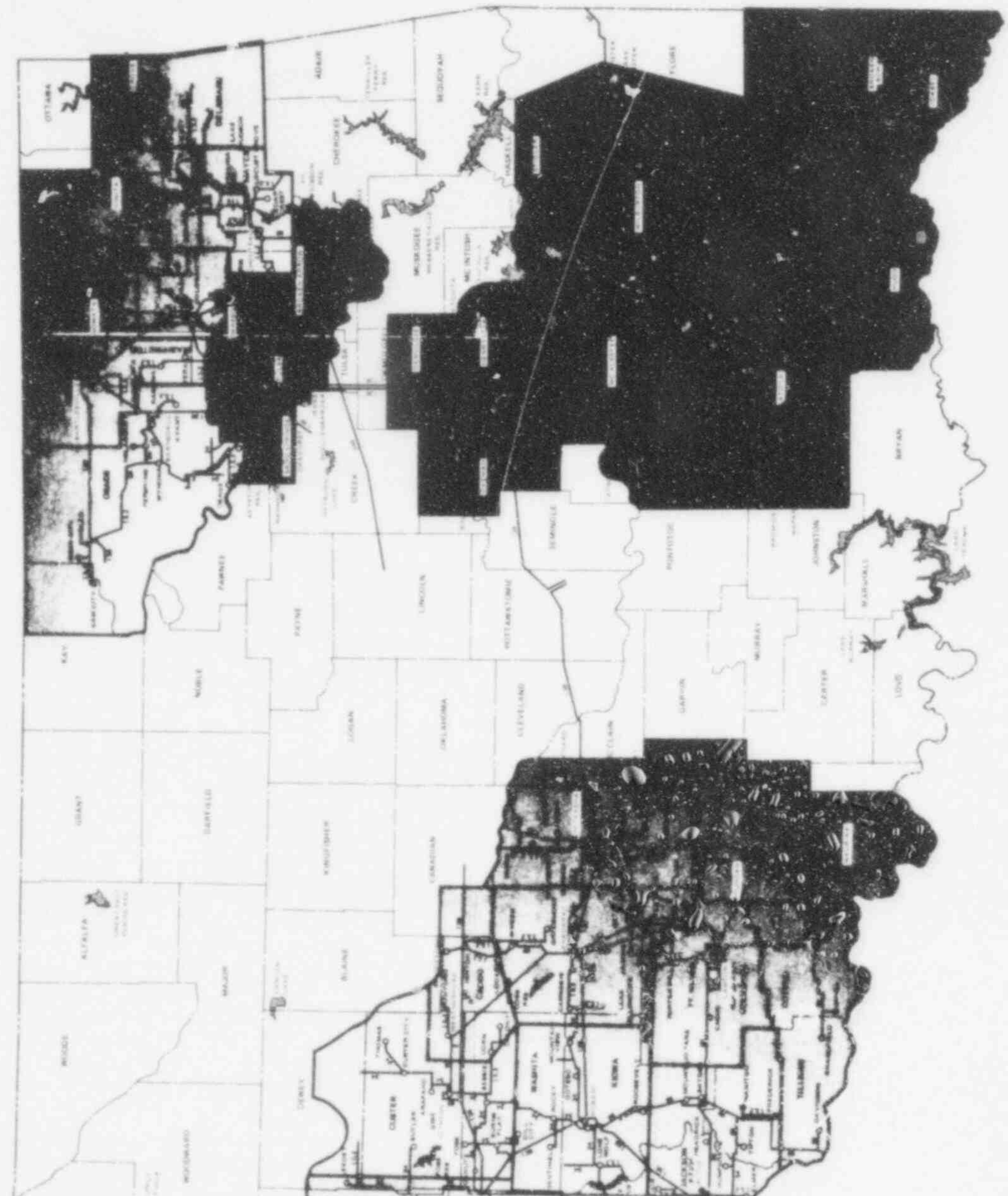

Fig. 8.1. PSO Electric System and District Boundaries.



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Fig. 8.2. Southwest Power Pool and Transmission Lines of Adjacent Systems. Modified from ER, Supp. 4, Fig. 1.1-1.

In 1974, Associated's distribution co-ops had 310,000 customers. This figure should be regarded with the rural population and the total population of Missouri in mind. In 1970, the rural population was 1,399,000 and the total population was 4,677,000.[1] A rough idea of the climate in Associated's service area is given by the city-population weighted state average values of heating and cooling degree days, which are 4900 and 823, respectively.[2]

By law, REA distribution co-ops cannot be formed to serve towns with a population of more than 1500; however, once a co-op is formed it may continue to serve a town whose population has grown to exceed this number or a town that has been annexed by another. [This principle has been explicitly affirmed by the Supreme Court of Missouri in the case of Missouri Public Service Co. vs. Platte-Clay Electric Cooperative (September 1966). This case was numbered 51,750.] For this reason, the staff believes that Associated will continue to serve areas with growing populations and in particular, former rural areas that are now suburban. The staff believes that Western is in a similar position with respect to the annexation of parts of its service area by large towns or cities.

### 8.1.2 Regional Relationships

PSO is a member of Group B of the Southwest Power Pool (SPP). SPP is one of the nine regional reliability councils that make annual reports to the Federal Power Commission (FPC) and that constitute the National Electric Reliability Council. SPP is principally concerned with planning for reliable transmission of power among its members. However, the SPP also requires that its members subscribe to certain minimum planning criteria for the maintenance of adequate reserve margins.

PSO interconnects and coordinates its power transactions with 11 other utilities.* It has a particularly intimate connection with the Grand River Dam Authority (GRDA), whose load PSO dispatches. For example, during 1974, PSO delivered 2,661,170 MW-hr (megawatt-hours) to, and received 1,512,167 MW-hr from, GRDA. Western is also a member of Group B of the SPP. This utility has interconnection agreements with four utilities and seven municipalities.**

PSO is also one of a group of 11 utilities, known as South Central Electric Companies, which on a seasonal basis exchanges up to 1500 MW of capacity with TVA. PSO interchanges 220 MW of that capacity.

Associated Electric Cooperatives, Inc. is a member of both SPP and Mid-America Inter-pool Network (MAIN), which is another regional reliability council. This utility is interconnected with 13 other utilities.† An agreement among PSO, Kansas Gas and Electric Co., Union Electric, and Associated provides for the maintenance of a 345-kV interconnection to allow coordinated interchanges of power and the transfer of emergency power. (This is the MO-KAN-OK 345 kV Agreement.)

Figure 8.2 shows the service areas of PSO, Western and Associated and the generating stations and main transmission lines of the SPP. Figure 8.3 shows Associated's present and planned interconnections and facilities.

## 8.2 POWER REQUIREMENTS

### 8.2.1 Past Energy Consumption and Power Levels

Table 8.2 indicates how energy generated by PSO was apportioned among its customers. In 1974, 58% of the energy was delivered to retail customers for consumption, while 35% was transferred to other utilities for resale.†† Table 8.3 shows that during the same year, nonfarm residential

*The utilities with which PSO interconnects are Oklahoma Gas and Electric Co., Western Farmers Electric Cooperative, Grand River Dam Authority, Southwestern Electric Power Co., West Texas Utilities, Kansas Gas and Electric Co., Southwestern Public Service, Associated Cooperative, Inc., The Empire District Electric Co., Union Electric Co., and Southwestern Power Administration.

**The utilities are PSO, Oklahoma Gas and Electric Co., Southwestern Power Administration and West Texas Utilities Co. The municipalities are Cherokee, Fairview, Laverne, Lindsay and Mangum, all in Oklahoma, and Electra and Vernon, both of which are in Texas.

†The utilities with which Associated interconnects are Arkansas-Missouri Power Co., City of Columbia, Missouri, The Empire District Electric Co., Grand River Dam Authority, Iowa Power and Light Co., Iowa Southern Utilities Co., Kansas City Power and Light Co., Kansas Gas and Electric Co., Missouri Public Service Co., Public Service Company of Oklahoma, St. Joseph Light and Power Co., Southwestern Power Administration, and Union Electric Co.

††Of the energy sold to other utilities for resale, 66% was delivered under contract and the remainder was sold during emergencies and as economy energy when such energy was available from PSO.

Fig. 8.3. Interconnected Missouri Cooperative Transmission Facilities. From ER, Supplement 1, Fig. 1-8.19-1.

Table 8.2. Disposition of Energy Generated by PSO

| Year | Net Generation, MW-hr | Delivery to Ultimate Consumers,[a] % | Net Transfers to Peers,[b] % | Net Transfers to Dependents,[c] % | Losses,[d] % |
|---|---|---|---|---|---|
| 1975 | | | | | |
| | 12,039,374 | 58 | 29 | 6 | 7 |
| | 9,905,614 | 68 | 17 | 7 | 8 |
| | 10,652,743 | 59 | 27 | 6 | 8 |
| | 9,969,682 | 55 | 31 | 6 | 8 |
| 1970 | 9,602,405 | 54 | 32 | 6 | 8 |
| | 7,355,899 | 65 | 20 | 7 | 8 |
| | 6,004,870 | 73 | 10 | 9 | 8 |
| | 5,293,878 | 74 | 8 | 9 | 9 |
| | 5,173,985 | 73 | 10 | 9 | 8 |
| 1965 | 4,583,820 | 74 | 8 | 9 | 9 |
| | 4,622,291 | 68 | 15 | 8 | 9 |
| | 4,430,789 | 67 | 17 | 8 | 9 |
| | 3,714,582 | 71 | 12 | 8 | 9 |
| | 3,144,692 | 76 | 6 | 8 | 0 |
| 1960 | 3,084,682 | 74 | 8 | 8 | 0 |

Source: FPC Form 12, Schedule 14

[a]These are retail customers.

[b]Peers are those utilities with retail sales plus losses exceeding 20,000 MW-hr. The FPC refers to them as Class I and II utilities.

[c]Dependents are those utlities with no capacity or sales plus losses less than 20,000 MW-hr. The FPC refers to them as Class III utilities.

[d]Losses include both transmission line losses and energy unaccounted for.

Table 8.3. Ultimate Consumption of PSO's Delivered Energy by Sector

| Year | Energy Delivered to Ultimate Consumers, MW-hr | Non-Farm Residential, % | Commercial, % | Industrial, % | Other, % |
|---|---|---|---|---|---|
| 1975 | | | | | |
| | 7,030,199 | 34 | 28 | 33 | 5 |
| | 6,704,312 | 34 | 28 | 33 | 5 |
| | 6,322,590 | 35 | 28 | 32 | 5 |
| | 5,478,475 | 35 | 29 | 31 | 5 |
| 1970 | 5,142,087 | 36 | 29 | 30 | 5 |
| | 4,815,978 | 34 | 29 | 33 | 4 |
| | 4,356,014 | 31 | 29 | 35 | 5 |
| | 3,913,868 | 29 | 28 | 38 | 5 |
| | 3,761,663 | 30 | 27 | 38 | 5 |
| 1965 | 3,414,499 | 30 | 27 | 38 | 5 |
| | 3,129,150 | 30 | 28 | 37 | 5 |
| | 2,947,936 | 31 | 28 | 38 | 3 |
| | 2,635,625 | 30 | 28 | 38 | 4 |
| | 2,383,751 | 28 | 27 | 41 | 4 |
| 1960 | 2,270,859 | 27 | 28 | 40 | 5 |

From: FPC Form 12, Schedule 10

customers purchased 34% of the energy sold at retail, while commercial and industrial customers accounted for 28% and 33%, respectively. The classification "other," which includes sales for street lighting, farming, and public authorities, accounted for the remaining 5% of the energy sold.

Table 8.4 gives the number of PSO's residential customers, their average annual energy consumption, and average annual bills for each year since 1960. Both the number of residential customers and the energy consumption per customer has risen every year since 1960. Because of the weather dependence of PSO's load, the percentage change in per-customer consumption between any year and its preceding one should not be taken as indicative of a trend. The column headed "Adjusted Revenue per Customer" gives a rough index of the bill, in 1974 dollars, that PSO's residential customers paid for the energy they purchased.* Note that consumption-per-customer increased by 18% between 1970 and 1974 while the adjusted revenue-per-customer actually declined. The ratio of "Adjusted Revenue per Customer" to "Energy per Customer" is an indication of the real price that PSO's residential customers paid for their electricity. It is no more than an indication because PSO has had a declining block rate structure.

Table 8.5 indicates how the energy distributed by Western's present members was apportioned among their customers. In 1974, 48% of the energy was sold to farm and rural residential customers, while 33% of the energy was sold to industrial and large commercial customers. Since 1968, an increasing percentage of sales has gone to residential customers who live in towns, but this percentage was still a modest 5.7% in 1974.

Table 8.6 gives the number of residential customers of the distribution co-ops that now constitute Western, their average annual energy consumption and average annual bills for each year since 1960. Both the number of residential customers and the energy consumption per customer has risen every year since 1965. Because of the weather dependence of Western's load, the percentage change of per-customer consumption between any year and its preceding one should not be taken as indicative of a trend. The column headed "Adjusted Revenue per Customer" gives a rough index of the bill, in 1974 dollars, that Western's residential customers paid for the energy they purchased.* Note that consumption-per-customer increased by 33% between 1970 and 1974 while the adjusted-revenue-per-customer rose only 4%. The ratio of "Adjusted Revenue per Customer" to "Energy per Customer" is an indication of the real price that Western's residential customers paid for their electricity. It is no more than an indication because Western has had a declining block rate strucutre.

Virtually all (99.9%) of PSO's domestic customers live in single-family dwellings, and 94% live in urban areas. On the other hand, most of Western's domestic customers live in rural areas. PSO believes that 9% of its customers use electric space heating, 16% use electric water heaters, and 50% use electric ranges. This utility also estimates that 45% of its residential customers have freezers and 75% have air conditioning. Western estimates that 18% of its customers have electric space heating, 28% have electric water heaters and 53% have electric freezers.

From 1966 to 1974, PSO's annual sales of electrical energy to industrial customers increased from 1400 MW-hr to 2200 MW-hr. A significant part of this increase can be traced to an increase in consumption of 233 MW-hr by the paper industry. Also, the steel and glass industries increased their annual consumption by 57 MW-hr and 58 MW-hr, respectively. The rest of the increase is the result of small increases by a variety of businesses. It is important to note that petroleum and natural gas extraction has not required an increased consumption of electrical energy. Extraction accounted for 205 MW-hr of PSO's sales in 1966, compared with 189 MW-hr in 1975. Petroleum refining and related activities accounted for 240 MW-hr in 1966 and 270 MW-hr in 1975.

According to Western, the petroleum industry accounts for a large part of its industrial load. Exploration, production, transportation, and refining facilities are all served from its lines.

PSO's retail sales are largest in the Tulsa area. During 1975, this utility sold 4,245,306 MW-hr in its Central Region, which coincides with Tulsa, while selling only 878,377 MW-hr in the Northern Region, 1,095,195 MW-hr in the Southern Region and 1,655,470 MW-hr in the Western Region. The distribution of summer peak loads is similar, as shown in Figure 8.4 for 1974.

Table 8.7 shows past and anticipated power levels and load factors. The meanings of these columns should be clearly understood. The maximum hourly load, or so-called "peak load," is the load imposed by PSO's retail customers plus the load imposed by "dependents" (those small utilities for which PSO is the principal source of electricity). Precisely the same customers are considered when the minimum hourly load is recorded and the average hourly load is calculated.** On the other hand, the average hourly generation is the total energy PSO generated divided by the number of hours in the year.

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*The "Adjusted Revenue per Customer" is the product of the "Revenue per Customer" and the Consumer Price Index.

**By FPC convention, the average hourly load also contains the losses.

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Table 8.4. PSO Residential Customers and Consumption

| Year | Number of Customers of the Year's End (Thousands) | Energy per Customer (kW-hr) | Percentage Increase of Energy per Customer over Previous Year | Revenue per Customer ($) | Adjusted Revenue per Customer ($)[a] |
|---|---|---|---|---|---|
| 1975 | 313.2 | 9389 | 11.55 | | |
| | 307.4 | 8417 | 1.76 | 206.68 | 206.68 |
| | 300.2 | 8271 | 1.43 | 197.02 | 218.52 |
| | 292.1 | 8154 | 12.73 | 193.88 | 228.48 |
| | 282.4 | 7233 | 1.47 | 173.22 | 210.52 |
| 1970 | 274.4 | 7128 | 10.46 | 170.42 | 216.17 |
| | 268.0 | 6453 | 15.98 | 157.71 | 211.91 |
| | 261.3 | 5564 | 15.65 | 140.71 | 199.24 |
| | 254.7 | 4811 | 0.75 | 125.55 | 185.18 |
| | 249.0 | 4775 | 7.62 | 125.64 | 190.68 |
| 1965 | 243.8 | 4437 | 6.42 | 119.90 | 187.10 |
| | 238.3 | 4169 | 6.43 | 116.18 | 184.38 |
| | 232.2 | 3917 | 13.18 | 113.79 | 183.10 |
| | 227.9 | 3461 | 15.10 | 105.88 | 172.41 |
| | 224.5 | 3007 | 1.35 | 94.61 | 155.73 |
| 1960 | 221.2 | 2967 | | 94.30 | 156.74 |

From PSO's annual reports to its stockholders.

[a]The adjusted revenue per customer represents the revenue per customer in 1974 dollars as determined by the Consumer Price Index.



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Table 8.5. Total Annual Energy Sales by Western's Members by Consumer Classification

| Year | Farm and Rural Residential, % | Town Residential, % | Irrigation Consumers, % | Small Commercial, % | Large Commercial and Industrial, % | All Others, % | Total-MWH |
|---|---|---|---|---|---|---|---|
| 1964 | 41.7 | 2.2 | 2.6 | 19.0 | 32.2 | 2.2 | 681,941 |
| 1965 | 41.3 | 2.1 | 2.1 | 17.7 | 34.4 | 2.3 | 788,862 |
| 1966 | 40.6 | 2.1 | 1.8 | 16.0 | 37.3 | 2.2 | 901,412 |
| 1967 | 35.9 | 2.0 | 2.0 | 22.9 | 35.6 | 1.6 | 1,106,028 |
| 1968 | 41.0 | 2.9 | 1.4 | 15.5 | 37.6 | 1.6 | 1,094,920 |
| 1969 | 43.9 | 3.3 | 1.4 | 13.9 | 35.6 | 1.9 | 1,213,866 |
| 1970 | 45.1 | 3.6 | 2.0 | 13.6 | 33.9 | 1.7 | 1,360,783 |
| 1971 | 44.7 | 3.8 | 2.2 | 13.1 | 34.7 | 1.6 | 1,513,458 |
| 1972 | 46.5 | 4.3 | 1.7 | 12.3 | 33.5 | 1.6 | 1,728,551 |
| 1973 | 47.0 | 5.6 | 0.9 | 11.7 | 33.7 | 1.1 | 1,858,600 |
| 1974 | 47.5 | 5.7 | 1.5 | 11.0 | 33.1 | 1.2 | 2,066,748 |
| 1975 | Data Not Available | | | | | | |

Source: Western Farmers Electric Co-op (Docket STN 50-557)



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Table 8.6. Western Residential Customers and Consumption

| Year | Number of Customers, thousands | Energy per Customer, kWh | Percentage Increase of Energy per Customer over Previous Year | Revenue per Customer, $ | Adjusted Revenue per Customer, $[a] |
|---|---|---|---|---|---|
| 1965 | 90 | 3801 | | 117.37 | 183.15 |
| | 92 | 4187 | 10.0 | 122.22 | 185.50 |
| | 94 | 4458 | 6.5 | 125.97 | 185.80 |
| | 96 | 5008 | 12.3 | 133.56 | 189.12 |
| | 99 | 5784 | 15.5 | 144.40 | 194.03 |
| 1970 | 103 | 6442 | 11.4 | 153.53 | 194.74 |
| | 109 | 6734 | 4.5 | 157.32 | 191.20 |
| | 117 | 7512 | 11.6 | 169.18 | 199.37 |
| | 123 | 7945 | 5.8 | 187.09 | 207.51 |
| | 128 | 8580 | 8.0 | 202.94 | 202.94 |
| 1975 | Data Not Available | | | | |

From information (Docket No. STN 50-577) supplied by Western.

[a]The adjusted revenue per customer represents the revenue per customer in 1974 dollars as determined by the Consumer Price Index.

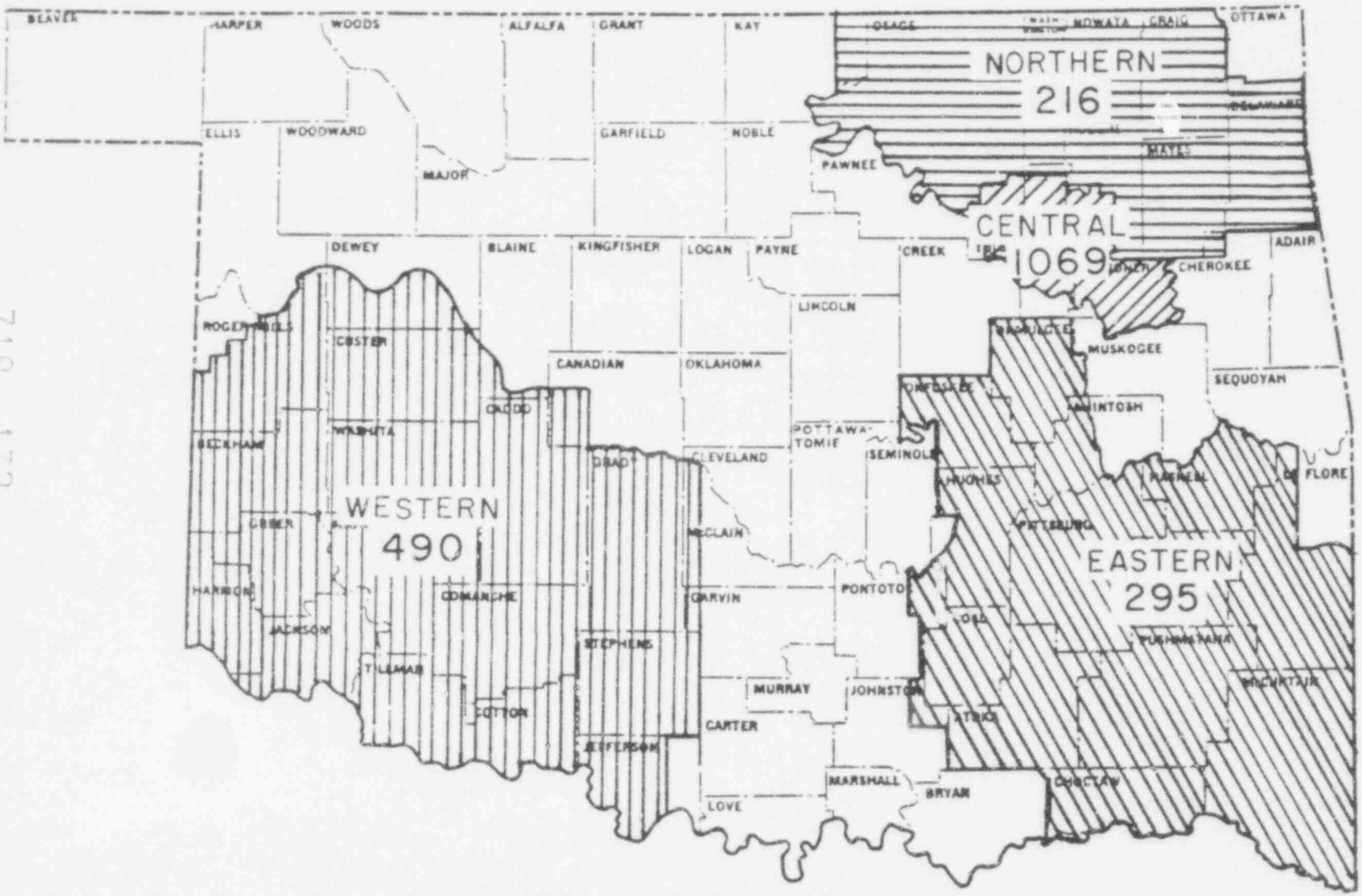


Fig. 8.4. PSO's 1974 Summer Peak Load (in megawatts). From ER, Supplement 1, Fig. 1-8.28-1.

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Table 8.7. PSO Power Levels and Load Factor

| Year | Maximum Hourly Load,[a,b] MW: PSO Forecast | Staff's Upper Forecast | Staff's Lower Forecast | Percentage Increase over Previous Year: PSO Forecast | Staff's Upper Forecast | Staff's Lower Forecast | Minimum Hourly Load,[b] MW | Percentage Increase over Previous Year | Average Hourly Load,[c] MWh/h: PSO Forecast | Staff's Upper Forecast | Staff's Lower Forecast | Percentage Increase over Previous Year: PSO Forecast | Staff's Lower Forecast | Staff's Upper Forecast | Load Factor,[d] %: PSO Forecast | Staff's Forecast |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1987 | 5248 | 4254 | 3677 | 7.5 | 6.4 | 4.9 | | | 2362 | 2204 | 1859 | 7.5 | 6.4 | 4.9 | 45.0 | 50.6 |
| | 4882 | 4092 | 3505 | 7.3 | 6.4 | 4.9 | | | 2197 | 2071 | 1772 | 7.2 | 6.4 | 4.9 | 45.0 | 50.6 |
| 1985 | 4550 | 3846 | 3341 | 7.4 | 6.4 | 4.9 | | | 2050 | 1947 | 1689 | 7.3 | 6.4 | 4.9 | 45.1 | 50.6 |
| | 4237 | 3615 | 3185 | 7.5 | 6.4 | 4.9 | | | 1911 | 1830 | 1610 | 6.2 | 6.4 | 4.9 | 45.1 | 50.6 |
| | 3940 | 3397 | 3037 | 7.6 | 6.4 | 4.9 | | | 1800 | 1720 | 1535 | 6.8 | 6.4 | 4.9 | 45.7 | 50.6 |
| | 3661 | 3193 | 2895 | 7.6 | 6.4 | 4.9 | | | 1686 | 1616 | 1463 | 5.6 | 6.4 | 4.9 | 46.1 | 50.6 |
| | 3401 | 3001 | 2759 | 7.1 | 6.4 | 4.9 | | | 1596 | 1519 | 1395 | 5.9 | 6.4 | 4.9 | 46.9 | 50.6 |
| 1980 | 3158 | 2824 | 2631 | 7.7 | 6.4 | 4.9 | | | 1507 | 1427 | 1330 | 6.7 | 6.4 | 4.9 | 47.7 | 50.6 |
| | 2931 | 2654 | 2508 | 7.8 | 6.4 | 4.9 | | | 1413 | 1342 | 1268 | 6.6 | 6.4 | 4.9 | 48.2 | 50.6 |
| | 2719 | 2495 | 2391 | 7.9 | 6.4 | 4.9 | | | 1325 | 1261 | 1208 | 4.9 | 6.4 | 4.9 | 48.7 | 50.6 |
| | 2521 | 2345 | 2279 | 5.6 | 6.4 | 4.9 | | | 1263 | 1185 | 1152 | 5.4 | 6.4 | 4.9 | 50.1 | 50.6 |
| | 2390 | 2204 | 2172 | 15.4 | 6.4 | 4.9 | | | 1198 | 1114 | 1098 | 14.4 | 6.4 | 4.9 | 50.1 | 50.6 |
| 1975[e] | 2071 | | | 0.0 | | | 540 | 9.6 | 1047 | | | 6.1 | | | 50.6 | |
| | 2070 | | | 12.3 | | | 500 | -4.4 | 987 | | | 5.5 | | | 47.7 | |
| | 1843 | | | 0.8 | | | 523 | 15.7 | 936 | | | 5.1 | | | 50.8 | |
| | 1826 | | | 12.5 | | | 452 | 7.4 | 891 | | | 13.8 | | | 48.6 | |
| | 1610 | | | 3.9 | | | 421 | 8.8 | 783 | | | 5.9 | | | 48.5 | |
| 1970 | 1550 | | | 6.7 | | | 387 | 9.0 | 739 | | | 9.3 | | | 47.7 | |
| | 1452 | | | 12.7 | | | 355 | 6.6 | 677 | | | 11.2 | | | 46.6 | |
| | 1289 | | | 10.5 | | | 333 | 11.0 | 608 | | | 10.1 | | | 47.2 | |
| | 1166 | | | 2.5 | | | 300 | 6.4 | 557 | | | 4.7 | | | 47.4 | |
| | 1138 | | | 13.6 | | | 282 | 9.7 | 526 | | | 9.0 | | | 46.4 | |
| 1965 | 1000 | | | 4.2 | | | 257 | 10.8 | 484 | | | 4.5 | | | 48.4 | |
| | 960 | | | 11.4 | | | 232 | 11.0 | 442 | | | 5.5 | | | 45.9 | |
| | 862 | | | 11.9 | | | 209 | 6.6 | 419 | | | 12.0 | | | 48.6 | |
| | 770 | | | 12.4 | | | 196 | 9.5 | 374 | | | 10.7 | | | 48.6 | |
| | 605 | | | 4.6 | | | 179 | 9.8 | 338 | | | 4.8 | | | 49.4 | |
| 1960 | 635 | | | - | | | 162 | - | 323 | | | - | | | 49.2 | |

[a] The maximum hourly load is also called the peak load.

[b] The maximum and minimum hourly loads are composed of the demands made by PSO's retail customers plus the demands made by dependent utilities.

[c] The average hourly load is calculated by dividing the sum of three terms by the number of hours in the year. The three terms are the energy delivered to ultimate consumers, the energy transferred to dependents, and the energy that was lost.

[d] The load factor is the ratio of the average hourly load to the maximum hourly load.

[e] Values for 1975 and before are actual.

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In the past, PSO has usually imported energy at the time of its system's peak and exported energy at other times during the year. This practice makes PSO's ownership of rarely used (peaking) capacity unnecessary and allows this utility to earn money with capacity that would otherwise be idle. The minimum hourly load is an indication of the capacity a utility must always have available (so-called "baseload" capacity) to serve its retail customers and dependents. Of course, almost all of the time, a utility needs more capacity than that necessary to meet its minimum load. The average hourly load roughly indicates the average capacity needed. The minimum hourly load and the average hourly load have more than doubled since 1965. On the average, each has grown at a little more than 7% per year.

Information on the energy sold, peak load, and load factor for Associated is presented in Table 8.8. Associated's primary customers are six G & T co-ops that in turn sell to 40 distribution co-ops. These distribution co-ops sell to ultimate consumers. The staff believes that these consumers are predominantly nonfarm residential customers. These customers are more likely than their urban counterparts to own electric freezers and to heat their homes with liquid petroleum gas (LPG). Since 1971, Associated has also sold a significant amount of energy to an aluminum plant.

### 8.2.2 Applicant's Forecast of Power Requirements

PSO believes that new capacity will be required to furnish energy to new industries and expanded commerce. Table 8.7 shows a PSO forecast for all years through 1987. Associated expects increased residential demand from growing suburbs and their ultimate consumers' conversion from the use of LPG to electricity for space heating. Associated's forecast is shown in Table 8.8. Western expects growth in its residential load because of increased use of electric space heating and growth in its large commercial loads because of increased use of electric pumps to extract petroleum and natural gas from the ground. Western's forecast is shown in Table 8.9. A description of forecasting methodology for each of these utilities is given in Section 1.1.1.2 of the ER. In addition, Western has submitted a separate volume entitled "Power Requirements Study" (Docket STN 50-557).

### 8.2.3 Staff's Forecast of Power Requirements

#### 8.2.3.1 Overview of the Staff's Forecast

During preparation of its forecast of the need for the capacity of the BFS, the staff considered both national and regional projections of future economic growth and the market demand for electricity. The staff began with the assumption that the regional growth in demand will be the same as that projected for the nation as a whole. The staff expects a difference between these rates of growth only when fundamental regional demographic or economic variables are projected to be different from their national counterparts. Considerable weight has been given to the forecast of national demand for electrical capacity prepared by the U. S. Federal Energy Administration (FEA) and the forecasts of regional growth in population and economic activity prepared by the U. S. Department of Commerce and the U. S. Department of Agriculture (OBERS). The staff has also considered the work of the Center for Economic and Management Research of the University of Oklahoma and that of the Oklahoma Energy Advisory Council.

The FEA's forecast appears in the publication "1976, National Energy Outlook," which is the latest result of the most comprehensive energy analysis this nation has undertaken.[3] This report considers the future demand for electricity within seven different scenarios. The greatest rate of growth, 6.4%, in the consumption of electrical energy is projected to occur if the nation implements a vigorous program to increase the end use of electricity in place of oil and gas. The least rate of growth, 4.9%, is projected to occur if the nation adopts a full set of conservation policies. If the U. S. energy policy continues as in the recent past and if the price of imported oil remains at $13 per barrel, then the "business-as-usual," or "reference," scenario projects a growth rate of 5.4% in the consumption of electrical energy. This is nearly the same as the average of eight other projected national growth rates, 5.6%, that have been suggested by various groups since mid-1973 (see p. 239 of Ref. 3).

The 1972 OBERS Projections, Series E, provide forecasts of both regional and national long-run economic growth.[4] These are the most widely used projections in regional economic planning. However, the OBERS Projections do not incorporate the effects of the rise in price of OPEC oil and so must be tempered by the staff's judgment of these effects.

#### 8.2.3.2 Staff's Forecast

Table 8.10 displays the OBERS forecast for the percentage growth of population, personal income and the earnings of those who work in mining, manufacturing and commerce for the United States, Oklahoma and the metropolitan areas of Tulsa and Lawton. OBERS forecasts that the population of

Table 8.8. Associated's Load and Energy

| Year | Cooperative Demand, MWe | Aluminum Load, MWe | Total Demand, MWe | % Increase over Previous Year | Cooperative Energy, MW-h | Aluminum Load, MW-h | Total Energy, MW-h | % Increase over Previous Year | Load Factor, % |
|---|---|---|---|---|---|---|---|---|---|
| Historical | | | | | | | | | |
| 1965 | 352 | 0 | 352 | | 1,860,818 | 0 | 1,860,818 | | 60 |
| | 427 | 0 | 427 | 21 | 2,060,033 | 0 | 2,060,033 | 10.7 | 55 |
| | 473 | 0 | 473 | 10.7 | 2,256,949 | 0 | 2,256,949 | 9.6 | 54 |
| | 520 | 0 | 520 | 9.9 | 2,617,993 | 0 | 2,617,993 | 16.0 | 57 |
| | 585 | 0 | 585 | 12.5 | 2,928,110 | 0 | 2,928,110 | 11.8 | 57 |
| 1970 | 650 | 0 | 650 | 11.1 | 3,272,486 | 0 | 3,272,486 | 11.7 | 57 |
| | 700 | 124 | 824 | 26.8 | 3,627,670 | 620,460 | 4,248,130 | 29.8 | 59 |
| | 848 | 124 | 972 | 18.0 | 4,201,762 | 1,092,445 | 5,294,207 | 24.6 | 62 |
| | 910 | 125 | 1035 | 6.5 | 4,517,997 | 1,094,547 | 5,612,544 | 6.0 | 62 |
| | 1038 | 125 | 1163 | 12.4 | 4,806,449 | 1,090,239 | 5,896,688 | 5.1 | 58 |
| Projected by Associated | | | | | | | | | |
| 1975 | 1159 | 125 | 1284 | 10.4 | 5,502,000 | 1,095,000 | 6,597,000 | 11.9 | 59 |
| | 1281 | 250 | 1531 | 19.2 | 6,097,000 | 1,642,500[a] | 8,287,000 | 25.6 | 62 |
| | 1411 | 250 | 1661 | 8.5 | 6,771,000 | 2,190,000 | 8,961,000 | 8.1 | 62 |
| | 1577 | 250 | 1827 | 10.0 | 7,536,000 | 2,190,000 | 9,726,000 | 8.5 | 61 |
| | 1764 | 250 | 2014 | 10.2 | 8,388,000 | 2,190,000 | 10,578,000 | 8.8 | 60 |
| 1980 | 1972 | 250 | 2222 | 10.3 | 9,336,000 | 2,190,000 | 11,526,000 | 9.0 | 60 |
| | 2205 | 250 | 2455 | 10.5 | 10,391,000 | 2,190,000 | 12,581,000 | 9.2 | 59 |
| | 2462 | 250 | 2712 | 10.5 | 11,596,000 | 2,190,000 | 13,786,000 | 6.6 | 58 |
| | 2762 | 250 | 3012 | 11.1 | 12,964,000 | 2,190,000 | 15,514,000 | 9.9 | 57 |
| | 3099 | 250 | 3349 | 11.2 | 14,494,000 | 2,190,000 | 16,684,000 | 10.1 | 57 |
| 1985 | 3477 | 250 | 3727 | 11.3 | 16,204,000 | 2,190,000 | 18,394,000 | 10.2 | 56 |
| | 3901 | 250 | 4151 | 11.4 | 18,116,000 | 2,190,000 | 20,306,000 | 10.4 | 56 |
| | 4369 | 250 | 4619 | 11.3 | 20,247,000 | 2,190,000 | 22,437,000 | 10.5 | 55 |
| | 4902 | 250 | 5152 | 11.5 | 22,636,000 | 2,190,000 | 24,826,000 | 10.6 | 55 |
| | 5500 | 250 | 5750 | 11.7 | 25,307,000 | 2,190,000 | 27,497,000 | 10.8 | 55 |
| | 6171 | 250 | 6421 | 11.7 | 28,293,000 | 2,190,000 | 30,483,000 | 10.9 | 54 |

[a]Assumes second pot line is on equivalent of six months in 1976.

Modified from ER, Table 1.1-1b.

Table 8.9. Historical and Projected Western Net System, Peak Load Demands and Energy Requirements

| Year | MWe | MWh |
|---|---|---|
| Historical | | |
| 1965 | 125 | 620,675 |
| | 140 | 709,287 |
| | 150 | 789,137 |
| | 165 | 860,204 |
| | 196 | 955,507 |
| 1970 | 209 | 1,054,027 |
| | 237 | 1,162,482 |
| | 255 | 1,331,914 |
| | 286 | 1,431,717 |
| 1974 | 488 | 2,308,820 |
| Projected | | |
| 1975 | 511 | 2,476,765 |
| | 605 | 2,877,000 |
| | 706 | 3,224,000 |
| | 781 | 3,605,000 |
| | 824 | 4,009,000 |
| 1980 | 950 | 4,395,000 |
| | 1042 | 4,817,000 |
| | 1148 | 5,281,000 |
| | 1262 | 5,790,000 |
| | 1391 | 6,352,000 |
| 1985 | 1531 | 6,968,000 |
| | 1683 | 7,644,000 |
| | 1853 | 8,386,000 |
| | 2040 | 9,203,000 |
| | 2246 | 10,123,000 |
| 1990 | 2470 | 11,136,000 |

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719 136

Table 8.10. The OBERS Forecast of Percentage Growth in Population and Selected Economic Variables

| | 1970-1980 | | | | | 1980-1990 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | USA | Oklahoma | Tulsa BEA[a] | Tulsa SMSA[b] | Lawton SMSA[c] | USA | Oklahoma | Tulsa BEA[a] | Tulsa SMSA[b] | Lawton SMSA[c] |
| Population | 0.93 | 0.72 | 0.82 | 1.13 | 1.00 | 0.96 | 0.81 | 0.66 | 0.89 | 0.56 |
| Personal income | 4.2 | 4.0 | 4.1 | 4.2 | 1.8 | 3.6 | 3.6 | 3.4 | 3.5 | 3.2 |
| Earnings: | | | | | | | | | | |
| Mining | 1.4 | 0.0 | -0.5 | 0.1 | (e)[d] | 1.2 | 0.1 | -0.2 | 0.1 | (s)[e] |
| Manufacturing | 3.5 | 4.4 | 3.7 | 3.6 | 3.8 | 2.9 | 3.8 | 3.5 | 3.5 | 2.8 |
| Wholesale and retail trade | 3.7 | 3.7 | 3.7 | 3.8 | 2.5 | 3.0 | 3.0 | 2.8 | 2.8 | 2.9 |

[a]The counties that constitute the Tulsa BEA and are also within PSO's service area are Delaware, Mayes, Nowata, Osage, Rogers, Tulsa, Wagoner and Washington. The counties that are in the Tulsa BEA but are not in the PSO service are are Adair, Cherokee, Kay, McIntosh, Muskogee, and Okmulgee in Oklahoma, and Benton, Madison, and Washington in Arkansas.

[b]The counties that constitute the Tulsa SMSA are Creek, Osage, and Tulsa. Creek County is not in PSO's service area.

[c]Commanche County, which is within PSO's service area, is the Lawton SMSA.

[d](e) Represents zero to 19.9% of the true value.

[e](s) = to small to forecast.

Oklahoma will grow more slowly than that of the nation as a whole but that the growth in personal income in Oklahoma will be similar to the nationwide growth. An indirect indication of a change of business activity is a change in the wages and salaries of those who work in the activity. With the exception of the Lawton area, the total earnings of those who work in wholesale and retail trades are expected to grow at the same rate as those similarly employed throughout the nation. It is forecasted that during the 1980s, Oklahoma and the Tulsa area will experience a faster growth in the earnings of those engaged in manufacturing than the nation as a whole. On the other hand, a long-term growth in Oklahoma's petroleum and natural gas extraction is not expected. This accounts for the negligible growth or decline in the total earnings of Oklahomans engaged in mining.

As has been noted, OBERS forecasts were made without trying to anticipate the effects of the high price of imported oil. The staff believes that one such effect deserves mention. The interstate price of natural gas will rise more quickly than it otherwise would have. Since Oklahoma exports natural gas, the price rise will result in a short-term increase in personal income relative to the rest of the nation. The long-term effect is uncertain because it depends upon how long Oklahoma continues to export, the price of gas within Oklahoma, and the price of imported animal feed and organic chemicals, which in part depends on the price of natural gas.

Bearing in mind the uncertainties which attend such statements, the staff believes that economic growth in PSO's service area and in Oklahoma will be similar to that experienced by the nation as a whole, and that therefore the long-term growth in demand for electrical energy will be between 4.9% and 6.4%. Both PSO's and the staff's forecasts for the average hourly load are shown in Figure 8.5. The staff also believes that the long-term growth in the maximum hourly load will be less than it was during the last decade because 75% of PSO's customers already own air conditioners. Since load factors have remained fairly stable in the past despite varying economic conditions, the staff believes they will remain so in the future. Thus, the staff forecasts that peak load will grow at roughly the same rate as average hourly load. Figure 8.6 shows past and projected maximum hourly load growth.

The staff believes that the principal source of Western's growth will come from new customers with all-electric homes. This utility estimates that 85% of its new connections served customers with electric space heating, water heating and freezers. In order to assess the plausibility of Western's forecast of its growth in energy sales, the staff has supposed that the number of Western's residential customers will grow at the same rate as that projected for Oklahoma as a whole and that each new customer would consume 30,000 kW-hr per year. OBERS projects (see Table 8.10) a population growth rate of 0.72% per year from 1970 to 1980 and an 0.81% per year rate in the following decade. The Oklahoma Employment Security Division projects 1.5% per year for the next ten years.[5] The lowest population growth rate, 0.72% per year, results in a rate of growth of consumption due to new customers of 2.3% per year between 1974 and 1985, while the 1.5% per year growth rate leads to a 4.5% per year growth rate in consumption. On the other hand, if Western's residential customer growth rate continues to be 4.0% per year as it was last year and overall in the nine-year period from 1965 to 1974, then the overall growth rate will be approximately 11% per year. The staff believes that Western's long-term growth forecast may be somewhat high but that in view of the uncertainty in its customer growth (similar to that found below for Associated) Western's projection is reasonable.

Associated has grown at a rapid rate since 1965. It further expects to increase its aluminum load from its present value of 125 MW to 250 MW in 1976. Beyond that time it is difficult to forecast Associated's growth for two reasons. First, the OBERS projections do not distinguish Associated's service area from the cities and towns it surrounds. Second, the future price and availability of LPG is uncertain. The first reason is important because the most important part of the increase in the number of Associated's ultimate customers is not due to a general growth in Missouri nor any broadly defined part of it, but rather to a willingness of Missourians to live in new suburban areas that were formerly rural. The second reason is important because many of Associated's ultimate customers use LPG for space heating. The staff believes that a significant number of these poeple would convert to electrical space heating if they believed LPG supplies were uncertain or too highly priced.

The staff believes that Associated has projected an implausibly high long-term growth rate (~ 10%) for itself (see Table 8.8) and that a long-term growth rate of 6.5% is more likely. Nonetheless, the uncertainties which attend a forecast for Associated's load cannot be smaller than the uncertainty which attends a forecast of the number of Associated's customers, and this uncertainty is large.

### 8.2.4 The Impact of Energy Conservation and Substitution on Need for Power

Recent energy shortages have focused the nation's attention on the importance of energy conservation as well as on measures by which to increase the domestic supply of alternative energy sources. The need to conserve energy and to promote substitution of other energy sources for oil and gas have been recommended by the "Report to the President on the Nation's Energy Future"

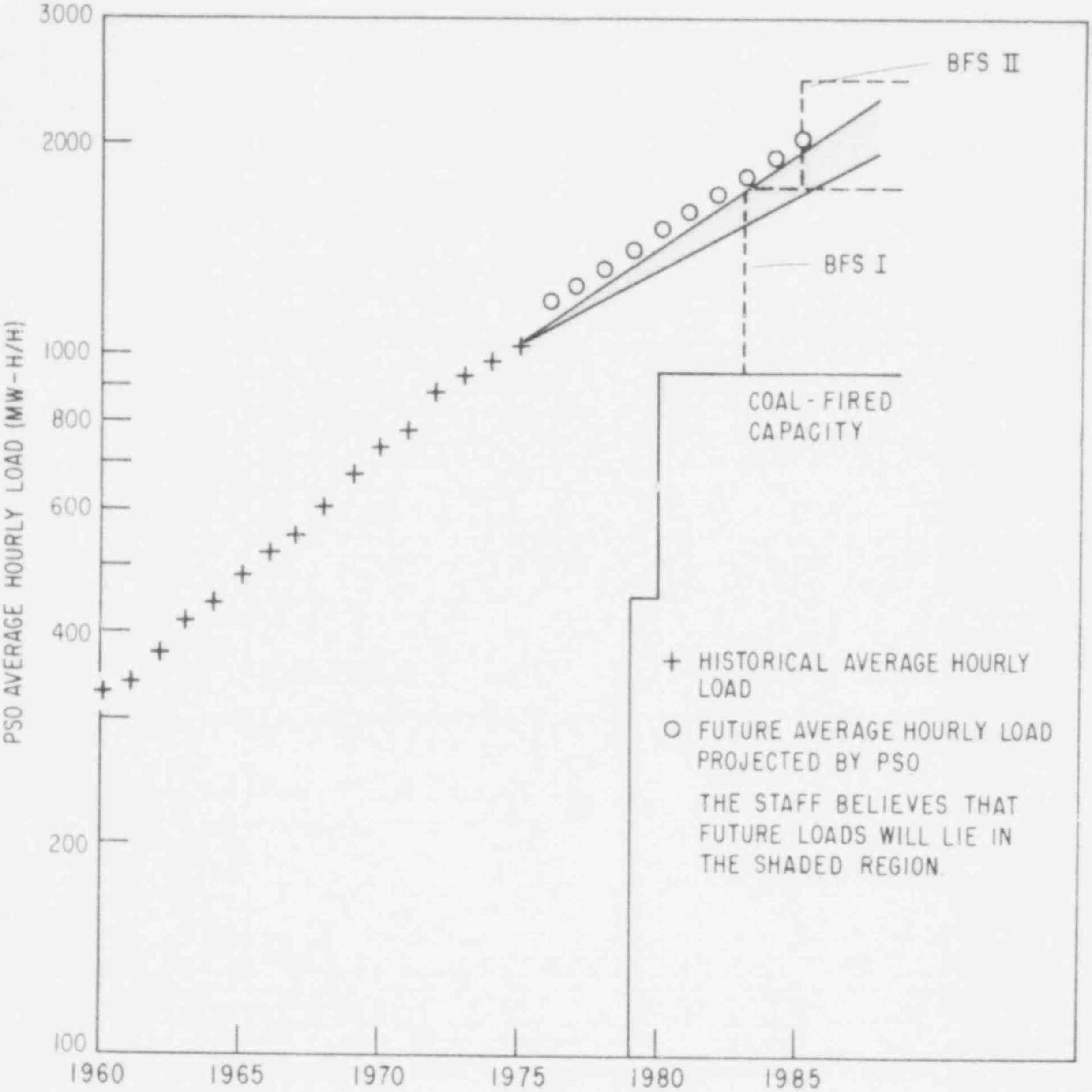


Fig. 8.5. PSO Average Hourly Load.

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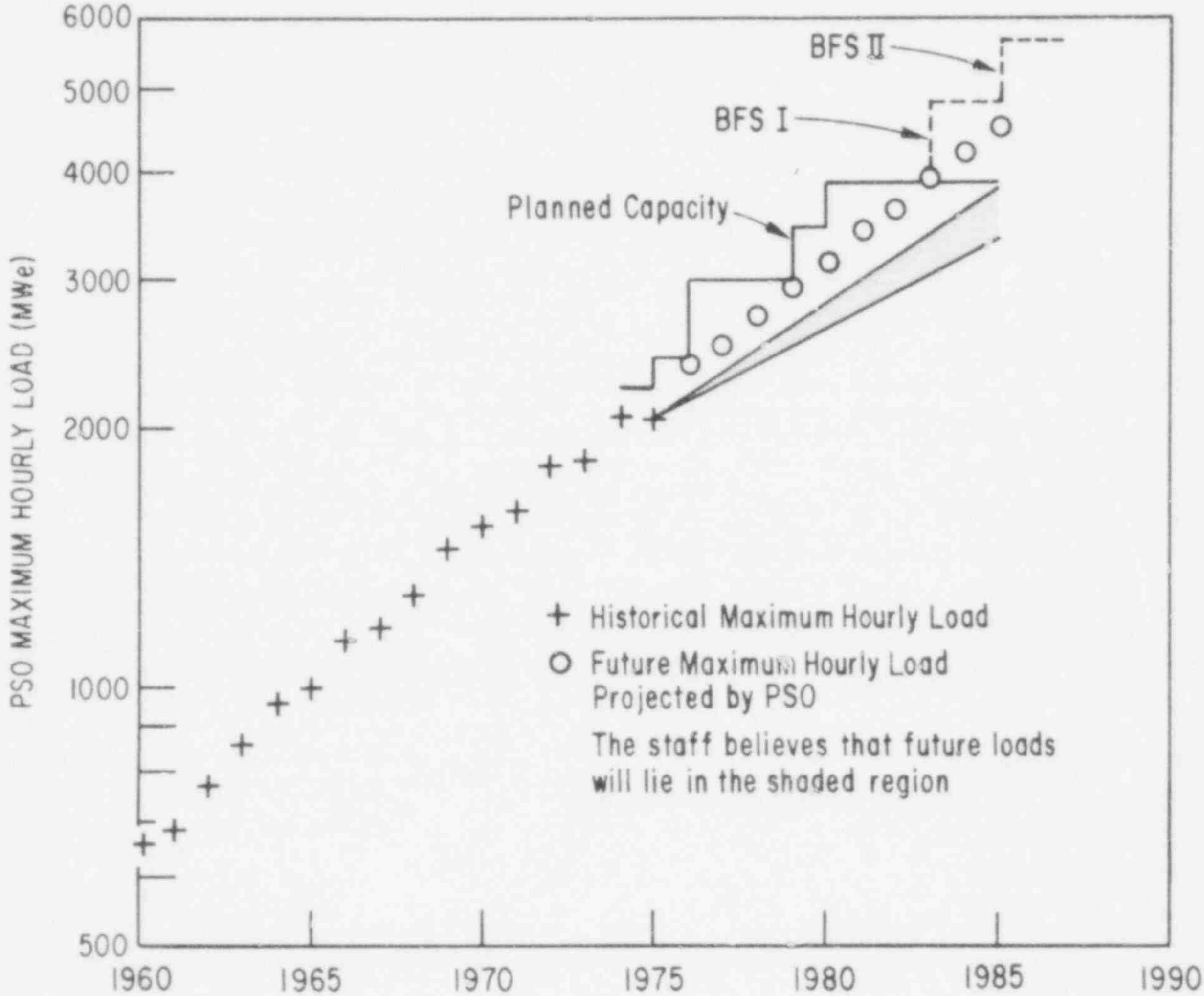


Fig. 8.6. PSO Maximum Hourly Load.

as major efforts in regaining national energy self-sufficiency by 1980.[6] In the following sections, the staff considers conservation of energy as related to the need for the electricity to be produced by the Black Fox Station.

8.2.4.1 Recent Experience

Implementation of energy conservation measures by households, business, and government has already contributed to a substantial reduction of growth in the consumption of electricity nationally since the third quarter of 1973. In the 30 months between October 1972 and March 1975, PSO's monthly total energy sales were below PSO's forecast 24 times and above forecast six times (ER, p. 1.1-31). Similarly, Western's sales were below forecast 20 times and above forecast ten times. Associated's sales were above forecast 18 times and below 12 times. Group B of the Southwest Power Pool showed sales that were below forecast 19 times and were above 11 times for the same period. Energy conservation and the general economic climate probably both contributed to the reduction in growth of energy sales, but the magnitude of each factor is unknown. Because of limited trend data and other data deficiencies, the interpretation of the significance of energy conservation impacts on the forecasted need for power in the general service areas over the next six to ten years is highly uncertain.

Much will depend, of course, on the future decisions of consumers and governmental agencies in responding to the energy crisis and on potential developments in energy supply and demand factors that might ease the energy crisis or cause it to worsen. However, as time progresses, historical information of these kinds and the actual data on power demand impacts in the general service areas will provide a more significant basis for demand projections.

8.2.4.2 Promotional Advertisement and Conservation Information Services

In the past, the applicants have attempted, through advertising, to accelerate the demand for electricity in their service areas. Generally, the major thrust of advertising was to promote demand during off-peak periods, thereby replacing expensive peaking capacity with expanded, lower cost, baseload capacity. Notably, electric space heating (for summer peaking systems), lighting, and water heating have been promoted to offset the higher seasonal peaking demands and thus to level loads.

PSO has terminated promotional advertising to ultimate consumers and now has a program which, by direct mail and mass media advertising, disseminates information designed to promote efficient residential usage of electricity (see below). Accordingly, elimination of promotional advertising is no longer an available measure with which the participants can dampen demand. On the other hand, promotional advertising by purveyors of electrical appliances and equipment has not been eliminated. For example, throughout the U. S. $4,073,000 was spent on newspaper advertisements of air conditioners in 1974.[7]

According to the ER, p. 1A.1-5, beginning January 1973, Public Service Company of Oklahoma eliminated all promotional marketing activities. A moderate program of consumer information and conservation of energy advertising was instituted. The following is a partial list of methods used and topics considered:

Advertising. How to Keep Your Cool; Reductions; 10 Ways to Save on Your Electric Bill; Build Energy Conservation into Today's Homes.

Bill Enclosures. Electricity Goes Underground; How to Read Your Meter; How to Avoid Unnecessary Service Calls on Your Electric Appliances; How to Take the Bite Out of Your Winter Electric Bill; How to Take the Bite Out of Summer Cooling Costs; Before You Buy - Information About Purchasing Appliances.

Consumer Consultant Programs - Students and Adults. Stretching the Food Dollar - Wise Meat Buying; Stretching the Food Dollar - Wise Storing and Cooking of Meats; Using Every Watt Wisely - Heating and Cooling; Using Every Watt Wisely - Major Appliances; Wise Use and Care - Small Appliances.

Pamphlets. Wise Meat Buying; Wise Meat Storing and Cooling; Energy Wise Tips for Using Your Electric Range; Wise Appliance Use Pays Off; Before You Buy (tips on purchasing appliances).

Considering the combined impact of the programs discussed above, the staff feels that there is no conclusive measure of the degree to which these programs will impact projected demand.

8.2.4.3 Change in Utility Rates and Structures

The Federal Power Commission regulates the transmission and sale of energy in interstate commerce. The Oklahoma Corporation Commission regulates the intrastate rates that PSO charges, and Associated and Western are nonprofit organizations.

Economic theory indicates that implementation of substantial revisions in rate levels and rate structure, such as inversion of rates, time-of-day metering, or peak-load pricing, will change the pattern and growth of demand for electricity. Table 8.4 shows the energy and adjusted revenue per residential customer for PSO. Both of these quantities rose each year from 1960 to 1970, but the average adjusted price fell from 5.3 cents per kWh in 1960 to 3 cents per kWh in 1970. Since 1970 the adjusted revenue per residential customer has fallen (1971), risen (1972), and fallen (1973, 1974) while energy per residential customer has increased each year. Insufficient knowledge is available on the separate impact of price on sales and on whether increasing prices would have the reverse impact of decreasing price in order to formulate a judgment on the degree to which increasing rates would dampen sales. Neither adequate data nor studies exist that would support a conclusion that such price and rate structure changes would so reduce the projected need for power in the applicant's service area in the next several years as to make unnecessary the construction and operation of the Black Fox Station. The body of literature on quantitative demand analysis does not address the effects of rate structure changes per se. Some authors have discussed the potential consequences in theoretical terms of rate structure changes upon demand for electricity. However, a review of the literature on this subject does not reveal a forecasting methodology commonly agreed upon as having acceptable accuracy that indicates how a given change in rate structure would affect the date at which the generating capacity represented by the Black Fox Station will be required.

8.2.4.4 Load Shedding, Load Staggering, and Interruptible Load Contracts to Reduce Peak Demand

In determining the possibility of using load shedding as a technique that might eliminate the need for additional electricity from the station, it is first important to distinguish among load curtailment and load relief measures and load shedding.

Load curtailment measures include all methods of reducing demands on electric utility systems during periods when capacity is inadequate, for whatever reason, to serve load. A list of load curtailment measures follows:

- Curtailment of all nonessential electric power usage at all utility-owned power plants and office facilities.

- Discontinuing service to contractually interruptible loads, the attractiveness of which depends upon the rate incentive offered and the specification of the number and duration of the interruptions that may also be specified in the contract.

- Voltage reduction. (Generally, voltage levels may be reduced 3 to 5% but in exceptional situations an 8% reduction may be effected.)

- Voluntary curtailment of nonessential loads of large commercial and industrial customers.

These methods of decreasing demand during emergency periods have been used successfully by many utilities. The participants do not have and do not anticipate having interruptible load contracts. Those utilities that do have interruptible load do not use it to reduce the annual peak demands of energy requirements in power planning studies.

For interruptible load contracts to be effective in system planning, the load reduction must be large enough to be effective in system stability planning. Thus, this type of contract is primarily related to industrial customers. The acceptability of interruptible load contracts to industrial customers depends upon balancing the potential economic loss resulting from unannounced interruptions against the saving resulting from the reduced price of electricity. If the frequency or duration of interruptions increases as a result of insufficient installed capacity, the customer becomes more inclined to convert to a normal industrial load contract. In any case, interruptible load contracts are more likely to obviate the need for peaking units rather than base units such as Black Fox Station.

Load shedding is an emergency measure to prevent system collapse when peak demand placed upon the system is greater than the system is capable of providing. This measure is usually not taken until all other measures are exhausted. The Federal Power Commission's report on the major load shedding that occurred during the Northeast power failure of November 9 and 10, 1965, indicates that reliability of service of the electrical distribution systems should be given more emphasis, even with the additional costs.[8] This report identified several areas that are seriously affected by loss of power, such as elevators, traffic lights, subway lighting, and

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prison and communication facilities. It is the serious impact on areas such as these that results in load shedding as only a temporary method to overcome a shortage of generating capacity during an emergency.

Load staggering has also been considered by the staff as a possible conservation measure. Basically, this alternative involves shifting the work hours of industrial or commercial firms to avoid diurnal or weekday peaks. However, it appears unlikely that rates could be adjusted to the degree necessary to cause substantial changes in work patterns. Thus, this practice could not be relied upon to obviate the need for Black Fox Station.

#### 8.2.4.5 Factors Affecting the Efficient Utilization of Electrical Energy

During the past two years, much of industry, the Federal government, and many state and local governments have made the promotion of energy conservation a priority program. The U. S. Department of Commerce has developed a department-wide effort to (1) encourage business firms to conserve energy in the operation of their own processes and building; (2) encourage the manufacture and marketing of more energy-efficient products; and (3) encourage businessmen to disseminate information on energy conservation. The National Bureau of Standards has been given a leading role in promoting the development and implementation of energy-saving standards. Programs include voluntary labeling of household appliances; research, development and education with respect to energy conservation in building; efficient use of energy in industrial processes; and improved energy efficiency in environmental control processes. Although considerable efficiencies in use of electricity have already been gained and although further efficiencies will be realized, any present estimates of the magnitude of electricity savings to be realized over time must be treated as tentative and subject to continual reassessment.

Considerable efficiency can be achieved in space conditioning by improved insulation and the use of building materials with improved insulating properties, as well as by using equipment that transfers or stores excess heat or cold. For example, the seven-story Federal Office Building to be built in Manchester, New Hampshire, illustrates the potential for energy conservation in future commercial building using existing technology. For this particular building, energy savings are anticipated to be a minimum of 20 to 25% over a conventionally designed building in the same location. Heat savings alone are expected to be 44% because of better insulated walls, less window areas, use of efficient heating and heat storage equipment, and the use of solar collectors on the roof.

In 1971, FHA established new insulation standards that would reduce average residential heating losses by one-third. Studies have shown that it is possible to gain even greater reductions in heat loss through improved insulation at costs that are economical over a period of years.[9] Improved insulation not only conserves energy in winter, but also reduces the air-conditioning burden in the summer.

The use of solar space and water heating by Sooners could reduce the energy demanded of the applicants, though probably not total capacity because back-up heating systems would be required during prolonged cloudy weather. The staff believes it unlikely that many Oklahomans will retro-fit their homes with solar heating because of the large cost involved. The staff further believes that at most only a small fraction of new buildings will be designed for solar heat because of the general conservatism of the construction industry and the higher than usual front-end cost entailed by solar heat.

Lighting, which has accounted for about 24% of all electricity sold nationally, is another area where savings are being realized. Many experts believe recommended lighting levels in typical commercial buildings have been excessive.[10] It has been calculated that adequate illumination in commercial buildings can be achieved at 50% of current levels through various design and operational changes. Another study indicated that if all households in 1970 had changed to fluorescent from incandescent lighting, the residential use of electricity for lighting would have been reduced approximately 2.5%.[11] However, because the majority of residential lighting occurs in off-peak hours, the reduction of peak demand would be less than 1%.

The potential for greater efficiency in household appliances is well recognized. The National Bureau of Standards is working with an industrial task force from the Association of Home Appliance Manufacturers in a voluntary labeling program that would provide consumers with energy consumption and efficiency values for each appliance and educate consumers on how to use this information. Room air conditioners are the first to be labeled. The next two categories of that house appliances that are to be labeled are refrigerators and refrigerator/freezers and hot water heaters.

The importance of energy-efficiency labeling of appliances is that it will allow the consumer to select the most energy-efficient appliance. A recent study entitled "The Room Air Conditioner as an Energy Consumer" has estimated that an improvement in average efficiency from six to ten Btu/watt-hr could hypothetically save electric utilities almost 58,000 MW in 1980.[12] Air conditioners that are more energy-efficient require a combination of increased heat-exchanger size and higher-efficiency compressors, resulting in higher initial cost. The consumer must be convinced that it is profitable for him in the long term to purchase the more expensive machine. Today, however, there is a high degree of uncertainty in predicting to what extent consumers will actually purchase these more expensive appliances. In addition, selection of central air conditioning by developers and many homeowners has historically been based on minimizing front-end costs subject to meeting local building codes.

Considerable opportunity for conservation of electricity exists in industry in addition to lighting and air conditioning efficiency already mentioned. Electric motors should be turned off when not in use and motors should be carefully sized according to the work they are to perform. Small savings can be realized by de-energizing transformers whenever possible. Fuel requirements from vacuum furnaces can be reduced by 75% if local direct combustion low-quality heat rather than high-quality electrical resistance heating is employed.[13]

As experience is accumulated, a better forecast can be made of the extent to which savings from these kinds of conservation measures will be implemented. In addition, the staff is aware that the National Institute of Occupational Safety and Health has recommended heat-stress standards to the Occupational Safety and Health Administration which, if adopted, would require a significant number of employers to air condition their plants.[14] This possible requirement, coupled with the above, makes any significant reduction in the future peak demand for electricity due to this conservation of energy measure highly uncertain at this time.

8.2.4.6 Consumer Substitution of Electricity for Scarce Fuels

Although conservation measures are rather quickly adopted in a "crisis" situation, the consumer's substitution of electrical energy for fuels such as oil or gas takes several years or more to result in a substantial upward demand for power because of its reaction to capital investments that use electricity.

Substitution of electricity for scarce energy sources will likely accelerate in the applicant's service area because of the uncertainty of oil and gas supplies and the outlook for higher prices for these fuels with respect to the price of electricity produced from nuclear plants.

For instance, in the PSO service area approximately 9% of residences were electrically heated. On the other hand, 59% (1974) and 27% (1975) of the new residential connections had resistive space heating (ER Supp. 1). At present, PSO estimates 75% of its customers have air conditioning. The advent of electric automobiles and other new uses of electricity cannot be discounted and are not now quantified in projecting need for power because of their high degree of uncertainty. The staff's evaluation is that substitution effects will be, to some substantial degree, offset by savings from conservation of energy techniques.

A second kind of substitution that is relatively important in considering the need to add the proposed nuclear plant to this system is the desirability of adding nuclear capacity to reduce fuel consumed by gas- and oil-fired units now forming a large part of the system. This, in turn, will increase the availability of these more versatile fuel resources for which there is no available substitute.

8.3 POWER SUPPLY

8.3.1 System Capability and Reserve

The reserve requirements of individual power systems and power pools are commonly based on one of the three following standards: (1) a percentage of peak load, (2) the ability to withstand the loss of its largest, or simultaneous loss of its two largest generating stations, or (3) an assessment of the probability of an outage that would force load shedding. Implementation of the third standard is the most complex because it requires an extensive actuarial and engineering effort to calculate the needed probability. These probabilities are themselves an insufficient basis for a decision on whether to seek a reliability compatible with an outage every five years, every ten years, or some other level. For this reason, the first and second criteria have been widely used by utilities in the past. At present, industry-wide discussions are taking place and uncertainty exists as to the most efficacious and cost-effective way to set future reliability standards. The staff believes that PSO and Associated are in line with current industry practice and are justified in expressing their reserve requirements in terms of a percentage of peak load.

At present, PSO generates almost all of its electrical energy by burning natural gas. Table 8.11 lists characteristic parameters and expected ratings and deratings of PSO's generating stations. As indicated by this table, PSO does not plan to derate a significant amount of capabity in the foreseeable future. It does plan to add Northeastern 3 and 4, each of which is a 450-MW coal-burning station. PSO currently

Table 8.11. PSO System Summer Generating Capability (megawatts)
1970-74 Actual--1975-90 Forecast

| Unit Name | Year | Capacity Factor Ranges[a] | | Base Loaded[b] | | | Cycle Loaded[b] | Peaking[b] Combustion | | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Before BFS | After BFS | Gas | Coal | Nuclear | | Turbine | Diesel | |
| System as of January 1, 1970 | | | | | | | | | | |
| Lawton 1 | | | | | | | 5 | | | |
| Lawton 2 | | | | | | | 2 | | | |
| Lawton 4 | | | | | | | 5 | | | |
| Lawton 5 | | | | | | | 14 | | | |
| Southwestern 1 | | c/-4 | c/ | | | | 80 | | | |
| Southwestern 2 | | 1-10 | c/-1 | | | | 80 | | | |
| Southwestern 3 | | 27-74 | 3-16 | 320 | | | | | | |
| Tulsa 1 | | c/-1 | c/ | | | | 30 | | | |
| Tulsa 2 | | 7-51 | 1-4 | 178 | | | | | | |
| Tulsa 3--total | | 1-7 | c/-1 | | | | 105 | | | |
| Tulsa 4 | | 4-39 | 1-2 | 178 | | | | | | |
| Weleetka 1 | | c/-1 | | | | | 24 | | | |
| Weleetka 2 | | c/-1 | | | | | 24 | | | |
| Weleetka 3 | | c/-1 | | | | | 30 | | | |
| Northeastern 1 | | 2-33 | c/-1 | 170 | | | | | | |
| Small peakers | | | | | | | | | 23 | |
| TOTAL | January 1, 1970 | | | 846 | | | 399 | | 23 | 1268 |
| Additions and (Retirements) after January 1, 1970 Actual to April 1, 1975 | | | | | | | | | | |
| Northeastern 2 | 1970 | 69-87 | 40-62 | 470 | | | | | | |
| TOTAL | 1970 | | | 1316 | | | 399 | | 23 | 1738 |
| Lawton 1, 2, and 4 | 1972 | | | | | | (12) | | | |
| TOTAL | 1972 | | | 1316 | | | 387 | | 23 | 1726 |
| Tulsa 3-B | 1973 | | | | | | (6) | | | |
| Southwestern 3 | | | | (10) | | | | | | |
| Lawton 5 | | | | | | | (14) | | | |
| TOTAL | 1973 | | | 1306 | | | 367 | | 23 | 1696 |
| Comanche | 1974 | 36-81 | 4-19 | 216 | | | | | | |
| Riverside 1 | | 68-86 | 12-57 | 340 | | | | | | |
| TOTAL | 1974 | | | 1862 | | | 367 | | 23 | 2252 |

Table 8.11. Continued

| Unit Name | Year | Capacity Factor Ranges[a] Before BFS | Capacity Factor Ranges[a] After BFS | Base Loaded[b] Gas | Base Loaded[b] Coal | Base Loaded[b] Nuclear | Cycle Loaded[b] | Peaking Combustion[b] Turbine | Peaking Combustion[b] Diesel | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Forecast | | | | | | |
| Weleetka 4 | 1975 | c/-1 | c/ | | | | | 60 | | |
| Riverside 1 | | | | 110 | | | | | | |
| TOTAL | 1975 | | | 1972 | | | 367 | 60 | 23 | 2422 |
| Weleetka 5 | 1976 | c/-2 | c/ | | | | | 60 | | |
| Weleetka 6 | | c/-2 | c/ | | | | | 60 | | |
| Riverside 2 | | 70-84 | 29-73 | 450 | | | | | | |
| TOTAL | 1976 | | | 2422 | | | 367 | 180 | 23 | 2992 |
| Riverside | 1977 | | | | | | | | 3 | |
| TOTAL | 1977 | | | 2422 | | | 367 | 180 | 26 | 2995 |
| Northeastern 3 | 1979 | 67-82 | 56-78 | | 450 | | | | | |
| TOTAL | 1979 | | | 2422 | 450 | | 367 | 180 | 26 | 3445 |
| Northeastern 4 | 1980 | 65-80 | 70-78 | | 450 | | | | | |
| TOTAL | 1980 | | | 2422 | 900 | | 367 | 180 | 26 | 3895 |
| Undertermined | 1982 | 51 | 48-61 | | | | | | | |
| TOTAL | 1982 | | | 2422 | 900 | | 367 | 180 | 26 | 3895 |
| Black Fox 1 | 1983 | | 54-67 | | | 700[d] | | | | |
| Weleetka 1, 2, and 3 | | | | | | | (78) | | | |
| TOTAL | 1983 | | | 2422 | 900 | 700 | 289 | 180 | 26 | 4517 |
| Black Fox 2 | 1985 | | 56-65 | | | 700[e] | | | | |
| TOTAL | 1985 | | | 2422 | 900 | 1400 | 289 | 180 | 26 | 5217 |
| Undetermined | 1987 | | 65-77 | | 450 | | | | | |
| TOTAL | 1987 | | | 2422 | 1350 | 1400 | 289 | 180 | 26 | 5667 |
| Undetermined | 1988 | | 65-77 | | 450 | | | | | |
| TOTAL | 1988 | | | 2422 | 1800 | 1400 | 289 | 180 | 26 | 6117 |

Table 8.11. Continued

| Unit Name | Year | Capacity Factor Ranges[a] | | Base Loaded[b] | | | Cycle Loaded[b] | Peaking[b] Combustion | | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Before BFS | After BFS | Gas | Coal | Nuclear | | Turbine | Diesel | |
| Undetermined | 1989 | | 54-57 | | | 750[f] | | | | |
| TOTAL | 1989 | | | 2422 | 1800 | 2150 | 289 | 180 | 26 | 6867 |
| Undetermined | 1990 | | 65 | | 260 | | | | | |
| TOTAL | 1990 | | | 2422 | 2060 | 2150 | 289 | 180 | 26 | 7127 |

[a]The range is estimated for the years 1975-82 and for the years 1986-90. Capacity factors expressed as percentages.

[b]These loading types are as of commission date of the unit or as of April 1975.

[c]Less than one percent.

[d]PSO's portion of Black Fox Unit 1.

[e]PSO's portion of Black Fox Unit 2.

[f]PSO's portion of a 1150-MW nuclear unit.

Modified from ER, Table 1.1-7a, and Supplement 4.

m.ntains a reserve capacity of 16% of its peak demand by supplementing its own capacity with purchases from other utilities (e.g., GRDA). Table 8.12 shows PSO's planned purchases and sales during future peaks.

Like PSO, Western presently burns natural gas to generate most of its electricity. Table 8.13 lists characteristic parameters and expected ratings of Western's generating equipment. However, at present eight of its distribution co-ops receive power by purchase. Beginning July 1, 1977, Western plans to serve part of this load by purchasing 260 MW of hydroelectric peaking capacity from the Southwestern Power Administration. As indicated by Table 8.13, Western plans to add 315 MW of gas-burning baseload capacity in 1977 and 350 MW of coal-burning baseload capacity in 1981. Western currently maintains a reserve capacity of at least 15% of its peak load, and Table 8.14 shows its planned purchases and sales during the peak.

PSO's planning for the 1980s is predicated on a 20% reserve margin in order to allow for forced outages during the initial operational period of the new units to be brought on line. Since the staff believes that the long-term load growth will be less than that which PSO forecasts, the addition of Black Fox Station could be deferred at least three years until 1985 (see Table 8.15) if natural gas were to remain available as a boiler fuel for baseload operation.

However, it is precisely the question of the availability of natural gas that has prompted PSO and Western to seek a mix of baseload capacity that burns coal and uranium. (ER p. 9.1-2) It is generally believed that supplies of natural gas will dwindle after 1985.[3,15,16] The installation of non-gas burning baseload capacity will allow the natural gas that would have been used to produce electricity to be used for other purposes, such as space heating, cooking, grain drying and the production of industrial organic chemicals.* Thus, the prompt construction of Black Fox Station is compatible with a national policy to husband natural gas for purposes other than electrical generation.** Because of this, the staff believes that the installation of coal or nuclear baseload capacity is timely. It should also be noted that the FEA is effectively forbidding the construction of new gas-burning baseload capacity and that the Senate is considering a bill (S.B. 1777) that would forbid the burning of natural gas at extant baseload plants. Figure 8.5 and Table 8.16 show both PSO's planned additions of coal and nuclear capacity and the forecasts of average hourly load that have already been discussed.

Associated generates all its baseload by burning coal. Table 8.17 lists characteristic parameters and planned ratings of Associated's generating stations. As indicated by this table, Associated does not plan to derate any capacity. It does plan to add New Madrid II, a 600-MW coal-fired station, and another 600-MW coal-fired station that is as yet unnamed. Associated currently maintains a reserve capacity of 15% of its peak demand by supplementing its own capacity with purchases from other utilities. Table 8.18 shows Associated's planned purchases and sales during future peaks. Since it believes that the long-term load growth will be less than that which Associated forecasts, the staff feels there will be ample capacity for reserve.

### 8.3.2 Regional Capability and Reserve

PSO, Western and five other utilities constitute Group B of the Southwest Power Pool (SPP). By mutual agreement of SPP's members, each such group must plan for and maintain a reserve capacity of at least 15% of the peak demand made on it. Table 8.19 shows the capacity and peak demand that Group B forecasts for its future. Tables 8.20 and 8.21 show the capacity and demand that the SPP forecasts for its future summers and winters. These tables clearly indicate that despite the planned addition of capacity, the SPP still expects to have to import capacity during the summer. On the other hand, the SPP plans to export capacity during the winter months. Both planned capacity installations and estimated loads are less than those forecasted in the spring of 1974. When studying such forecasts it is well to recall the SPP's Load Forecast/Reserve Capacity Subcommittee's remark that "... it is obvious that the projections are subject to unpredictable factors such as licensing delays, regulatory decisions, labor and productivity disputes, weather conditions and rapidly changing economic conditions."[17] Two of the most important of the uncertain economic conditions are the prices and ava ility of natural gas and imported oil.

Associated is a member of both the SPP and Mid-American Interconnection Network (MAIN). However, it is through MAIN that Associated reports to the FPC. Table 8.22 shows MAIN's forecast for its future capacity. Like the SPP, MAIN expects to import power at the time of its system peak (see Table 8.23).

## 8.4 SUMMARY

The staff has studied various projections and concludes that 1985 is the earliest probable year in which PSO wi l need new capacity to meet i growing peak load. However, the staff believes that there is a need to husband the nation's su pply of natural gas for purposes other than electrical generation. This need can be fulfilled by the prompt construction of non-gas burning

* Gas burning capacity will still be available for occasional use during periods of peak demand.

** The staff believes that it is impractical to convert a gas burning facility to a coal burning one.

Table 8.12. Net[a] Power Exchanges (MWe) at Time of System Peak as Forecasted by PSO

| Year | Net Firm | Net Non-Firm | Net Power Exchange |
|---|---|---|---|
| Actual | | | |
| 1965 | 182 | 42 | 224 |
| 1966 | 300 | 8 | 308 |
| 1967 | 371 | 4 | 375 |
| 1968 | 328 | 112 | 440 |
| 1969 | 280 | (26) | 254 |
| 1970 | 63 | (68) | (5) |
| 1971 | 209 | 6 | 215 |
| 1972 | 334 | 24 | 358 |
| 1973 | 404 | 3 | 407 |
| 1974 | 416 | (266) | 150 |
| Forecast | | | |
| 1975 | 444 | (211) | 233 |
| 1976 | 458 | (709) | (251) |
| 1977 | 310 | (396) | (86) |
| 1978 | 310 | (171) | 139 |
| 1979 | 310 | (336) | (26) |
| 1980 | 310 | (536) | (226) |
| 1981 | 310 | (236) | 74 |
| 1982 | 310 | (236) | 74 |
| 1983 | 310 | (436) | (126) |
| 1984 | 310 | (236) | 74 |
| 1985 | 310 | (436) | (126) |
| 1986 | 310 | (236) | 74 |
| 1987 | 310 | (236) | 74 |
| 1988 | 310 | (136) | 174 |
| 1989 | 310 | (136) | 174 |
| 1990 | 310 | (136) | 174 |

[a]Net taken to be the sum of the purchases and sales with the sign convention that a purchase is positive and sale is considered (negative).

From ER, Table 1.1-5a.

718 352

719 149

Table 8.13. Western System Summer Generating Capability
megawatts
1970-1974 Actual--1975-1990 Forecast

| Unit Name | Year | Capacity Factor Ranges: Before BFS | Capacity Factor Ranges: After BFS | Base Loaded: Gas | Base Loaded: Coal | Base Loaded: Nuclear | Cycle Loaded | Peaking Combustion Turbine | Diesel | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Anadarko 1 | | | 0 | | | | 15 | | | |
| Anadarko 2 | | | 0 | | | | 16 | | | |
| Anadarko 3 | | | 0 | 47 | | | | | | |
| Mooreland 1 | | | 0 | 55 | | | | | | |
| Mooreland 2 | | 15-20 | 0-5 | 143 | | | | | | |
| Woodward Diesel | | | | | | | | | 4 | |
| Total, Jan 1, 1970 | | | | 245 | | | 31 | | 4 | 280 |
| Mooreland 3 | 1975 | 15-20 | 0-5 | 144 | | | | | | |
| Total, 1975 | | | | 389 | | | 31 | | 4 | 424 |
| Anadarko 4 | 1977 | 70-80 | 0-10 | 105 | | | | | | |
| Anadarko 5 | 1977 | 70-80 | 0-10 | 105 | | | | | | |
| Anadarko 6 | 1977 | 70-80 | 0-10 | 105 | | | | | | |
| Total, 1977 | | | | 704 | | | 31 | | 4 | 739 |
| Unnamed | 1981 | 70-80 | 70-80 | | 350 | | | | | |
| Total, 1981 | | | | 704 | 350 | | 31 | | 4 | 1089 |
| Black Fox 1 | 1983 | | 70-80 | | | 200 | | | | |
| Total, 1983 | | | | 704 | 350 | 200 | 31 | | 4 | 1289 |
| Black Fox 2 | 1985 | | 70-80 | | | 200 | | | | |
| Total, 1985 | | | | 704 | 350 | 400 | 31 | | 4 | 1489 |
| Unnamed | 1986 | | 70-80 | | 350 | | | | | |
| Total, 1986 | | | | 704 | 700 | 400 | 31 | | 4 | 1839 |
| Unnamed | 1988 | | 70-80 | | 350 | | | | | |
| Total, 1988 | | | | 704 | 1050 | 400 | 31 | | 4 | 2189 |
| Unnamed | 1990 | | 70-80 | | 350 | | | | | |
| Total, 1990 | | | | 704 | 1400 | 400 | 31 | | 4 | 2539 |

Table 8.14. Western Net[a] Power Exchanges at Time of System Peak, megawatts

| Year | Net Firm | Net Non-Firm | Net Power Exchange |
|---|---|---|---|
| Actual | | | |
| 1965 | (5) | 0 | (5) |
| 1966 | 5 | 0 | 5 |
| 1967 | 28 | (13) | 15 |
| 1968 | 0 | 0 | 0 |
| 1969 | (60) | (20) | (80) |
| 1970 | (19) | 0 | (19) |
| 1971 | 41 | 0 | 41 |
| 1972 | (1) | 0 | (1) |
| 1973 | (139) | (25) | (164) |
| 1974 | (181) | (25) | (206) |
| Forecast | | | |
| 1975 | 190 | 0 | 190 |
| 1976 | 231 | 0 | 231 |
| 1977 | 271 | 0 | 271 |
| 1978 | 260 | 0 | 260 |
| 1979 | 260 | 0 | 260 |
| 1980 | 260 | 0 | 260 |
| 1981 | 260 | 0 | 260 |
| 1982 | 260 | 0 | 260 |
| 1983 | 260 | 0 | 260 |
| 1984 | 260 | 0 | 260 |
| 1985 | 260 | 0 | 260 |
| 1986 | 260 | 0 | 260 |
| 1987 | 260 | 0 | 260 |
| 1988 | 260 | 0 | 260 |
| 1989 | 260 | 0 | 260 |
| 1990 | 260 | 0 | 260 |

[a]Net taken to the sum of the purchases and sales with the sign convention that a purchase is positive and sale is considered (negative).

Table 8.15. PSO Maximum Hourly Load and Reserve Margins

| Year | Maximum Hourly Load, MWe: PSO Forecast | Maximum Hourly Load, MWe: Staff's Upper Forecast | Maximum Hourly Load, MWe: Staff's Lower Forecast | PSO's Capacity Forecast, MWe | Reserve Margins,[a] %: PSO Forecast | Reserve Margins,[a] %: Staff's Lower Forecast[b] | Reserve Margins,[a] %: Staff's Upper Forecast[c] |
|---|---|---|---|---|---|---|---|
| | 5248 | 4354 | 3677 | 5667 = 4267 + 7[illegible]0[d] + 700[e] | 10.0 | 34.3 = -0.3 + 17.3[d] + 17.3[e] | 6[illegible].4 = 19.7 + 20.9[d] + 20.9[e] |
| | 4882 | 4092 | 3505 | 5217 = 3817 700[d] + 700[e] | 8.9 | 31.7 = -5.3 + 18.5[d] + 18.5[e] | 55.9 = 1.2 + 27.3[d] + 27.3[e] |
| 1985 | 4550 | 3846 | 3341 | 5217 = 3817 + 700[d] + 700[e] | 17.5 | 35.2 = -4.4 + 19.8[d] + 19.8[e] | 57.7 = 11.5 + 23.1[d] + 23.1[e] |
| | 4237 | 3615 | 3185 | 4517 = 3817 + 700 | 9.0 | 29.5 = 8.4 + 21.1[d] | 48.9 = 24.6 + 24.3[d] |
| | 3940 | 3397 | 3037 | 4517 = 3817 + 700[d] | 17.9 | 32.2 = 9.5 + 22.7[d] | 49.7 = 24.0 + 25.7[d] |
| | 3661 | 3193 | 2895 | 3895 | 9.2 | 26.9 | 41.5 |
| | 3401 | 3001 | 2759 | 3895 | 18.4 | 36.0 | 49.4 |
| 1980 | 3158 | 2824 | 2631 | 3859 | 17.9 | 33.6 | 44.7 |
| | 2931 | 2654 | 2508 | 3445 | 18.6 | 32.6 | 41.4 |
| | 2719 | 2495 | 2391 | 2995 | 17.2 | 29.2 | 35.7 |
| | 2521 | 2345 | 2279 | 2995 | 17.5 | 27.7 | 32.0 |
| | 2309 | 2204 | 2177 | 2992 | 18.2 | 30.8 | 32.8 |
| 1975 | 2071[f] | | | 2422 | | 16.9 | |

[a]The reserve margin is calculated from the formula:

$$\text{Reserve Margin} = \frac{[\text{Capacity + Net Nonfirm Purchases}] - [\text{Maximum Hourly Load - Net Firm Purchases}]}{[\text{Maximum Hourly Load - Net Firm Purchases}]}$$

[b]The staff's lower forecast for reserve margin is derived from its upper forecast for maximum hourly load.

[c]The staff's upper forecast for reserve margin is derived from its lower forecast for maximum hourly load.

[d]BFS I.

[e]BFS II.

[f]Historical.

Table 8.16. PSO Average Hourly Load and Non-Gas Baseload Capacity

| | Average Hourly Load, MWe-h/h | | | |
|---|---|---|---|---|
| Year | PSO Forecast | Staff's Upper Forecast | Staff's Lower Forecast | Non-Gas Baseload Capacity, MWe |
| | 2362 | 2204 | 1859 | 2750 = 1350[a] + 700[b] + 700[c] |
| | 2197 | 2071 | 1772 | 2300 = 900[a] + 700[b] + 700[c] |
| 1985 | 2050 | 1947 | 1689 | 2300 = 900[a] + 700[b] + 700[c] |
| | 1911 | 1830 | 1610 | 1600 = 900[a] + 700[b] |
| | 1800 | 1720 | 1535 | 1600 = 900[a] + 700[b] |
| | 1686 | 1616 | 1463 | 900[a] |
| | 1596 | 1519 | 1395 | 900[a] |
| 1980 | 1507 | 1427 | 1330 | 900[a] |
| | 1413 | 1342 | 1268 | 450[a] |
| | 1325 | 1261 | 1208 | 0 |
| | 1263 | 1185 | 1152 | 0 |
| | 1198 | 1114 | 1098 | 0 |
| 1975 (actual) | 1047 | | | 0 |

[a]Coal-fired capacity.

[b]BFS I.

[c]BFS II.

Table 8.17. Associated System Summer Generating Capacity (megawatts)
1970-74 Actual--1975-90 Forecast

| Unit Name | Year | Capacity Factor | | Base Loaded | | Cycle Loaded | Peaking Combustion | | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|
| | | Before BFS | After BFS | Coal | Nuclear | | Turbine | Diesel | |
| Green Forest | | 30-40 | 25-35 | | | | | 10 | |
| South River 1 | | 35-45 | 25-35 | | | 8 | | | |
| South River 2 | | 35-45 | 25-35 | | | 8 | | | |
| South River 3, 4, and 5 | | 30-40 | 20-30 | | | | | 6 | |
| Mo. City 1 | | 40-50 | 25-40 | | | 21 | | | |
| Mo. City 2 | | 40-50 | 25-40 | | | 21 | | | |
| Chamois 1 | | 45-55 | 30-40 | | | 18 | | | |
| Chamois 2 | | 45-55 | 30-45 | | | 50 | | | |
| Thomas Hill 1 | | 80-90 | 80-90 | 180 | | | | | |
| Thomas Hill 2 | | 80-90 | 80-90 | 303 | | | | | |
| TOTAL | January 1, 1970 | | | 483 | | 126 | | 16 | 625 |
| New Madrid 1 | 1972 | 75-80 | 75-80 | 600 | | | | | |
| TOTAL | 1972 | | | 1083 | | 126 | | 16 | 1225 |
| New Madrid 2 | 1977 | 60-70 | 60-70 | 600 | | | | | |
| TOTAL | 1977 | | | 1683 | | 126 | | 16 | 1825 |
| Unnamed | 1980 | 5-30 | 10-15 | | | | 60 | | |
| TOTAL | 1980 | | | 1683 | | 126 | 60 | 16 | 1885 |
| Unnamed | 1982 | 30-50 | 40-55 | 600 | | | | | |
| TOTAL | 1982 | | | 2283 | | 126 | 60 | 16 | 2485 |
| Black Fox 1 | 1983 | | 55-80 | | 250 | | | | |
| Unnamed | 1983 | | 10-15 | | | | 38 | | |
| TOTAL | 1983 | | | 2283 | 250 | 126 | 98 | 16 | 2826 |
| Unnamed | 1984 | | 25-40 | | | 600 | | | |
| TOTAL | 1984 | | | 2283 | 250 | 726 | 98 | 16 | 3426 |
| Black Fox 2 | 1985 | | 60-80 | | 250 | | | | |
| TOTAL | 1985 | | | 2283 | 500 | 726 | 98 | 16 | 3729 |

Table 8.17. Continued

| Unit Name | Year | Capacity Factor | | Base Loaded | | Cycle Loaded | Peaking Combustion | | Cumulative Total |
|---|---|---|---|---|---|---|---|---|---|
| | | Before BFS | After BFS | Coal | Nuclear | | Turbine | Diesel | |
| Unnamed | 1986 | | 20-40 | | | 600 | | | |
| TOTAL | 1986 | | | 2283 | 606 | 1326 | 98 | 16 | 4329 |
| Unnamed | 1987 | | 20-40 | | | 600 | | | |
| TOTAL | 1987 | | | 2283 | 606 | 1926 | 98 | 16 | 4929 |
| Unnamed | 1988 | | 20-40 | | | 600 | | | |
| TOTAL | 1988 | | | 2283 | 606 | 2526 | 98 | 16 | 5529 |
| Unnamed | 1989 | | 60-80 | | 1150 | | | | |
| TOTAL | 1989 | | | 2283 | 1756 | 2526 | 98 | 16 | 6679 |
| Unnamed | 1990 | | 10-15 | | | | 200 | | |
| TOTAL | 1990 | | | 2283 | 1756 | 2526 | 298 | 16 | 6879 |

Table 8.13. Associated Net[a] Power Exchanges at Time of System Peak (megawatts)

| Year | Net Firm[b] | Net Non-Firm | Net Power Exchange |
|---|---|---|---|
| Actual | | | |
| 1965[c] | -- | -- | -- |
| 1966 | 0 | 40 | 40 |
| 1967 | (105) | 281 | 176 |
| 1968 | (58) | 318 | 260 |
| 1969 | (258) | 367 | 109 |
| 1970 | (194) | 559 | 365 |
| 1971 | (176) | 393 | 217 |
| 1972 | (224) | 156 | (68) |
| 1973 | (175) | 40 | (135) |
| 1974 | (222) | 332 | 110 |
| Forecast | | | |
| 1975 | (173) | 282 | 109 |
| 1976 | (298) | 497 | 199 |
| 1977 | (258) | 272 | 14 |
| 1978 | (250) | 330[d] | 80 |
| 1979 | (250) | 490[d] | 240 |
| 1980 | (250) | 680[e] | 430 |
| 1981 | (250) | 948 | 698 |
| 1982 | (250) | 643 | 393 |
| 1983 | (250) | 680 | 430 |
| 1984 | (250) | 468 | 218 |
| 1985 | (250) | 632 | 382 |
| 1986 | (250) | 520 | 270 |
| 1987 | (250) | 580 | 330 |
| 1988 | (250) | 580 | 330 |
| 1989 | (250) | 580 | 330 |
| 1990 | (250) | 580 | 330 |

[a]Net taken to be the sum of the purchases and sales with the sign convention that a purchase is positive and a sale is (negative).

[b]The aluminum company load has been included here as a firm sale.

[c]Associated's system was dispatched by Kansas City Power & Light Company until December 1965. Therefore, purchase and sale information at time of peak is not available for 1965.

[d]It is assumed that Associated will receive the output of Clarence Cannon pumped hydro starting in 1978 and Truman pumped hydro starting in 1979.

[e]Associated anticipates exercising its option under the Missouri Integration Contract and purchase an additional 190 MW of hydro starting in 1980.

718 359

719 156

Table 8.19. Southwest Power Pool Group B Summer Generating Capability (MWe)

| Year | Owning Utility | Base: Gas[a] | Base: Coal | Base: Nuclear | Combined Cycle | Combustion Turbine | Diesel | Conventional Hydro | RPT and Pumped Storage | Unknown | Net Utility Change | Cumulative Yearly Total | Non-Coincident Peak Demand |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Historical | | | | | | | | | | | | | |
| 1970 | GRDA | | | | | 50 | | 198 | 130 | | | 378 | |
| | OGE | 1,636 | | | 245 | 75 | 10 | | | | | 1,966 | |
| | PSO | 1,715 | | | | | 23 | | | | | 1,738 | |
| | SWEP | 1,050 | | | | 48 | | | | | | 1,098 | |
| | SPA | | | | | | | 1468 | | | | 1,468 | |
| | WF | 276 | | | | | 4 | | | | | 280 | |
| | TOTAL | 4,677 | | | 245 | 173 | 37 | 1666 | 130 | | | 6,928 | 5,889 |
| 1971 Net Additions and (Retirements) and Adjustment | GRDA | | | | | | | | 130 | | 130 | | |
| | OGE | 513 | | | | 99 | (1) | | | | 611 | | |
| | SWEP | 509 | | | | | | | | | 509 | | |
| | SPA | | | | | | | 172 | | | 172 | | |
| | TOTAL NET | 1,022 | | | | 99 | (1) | 172 | 130 | | 1422 | | |
| | TOTAL | 5,699 | | | 245 | 272 | 36 | 1838 | 260 | | | 8,350 | 6,299 |
| 1972 | PSO | (12) | | | | | | | | | (12) | | |
| | SPA | | | | | | | 313 | 32 | | 345 | | |
| | TOTAL NET | (12) | | | | | | 313 | 32 | | 333 | | |
| | TOTAL | 5,687 | | | 245 | 272 | 36 | 2151 | 292 | | | 8,683 | 7,027 |
| 1973[b] | OGE | 550 | | | | | | | | | 550 | | |
| | PSO | (30) | | | | | | | | | (30) | | |
| | SPA | | | | | | | 26 | | | 26 | | |
| | SPS[b] | 1,919 | | | 24 | 66 | 1 | | | | 2010 | | |
| | TOTAL NET | 2,439 | | | 24 | 66 | 1 | 26 | | | 2556 | | |
| | TOTAL | 8,126 | | | 269 | 338 | 37 | 2177 | 292 | | | 11,239 | 7,355 |

Table 8.19. Continued

| Year | Owning Utility | Base: Gas[a] | Base: Coal | Base: Nuclear | Combined Cycle | Combustion Turbine | Diesel | Conventional Hydro | RPT and Pumped Storage | Unknown | Net Utility Change | Cumulative Yearly Total | Non-Coincident Peak Demand |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1974 | PSO | 340 | | | 216 | | | | | | 556 | | |
| | SWEP | 360 | | | | (17) | | | | | 343 | | |
| | SPA | | | | | | | 7 | | | 7 | | |
| | WF | 244 | | | | | | | | | 244 | | |
| | SPS | 145 | | | | | | | | | 145 | | |
| | TOTAL NET | 1,089 | | | 216 | (17) | | 7 | | | 1295 | | |
| | TOTAL | 9,215 | | | 485 | 321 | 37 | 2184 | 292 | | | 12,534 | 8,271 |
| Forecast | | | | | | | | | | | | | |
| 1975 | OGE | 550 | | | | | | | | | 550 | | |
| | PSO | 110 | | | | 60 | | | | | 170 | | |
| | WF | 145 | | | | | | | | | 145 | | |
| | SPS | (39) | | | | | | | | | (39) | | |
| | TOTAL NET | 766 | | | | 60 | | | | | 826 | | |
| | TOTAL | 9,981 | | | 485 | 381 | 37 | 2184 | 292 | | | 13,360 | 10,882 |
| 1976 | PSO | 450 | | | | 120 | | | | | 570 | | |
| | SPS | | 317 | | | | | | | | 317 | | |
| | TOTAL NET | 450 | 317 | | | 120 | | | | | 887 | | |
| | TOTAL | 10,431 | 317 | | 485 | 501 | 37 | 2184 | 292 | | | 14,247 | 11,882 |
| 1977 | OGE | | 515 | | | 100 | | | | | 615 | | |
| | PSO | | | | | | 3 | | | | 3 | | |
| | SWEP | | 528 | | | | | | | | 528 | | |
| | WF | | | | 230 | | | | | | 230 | | |
| | TOTAL NET | | 1043 | | 230 | 100 | 3 | | | | 1376 | | |
| | TOTAL | 10,431 | 1360 | | 715 | 601 | 40 | 2184 | 292 | | | 14,247 | 12,749 |

Table 8.19. Continued

| Year | Owning Utility | Base Gas[a] | Base Coal | Base Nuclear | Combined Cycle | Combustion Turbine | Diesel | Conventional Hydro | RPT and Pumped Storage | Unknown | Net Utility Change | Cumulative Yearly Total | Non-Coincident Peak Demand |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1978 | OGE | | 515 | | | | | | | | 515 | | |
| | SWEP/ AECC | | 528 | | | | | | | | 528 | | |
| | SPS | | 318 | | | | | | | | 318 | | |
| | TOTAL NET | | 1361 | | | | | | | | 1361 | | |
| | TOTAL | 10,431 | 2721 | | 715 | 601 | 40 | 2184 | 292 | | | 16,984 | 13,620 |
| 1979 | OGE | | 515 | | | | | | | | 515 | | |
| | PSO | | 450 | | | | | | | | 450 | | |
| | SPA | | | | | | | 27 | 31 | | 58 | | |
| | TOTAL NET | | 965 | | | | | 27 | 31 | | 1023 | | |
| | TOTAL | 10,431 | 3686 | | 715 | 601 | 40 | 2211 | 323 | | | 18,007 | 14,793 |
| 1980 | OGE | | 515 | | | | | | | | 515 | | |
| | PSO | | 450 | | | | | | | | 450 | | |
| | SWEP | | 528 | | | | | | | | 528 | | |
| | WF | | | | 230 | | | | | | 230 | | |
| | SPS | | 318 | | | | | | | | 318 | | |
| | TOTAL NET | | 1181 | | 230 | | | | | | 2041 | | |
| | TOTAL | 10,431 | 5497 | | 945 | 601 | 40 | 2211 | 323 | | | 20,048 | 15,974 |
| 1981 | OGE | | 700 | | | | | | | | 700 | | |
| | SPA | | | | | | | | 160 | | 160 | | |
| | TOTAL NET | | 700 | | | | | | 160 | | 860 | | |
| | TOTAL | 10,431 | 6197 | | 945 | 601 | 40 | 2211 | 483 | | | 20,908 | 17,239 |

Table 8.19. Continued

| Year | Owning Utility | Base Gas[a] | Base Coal | Base Nuclear | Combined Cycle | Combustion Turbine | Diesel | Conventional Hydro | PPT and Pumped Storage | Unknown | Net Utility Change | Cumulative Yearly Total | Non-Coincident Peak Demand |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1982 | OGE | | 700 | | | | | | | | 700 | | |
| | PSO | | 240 | | | | | | | | 240 | | |
| | SWEP | | 528 | | | | | | | | 528 | | |
| | WF | | | | | | | | | 350 | 350 | | |
| | SPS | | 500 | | | | | | | | 500 | | |
| | TOTAL NET | | 1968 | | | | | | | 350 | 2318 | | |
| | TOTAL | 10,431 | 8165 | | 945 | 601 | 40 | 2211 | 483 | 350 | | 23,226 | 18,606 |
| 1983 | OGE | | 700 | | | | | | | | 700 | | |
| | PSO | (78) | | 847[c] | | | | | | | 769 | | |
| | TOTAL NET | (78) | 700 | 847 | | | | | | | 1469 | | |
| | TOTAL | 10,353 | 8865 | 847 | 945 | 601 | 40 | 2211 | 483 | 350 | | 24,695 | 20,037 |
| 1984 | SPS | (23) | | 300 | | | | | | | 277 | | |
| | TOTAL | 10,330 | 8865 | 1147 | 945 | 601 | 40 | 2211 | 483 | 350 | | 24,972 | 21,589 |

[a]Base gas is the total of gas and/or oil-fired fossil steam units as reported in response to FPC Order No. 383-3.

[b]Southwestern Public Service Company joined SPP (Group B).

[c]The remaining portion of PSO's BFS Unit 1 1150 MW after Associated's 303-MW portion was assigned.

From ER, Tables 1.1-8 and 1.1-2a.

Table 8.20. Summer Capability-Load-Margins 1975-1984, Inclusive (net MWe)

| Item | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 |
|---|---|---|---|---|---|---|---|---|---|---|
| Committed capacity | 41,309 | 43,317 | 45,233 | 49,074 | 52,199 | 56,940 | 58,409 | 63,336 | 65,411 | 67,685 |
| Purchases w/o reserves (+) | 270 | 228 | 226 | 226 | 226 | 226 | 226 | 226 | 226 | 226 |
| Sales w/o reserves (-) | 508 | 713 | 588 | 388 | 388 | 388 | 388 | 487 | 487 | 586 |
| Uncommitted capacity (+) | -- | 110 | 449 | 871 | 1,672 | 2,702 | 4,391 | 6,955 | 10,500 | 13,495 |
| Scheduled maintenance[a] (-) | 377 | -- | 246 | -- | -- | -- | -- | -- | -- | -- |
| Total capacity | 40,694 | 42,942 | 45,074 | 49,783 | 53,709 | 59,480 | 62,638 | 70,030 | 75,650 | 80,820 |
| Non-coincidental peak | 34,735 | 37,526 | 41,012 | 44,262 | 47,978 | 51,960 | 55,793 | 60,386 | 65,303 | 70,522 |
| Firm purchases (-) | 1,814 | 1,858 | 1,877 | 1,897 | 1,918 | 1,934 | 1,946 | 1,957 | 1,968 | 1,977 |
| Firm sales (+) | 170 | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Peak load responsibility | 33,091 | 35,668 | 39,135 | 42,365 | 46,060 | 50,026 | 53,847 | 58,429 | 63,335 | 68,545 |
| Margin -MW | 7,603 | 7,274 | 5,939 | 7,418 | 7,649 | 9,454 | 8,791 | 11,601 | 12,315 | 12,275 |
| Margin - % | 22.9 | 20.4 | 15.2 | 17.5 | 16.6 | 18.9 | 16.3 | 19.9 | 19.4 | 17.9 |

[a]First five years only.

From SPP report to the FPC (April 1, 1975) pursuant to Order No. 383-3.

Table 8.21. Winter Capability-Load-Margins 1975-1984, Inclusive (net MW)

| Item | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 | 1983 | 1984 |
|---|---|---|---|---|---|---|---|---|---|---|
| Committed capacity | 41,235 | 42,595 | 44,859 | 49,374 | 52,256 | 56,585 | 58,817 | 64,156 | 65,789 | 68,875 |
| Purchases w/o reserves (+) | 246 | 226 | 226 | 226 | 226 | 226 | 226 | 226 | 226 | 226 |
| Sales w/o reserves (-) | 508 | 713 | 588 | 388 | 388 | 388 | 487 | 487 | 586 | 586 |
| Uncommitted capacity (+) | -- | 110 | 449 | 871 | 1,692 | 2,722 | 4,411 | 7,175 | 10,520 | 13,515 |
| Scheduled maintenance[a] (-) | 4,010 | 4,222 | 4,578 | 5,255 | 5,429 | -- | -- | -- | -- | -- |
| Total capacity | 36,963 | 37,996 | 40,368 | 44,828 | 48,357 | 59,145 | 62,697 | 71,070 | 75,949 | 82,030 |
| Non-coincidental peak | 24,398 | 26,388 | 28,694 | 31,054 | 33,744 | 36,695 | 39,560 | 42,944 | 46,735 | 50,761 |
| Firm purchases (-) | 314 | 358 | 377 | 397 | 418 | 434 | 446 | 457 | 468 | 477 |
| Firm sales (+) | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 | 1,500 |
| Peak load responsibility | 25,584 | 27,530 | 29,817 | 32,157 | 34,826 | 37,761 | 40,614 | 43,987 | 47,767 | 51,784 |
| Margin - MW | 11,379 | 10,466 | 10,551 | 12,671 | 13,531 | 21,384 | 22,[illegible] | 27,083 | 28,182 | 30,246 |
| Margin - % | 44.5 | 38.0 | 35.3 | 39.4 | 38.8 | 56.6 | 5[illegible] | 61.6 | 58.9 | 58.4 |

[a]First five years only

From SPP report to the FPC (April 1, 1975) pursuant to Order No. 383-3.

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Table 8.22. MAIN Summer Generating Capability (MW)

| Year | Oil and Gas | Coal | Nuclear | Combustion Turbine | Diesel | Conventional Hydro | Pumped Storage | Net Change | Cumulative Yearly Total |
|---|---|---|---|---|---|---|---|---|---|
| Pool as of December 31, 1970 | | 22,851 | 1,304 | 2200 | 115 | 570 | 350 | | 27,390 |
| Net Changes | | | | | | | | | |
| 1971 Change | | 46 | (22) | 106 | 0 | 5 | 0 | 135 | |
| Cumulative Total | | 22,897 | 1,282 | 2306 | 115 | 575 | 350 | | 27,525 |
| 1972 Change | | 2,546 | 2,200 | (124) | (15) | 0 | 0 | 4607 | |
| Cumulative Total | | 25,443 | 3,482 | 2182 | 100 | 575 | 350 | | 32,132 |
| 1973 Change | | | 2,175 | 351 | 17 | 0 | 0 | 3713 | |
| Cumulative Total | 2311[a] | 24,302[a] | 5,567 | 2533 | 117 | 575 | 350 | | 35,845 |
| 1974 Change | (103) | (231) | 535 | 102 | (3) | (4) | 0 | 296 | |
| Cumulative Total | 2208 | 24,071 | 6,192 | 2635 | 114 | 571 | 350 | | 36,141 |
| 1975 Change | 84 | 1,152 | 0 | 0 | 0 | 0 | 0 | 1236 | |
| Cumulative Total | 2292 | 25,223 | 6,192 | 2635 | 114 | 571 | 350 | | 37,377 |
| 1976 Change | (51) | 1,815 | 320 | 24 | 0 | 0 | 0 | 2108 | |
| Cumulative Total | 2241 | 27,038 | 6,512 | 2659 | 114 | 571 | 350 | | 39,485 |
| 1977 Change | 500 | 1,350 | 0 | 17 | 0 | 0 | 0 | 1867 | |
| Cumulative Total | 2741 | 28,388 | 6,512 | 2676 | 114 | 571 | 350 | | 41,352 |
| 1978 Change | 1000 | 1,607 | 0 | 500 | 0 | 0 | 0 | 3107 | |
| Cumulative Total | 3741 | 29,995 | 6,512 | 3176 | 114 | 571 | 350 | | 44,459 |
| 1979 Change | 931 | 480 | 1,048 | 827 | 0 | 0 | 0 | 3286 | |
| Cumulative Total | 4672 | 30,475 | 7,560 | 4003 | 114 | 571 | 350 | | 47,745 |
| 1980 Change | 0 | 717 | 1,048 | 400 | 0 | 0 | 0 | 2165 | |
| Cumulative Total | 4672 | 31,192 | 8,608 | 4403 | 114 | 571 | 350 | | 49,910 |
| 1981 Change | 0 | 1,290 | 2,070 | 200 | 0 | 0 | 0 | 3560 | |
| Cumulative Total | 4672 | 32,482 | 10,678 | 4603 | 114 | 571 | 350 | | 53,470 |
| 1982 Change | (285) | 1,630 | 2,240 | 0 | 0 | 0 | 0 | 3585 | |
| Cumulative Total | 4387 | 34,112 | 12,918 | 4603 | 114 | 571 | 350 | | 57,055 |
| 1983 Change | (8) | 780 | 4,260 | 50 | 0 | 0 | 0 | 5082 | |
| Cumulative Total | 4379 | 34,892 | 17,178 | 4653 | 114 | 571 | 350 | | 62,137 |
| 1984 Change | 0 | 630 | 1,850 | 0 | 0 | 0 | 0 | 2480 | |
| Cumulative Total | 4379 | 35,522 | 19,028 | 4653 | 114 | 571 | 350 | | 64,617 |

[a]MAIN did not distinguish between gas-fired or coal-fired generation units in the 1974 report.

From ER, Tables 1.1-9b and 1.1-2b.

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Table 8.23. MAIN Net Power Exchanges at Time of System Peak (MWe)

| Year | Net Firm Purchases | Net Non-Firm Purchases | Net Power Exchange |
|---|---|---|---|
| 1975 | 892 | 1510 | 2402 |
| 1976 | 588 | 1735 | 2323 |
| 1977 | 907 | 1455 | 2362 |
| 1978 | 382 | 1040 | 1422 |
| 1979 | 233 | 1110 | 1343 |
| 1980 | 34 | 1110 | 1144 |
| 1981 | 36 | 1110 | 1146 |
| 1982 | 38 | 1110 | 1148 |
| 1983 | (92) | 798 | 706 |
| 1984 | (89) | 798 | 709 |

Source: ER Table 1.1-66.

baseload capacity such as the proposed Black Fox Station to supply energy to the PSO and Western service areas. The staff believes that the rate of Associated's future growth is uncertain but that it will be less than it has been in the past. However, because of the small size of the portion of BFS that Associated wishes to own, the staff believes this uncertainty can be neglected when assessing the need for Black Fox Station. This station meets the need for reliable baseload operation.

References

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4. "1972 OBERS Projections--Series E," April 1976. (Available from U. S. Government Printing Office, Washington, D. C., Stock numbers 5245-0013 through 5245-0019.)

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13. "Staff Report, A Technical Basis for Energy Conservation," Federal Power Commission, Office of the Chief Engineer, Washington, D. C., April 1974.

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15. R. Gillette, "Oil and Gas Resources: Did USGS Gush Too High?" Science 185:127-130, July 12, 1974.

16. H. T. Franssen, "Towards Project Interdependence: Energy in the Coming Decade," prepared for the Joint Committee on Atomic Energy, United States Congress (74th Congress 1st Session), 1975.

17. Southwest Power Pool report to Federal Power Commission (April 1, 1975) pursuant to Order No. 383-3.

# 9. ALTERNATIVES

## 9.1 ENERGY SOURCES

### 9.1.1 Not Requiring New Generating Capacity

In Section 8, the staff concluded that the earliest year in which PSO could plausibly be expected to need new capacity to meet its growing peak load would be 1985. If PSO's customers make a determined effort to conserve energy, new peaking capacity may not be needed until after 1987. Construction and operation of Black Fox Station at the earliest practicable date, however, would reduce the consumption of natural gas required for generation of electrical energy and thereby mitigate the expected shortage of that fuel. It is to be noted that the FEA has responded to the expected shortage by forbidding the operation of new gas-fired baseload capacity, and the Senate is considering a bill, S. B. 1777, that will require that by January 1, 1979, any electric power plant which utilizes natural gas as its primary boiler fuel (and is not scheduled for retirement prior to January 1, 1985) shall utilize other than natural gas as its primary boiler fuel.

The only baseload fuel PSO currently uses is natural gas (see Table 8.6). PSO has 23 MW of peaking capacity that burns diesel fuel, but this capacity is no substitute for new baseload capacity because of its small size and the fact that diesel fuel is derived from petroleum. Further, there is no hope of PSO's purchasing presently idle coal-fired capacity from another utility because only 7% of the Southwest Power Pool's capacity is coal-fired.

From these considerations, the staff concludes that there are no viable alternatives available to the applicant that do not require the constrution of new generating capacity.

### 9.1.2 Alternatives Requiring New Generating Capacity

#### 9.1.2.1 Noncompetitive Sources

Solar and Wind Power

The U. S. Energy Research and Development Administration (ERDA) has initiated a research and development program that may lead to commercialization of several types of generating plants deriving their energy directly from the sun or indirectly from wind or ocean thermal gradients. However, the ERDA plan is expected to achieve a nationwide level of power production from wind energy by 1985 equivalent to only one or two nuclear units. For the solar alternatives, only small demonstration plants will be achieved prior to 1985. Within the time frame of the need for BFS, neither solar nor wind alternatives are viable.

Geothermal Energy

Geothermal energy is generally thought to be the result of the decay of radioactive elements in the earth's interior. This heat is conducted outward toward the earth's surface, producing a geothermal gradient (avg. 1°F/100 ft).[1] However, in some areas, heat is concentrated in "hot spots" near the surface as a result of magmatic intrusion, volcanic activity, crustal plate movements and associated faults. The heat of the magma (molten rock) is conducted through layers of crystalline rock and in some areas surface water contacting the hot rock produces hot springs, geysers, or fumaroles.

Naturally occurring steam has been used for production of electrical power since 1904 in Italy. Today, geothermal resources are used for generating electric power in Italy, the United States, Japan, Mexico, New Zealand, Russia, and Iceland. However, the total world production in 1973 was only about 1000 megawatts,[2] an amount produced by a single modern power plant unit using conventional fuel. This low level of production is due to difficulties concerning exploration and to difficulties associated with estimating the extent and life of a potential development.[3]

There are four major types of geothermal systems: vapor-dominated, hot water, geopressured reservoir, and hot dry rock systems. Vapor and hot water systems are created naturally when (1) a significant heat source (hot rock, magma) exists near the earth's surface, (2) the heat source is overlain by a permeable formation (aquifer) enabling groundwater to transfer the heat,

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and (3) an impermeable formation caps the aquifer, preventing loss of the hot fluids. Geopressured reservoirs occur where highly porous sands are saturated with high-temperature brines under high pressure. They are located in sedimentary basins that have been subjected to geologic deformation.[4] Hot dry rock is the most common geothermal resource. In principle, hot dry rock can be reached from anywhere on the earth by drilling deep enough (20,000-50,000 feet). Such depths are beyond present drilling capability. However, there are many areas exhibiting above-normal geothermal gradients, indicating hot rock systems relatively near the surface.[4]

Geothermal reservoirs, such as those described above, must meet the following requirements to have appreciable potential for exploitation: (1) relatively high temperature (greater than 150°F, depending on use and processing technology); (2) a depth shallow enough to permit economic drilling; (3) sufficient rock permeability, either natural or induced, to allow the heat-transfer agent (water and/or steam) to flow continuously at a high rate; and (4) sufficient water recharge or fluid in place to maintain production over many years.[5]

Presently, large-scale power generation from geothermal energy is limited to vapor-dominated and hot water systems. In vapor-dominated systems, the dry high-temperature steam flows directly from the reservoir to, and is expanded in, a low-pressure turbine which drives a conventional electric generator. In hot water systems, where lower temperatures or higher pressures exist, the circulating fluid is water or brine, and heat is extracted by partially "flashing" the liquid to steam or transferring its heat to a secondary fluid.[6] Prototype binary-cycle technology is being developed to utilize reservoir temperatures below 350°F. The USSR is operating a binary fluid power plant utilizing Freon as the secondary fluid.[6] Other research is in progress on methods for utilizing geopressured and dry hot rock systems.

Geothermal energy is currently being developed as a power source in many favorable areas in the world. These areas are located where anomalous occurrences of low-pressure steam, hot water, or hot brines are present near the earth's surface. In the United States these types of resources are, so far as known, limited to the western and western Gulf states. The Geysers in northern California is the only geothermal facility in the United States producing electrical power commercially. It is the largest geothermal power plant in the world. This plant (11 units, 500 MW) is presently experiencing a growth rate of 110 MW per year, which may soon increase by virtue of contracts negotiated with additional steam producers in the area.

The U. S. Geological Survey has the responsibility to classify areas according to their potential value as a geothermal resource. A geothermal resource refers to heat in the earth's crust which is subject to recovery and use by man, whereas a geothermal reserve is heat that is economically recoverable and usable. Areas are classified as "known geothermal resource areas" (KGRAs) when "... the prospects for extraction of geothermal steam or associated geothermal resources are good enough to warrant expenditure of money for that purpose."[4]

According to the U. S. Geological Survey, the majority of the known KGRAs in the U. S. are located in 14 western states. Additionally, there are no KGRAs identified in the State of Oklahoma.[7] Therefore geothermal energy is not a viable alternative to the proposed station.

Petroleum Liquids

In view of the uncertain supply of imported oil (over one-third of U. S. consumption), and the importance of petroleum as motor-vehicle fuel and as petrochemical feedstock, it is in the public interest that new industrial uses be avoided.

Natural Gas

Although natural gas is highly desirable as a fuel from an environmental standpoint and is in current use by PSO, it is expected to become more scarce and possibly subject to allocation restrictions in the future. Accordingly, for reasons of practicality and public interest, new industrial consumption of this valuable fuel should be avoided.

Hydroelectric

There are only 791 MWe of undeveloped hydroelectric capacity in Oklahoma (ER, p. 9.2-7). Moreover, this capacity is not suitable for baseload operation because there is not enough water. Thus, hydroelectric power is not a viable option.



Advanced Nuclear Sources

Two advanced nuclear energy sources are the breeder reactor and the controlled thermonuclear reactor. Scientific feasibility of the latter has not yet been demonstrated. A demonstration breeder reactor plant is now in the design stage but more than a decade will be required to construct and operate the breeder to demonstrate commercial feasibility. Therefore, a breeder reactor is not a practical source for commercial power needed in the mid-1980s.

Municipal Solid Wastes

The burning of municipal wastes (mixed with coal) as a power-plant fuel has been demonstrated successfully and several utilities are now undertaking programs to exploit this fuel. The staff considers this fuel as a supplement to coal rather than a distinct alternative.

9.1.2.2 Competitive Sources - Economic Costs

After reviewing both the conventional and potential future energy sources, the staff concluded that only coal is a viable alternative source of energy for the proposed nuclear power generating station. Cost for power generating stations that use coal are compared with those for the proposed nuclear station in the following paragraphs. The comparisons are based on the proposed 2440 MWe two unit nuclear station; high-sulfur coal-fired station comprising three units, each with a rated capacity of 800 MWe, with a total generating capacity of 2400 MWe, and a low-sulfur generating station with the same capacity as the high-sulfur generating station.

The staff's economic cost estimates for the alternative coal and nuclear stations are presented in Table 9.1. The assumptions and methods used in making the comparison are discussed in the following paragraphs.

Capital Cost for Nuclear Generating Units

A study ("Economic Comparison of Baseload Generation Alternatives for New England Electric" by Arthur D. Little, Inc./S. S. Stoller Corp.) issued in March 1975, analyzed several reasonably current nuclear plant estimates by five architect-engineer firms, a reactor manufacturer and the AEC. These estimates were normalized to a 1974 dollar basis (two units, 1150 MWe each) and the average cost was determined. The average cost was escalated to commercial service dates of 1983 and 1985 using separate escalating factors for materials, equipment, and labor. The most probable capital cost estimate was 863 $/kW. The low variant was 777 $/kW and the high variant was 992 $/kW.

The CONCEPT Code at Oak Ridge National Laboratory is in the process of being updated. The new cost model for the BWR will not be available until sometime next year, but the new cost model for a PWR plant with mechanical draft cooling towers has recently been incorporated into the CONCEPT Code. The total cost for a PWR should be similar to a BWR. Using the new cost model for a PWR plant the capital cost for a 2440 MWe generating station was $2116 million or a unit cost of 867 $/kW. The old cost model for the BWR produced a cost of 675 $/kW. The staff considers the updated PWR model to be a better representation of BWR plant cost than the old BWR model. Thus a cost of 867 $/kW for the nuclear station was used in the cost comparison. The results of CONCEPT Code calculations are shown in Appendix H.

Capital Cost for Coal Generating Units

The Arthur D. Little study mentioned above regarding nuclear plant capital cost, also reviewed estimates for fossil plant capital cost. For three sets of architect engineer's estimates, there is good correlation in the ratio of fossil station costs to nuclear station cost in 1974 dollars. The coal station consisted of 3 units of 800 MWe each. For coal plants with $SO_2$ scrubbing equipment the capital cost (in 1974 dollars) is about 91% of the nuclear plant cost and for coal plants without $SO_2$ scrubbing equipment the capital cost (in 1974 dollars) is about 76% of the nuclear plant cost.

The station cost (1974 dollars) was broken down into direct cost (materials, equipment and labor) and these are escalated to 1983-1985 commercial operation dates. The range of capital cost estimates is shown in the following table for 3 units, 800 MWe each:

| Coal Station Three 800 MWe Units | Low Estimate | Most Probable | High Estimate |
|---|---|---|---|
| With $SO_2$ scrubber, $/kW | 641 | 697 | 802 |
| Without $SO_2$ scrubber, $/kW | 537 | 565 | 593 |

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Table 9.1. Capital Cost and Unit Generation Cost Comparison for Nuclear and Coal Fired Generation Station (Nominal 2500 MWe)[1]

| | NUCLEAR | | | HIGH-$SO_2$ COAL | | | LOW-$SO_2$ COAL | | |
|---|---|---|---|---|---|---|---|---|---|
| CAPITAL COST, $/kW, net | | 867 | | | 609 | | | 561 | |
| (capacity factor, %) | 70 | 60 | 50 | 70 | 60 | 50 | 70 | 60 | 50 |
| Unit Cost: mills/kWh | | | | | | | | | |
| Charges on Capital: | | | | | | | | | |
| cost of money and depreciation (12.69%) | 17.94 | 20.93 | 25.12 | 12.60 | 14.70 | 17.64 | 11.60 | 13.54 | 16.25 |
| Property tax and insurance | 6.54 | 7.60 | 9.12 | 4.58 | 5.34 | 6.41 | 4.22 | 4.92 | 5.90 |
| Operation & Maintenance | | | | | | | | | |
| fixed[2] | 2.43 | 2.84 | 3.41 | 4.22 | 4.93 | 5.91 | 3.34 | 3.91 | 4.69 |
| variable[2] | 0.10 | 0.10 | 0.10 | 3.79 | 3.79 | 3.79 | 0.16 | 0.16 | 0.16 |
| Fuel cost[2] | 10.77 | 10.77 | 10.77 | 17.87 | 17.87 | 17.87 | 23.02 | 23.02 | 23.02 |
| Carrying Charges on Fuel Working Capital | 0.89 | 0.97 | 1.09 | 0.23 | 0.23 | 0.23 | 0.30 | 0.30 | 0.30 |
| Decommissioning | 0.013 | 0.016 | 0.019 | --- | --- | --- | --- | --- | --- |
| Total mills/kWh[2] | 38.68 | 43.23 | 49.63 | 43.29 | 46.86 | 51.85 | 42.64 | 45.85 | 50.32 |
| Total mills/kWh[3] | 38.14 | 42.65 | 48.99 | 42.41 | 45.90 | 50.80 | 41.76 | 44.91 | 49.18 |
| Total mills/kWh[4] | 35.72 | 40.16 | 46.43 | 37.99 | 41.41 | 46.20 | 37.23 | 40.32 | 44.22 |
| Total mills/kWh[5] | 32.71 | 37.06 | 43.18 | 32.51 | 35.78 | 40.36 | 31.61 | 34.58 | 38.72 |

[1] 30-Year levelized cost.

[2] The 1985 costs were escalated at 5% per year and discounted at 9% per year over a 30 year lifetime to obtain a present worth value. The present value was amortized at 9% over 30 years.

[3] 5% escalation, 10% discount rate.

[4] 3% escalation, 9% discount rate.

[5] 1985 cost, escalation and discount rate not used.

The CONCEPT Code using approximately the same escalation factors (6%/year for equipment, 7.4%/year for labor, 4.3%/for materials) as Arthur D. Little (5.6%/year for equipment, 8.3%/year for labor, 4.2%/year for materials) generated a cost of 561 \$/kW without $SO_2$ scrubbers and 609 \$/kW for a station with $SO_2$ scrubbers for three 800 MWe units for 1983, 1984 and 1985 operation. The staff used the CONCEPT Code estimate for comparing nuclear and coal generating cost.

Fixed Charge Rate

Black Fox Station (BFS), Unit 1 and 2, is an integral part of planned generating facilities to supply capacity and energy to the systems of Public Service Company of Oklahoma (PSO), an Oklahoma corporation with corporate offices in Tulsa, Oklahoma; Associated Electric Cooperative, Inc. (Associated), a Missouri corporation with corporate offices in Springfield, Missouri; and Western Farmers Electric Cooperative (Western), an Oklahoma corporation with corporate offices in Anadarko, Oklahoma. PSO will own an undivided 60.87 percent interest, Associated will own an undivided 21.74 percent interest, and Western will own an undivided 17.39 percent interest in each unit.

The cost of money for PSO is 9.0% (3.75% or debt and 5.25% on equity), for Associated is 8.5%, and for Western is 8.0%. The corresponding sinking fund fraction for depreciation for each of the utilities is .73%, .81%, and .88%; income tax for PSO is 5.25%. The total for cost of money plus depreciation and income is 14.98% for PSO, 9.31% for Associated, and 8.88% for Western. The prorated cost of money plus depreciation and income tax based on the ownership fraction is 9.12%, 2.02%, and 1.54%, respectively, or a composite total of 12.69% for B~S Unit 1 and 2.

An allowance for property insurance of 0.25% and property tax of 2.50% for the BFS location was included as a separate cost. Property insurance and taxes were escalated at 5% per year and discounted at 10% per year to obtain the present value. The present value was then amortized over 30 years.

Interim replacement and nuclear liability are included in operation and maintenance cost. Decommissioning costs are shown separately for nuclear plants. A reasonable fixed charge rate for BFS Units 1 & 2 would be 15.44% (12.69% + 2.50% for taxes, + 0.25% for insurance). Although the applicant has chosen to use a fixed charge rate of 20% in the ER, the staff considers the 15.44% to be more realistic and will use it in unit generating cost calculations. Note in Table 9.1 that property insurance and taxes have been escalated and are shown separately.

The prorated cost of money for BFS Units 1 & 2 is 8.72%. A 9% interest rate was used as the discount factor to calculate carrying charges on fuel inventories. This is discussed further in later paragraphs.

Capacity Factors

A staff study "Statistical Analysis of Electric Plant Capacity Factors" by Robert G. Easterling on baseload steam-electric plant capacity factors presents results of a statistical analysis of coal and nuclear historical capacity factors of plants above 500 MWe. The document explains procedures for correctly specifying the statistical analysis to be performed and the results of such an analysis. The conclusion is that for coal plants the capacity factor is 56 ± 13% at a 95% prediction interval, and for nuclear plants, the capacity factor is 54 ± 14% for the same prediction interval. The width of these prediction intervals shows that a considerable shift would be required before there would be a statistical basis for predicting different capacity factors for coal and nuclear plants.

The fraction of fixed cost for a nuclear plant is about 1-1/2 to 2 times the fixed cost for a coal plant. Thus, a nuclear plant is more sensitive to capacity factor than a coal plant and there is a greater economic incentive to operate the nuclear plant at as high a capacity factor as possible than there is to operate a coal plant. Furthermore, the payout from efforts to improve the capacity factor of nuclear plants is about twice that for a coal plant.

The recognition of the importance of improving the capacity factor of nuclear and large fossil units is indicated by the number and types of programs being initiated by industry, private institutions and Federal agencies. A paper "New Directions Needed to Improve Power Plant Production" by Evan L. Kovacic - Program Director, FEA presents a sampling of the broadly based and expanding interest in this subject. The FEA goals are a 1985 target of an industry wide average of a 12% forced outage rate, an 80% availability factor and a 70% capacity factor for nuclear units and for coal-fired units 390 MW and larger.

The staff believes that the economic of baseload fossil and nuclear units should be compared using the same capacity factors. This analysis uses 50%, 60% and 70% capacity factors.

Escalation and Discount Rates

Forecasting electricity generating cost changes over a 40 year period (i.e., from 1976 to the end of the reactor life), obviously is subject to much uncertainty. There are likely to be significant fluctuations in these costs during the period. Nevertheless, the staff believes that over the long term, a reasonable assumption is that generating costs will not vary substantially from general inflation levels. An escalation rate of 5% per year is assumed for general inflation. Coal and nuclear fuel and operation and maintenance (O&M) costs are therefore escalated at 5% per year. Before escalating nuclear fuel costs certain upward adjustments are made to current costs. In the case of uranium, the base prive is adjusted upward from current production costs to reflect the continual depletion of higher grade ores and need to open new mining areas. Enrichment costs are adjusted upward from current charges to the charge likely to exist on a full cost recovery basis, i.e., $75 per SWU. These adjusted nuclear fuel costs are then escalated at 5% per year. Coal fuel costs are likewise escalated at 5% per year, although transportation costs, in particular, may well exceed this rate. Note is also made that no allowance is given to depletion of high yielding coal areas even though this may well occur over a 40 year period.

The discount rate used by the staff is the weighted cost of money to utilities including return on common stock, preferred stock and bond rates. For investor-owned utilities, this weighted cost is now approximately 12%. In the case of the Black Fox participants, about 39% is to be owned by utilities without equity financing, thus having a lower overall cost of money of 9% for the Black Fox participants. This is used as the discount rate for all the following cost analyses.

Operation and Maintenance

The operation and maintenance cost were obtained from the OMCST computer program* at ORNL. The OMCST code is designed to assist in examining average trends in costs, in determining sensitivity to technical and economic factors and in providing cost projections. The OMCST code provides the annual cost for operation and maintenance staff, the fixed and variable cost for maintenance materials, the fixed and variable cost for supplies and expenses, the cost for insurance and fees (including nuclear liability insurance) and the cost of administration and general expenses. The fixed and variable annual cost are totaled and converted to unit cost (mills/kWh) for the selected capacity factor. Costs are escalated to the year of initial operation, 1985 for Black Fox 1 & 2. The input for the O&M cost estimates are summarized in Table 9.2 and Table 9.3.

Table 9.2. Parameters for Calculating Operation and Maintenance Costs

| | |
|---|---|
| Escalation Rates to 1985, Percent/Year | |
| Wages | 7.0 |
| Fuel Oil Cost | 10.0 |
| Sludge Disposal Cost | 6.0 |
| Limestone Cost | 6.0 |
| Coml. Liab. Ins. Cost | 5.0 |
| Govt. Liab. Ins. Cost | 5.0 |
| Operating Fees | 3.0 |
| Material | 6.0 |
| Annual Average Salary Components | |
| Wage rate before adders (base year), $/hr. | 5.75 |
| Operator Fringe Benefits, Pct. | 30. |
| Plant Supervision & Technical, Pct. | 10. |
| $SO_2$ Removal Cost Components at Base Year 1975.0 | |
| Cost of Limestone, $/ton | 5.00 |
| Cost of Sludge Disposal, $/ton | 5.00 |

*A Procedure for Estimating Non-fuel Operation and Maintenance Costs for Large Steam-Electric Power Plants, ERDA 76-37.

Table 9.3. Fixed and Variable Portions of O&M Cost

| | Nuclear | | | High $SO_2$ Coal | | | Low $SO_2$ Coal | | |
|---|---|---|---|---|---|---|---|---|---|
| Capacity Factor, % | 70 | 60 | 50 | 70 | 60 | 50 | 70 | 60 | 50 |
| 1985 O&M Cost | | | | | | | | | |
| Fixed, M/kWh | 1.41 | 1.65 | 1.98 | 2.45 | 2.86 | 3.43 | 1.94 | 2.27 | 2.72 |
| Variable M/kWh | .06 | .06 | .06 | 2.20 | 2.20 | 2.20 | .09 | .09 | .09 |
| Levelized Costs | | | | | | | | | |
| Fixed, M/kWh | 2.43 | 2.84 | 3.41 | 4.22 | 4.93 | 5.91 | 3.34 | 3.91 | 4.69 |
| Variable M/kWh | .10 | .10 | .10 | 3.79 | 3.79 | 3.79 | .16 | .16 | .16 |

The 1985 O&M cost was escalated at 5% per year and discounted at 9% to obtain the 1985 present value. The present value was amortized over 30 years.

The 1985 cost and the levelized cost over 30 years are summarized in Table 9.3.

Fuel Cost - Nuclear

The nuclear fuel cycle cost calculations were based on the general procedures outlined in "Guide for Economic Evaluations of Nuclear Reactor Plant Designs" NUS-531. The reference fuel cycle cost components as developed in the "Final Generic Environmental Statement on the Use of Recycle Plutonium in Mixed Oxide Fuel in Light Water Cooled Reactors" (GESMO), NUREG-0002, were used. The reference values used are summarized in Table 9.4.

Table 9.4. Material and Service Unit Costs, 1975 Dollars

| Parameter | Reference |
|---|---|
| Mining and Milling, average \$/lb $U_3O_8$* | 28 |
| Conversion to $UF_6$, \$/kg U | 3.5 |
| Uranium Enrichment, \$/SWU | 75 |
| $UO_2$ Fabrication, \$/kg HM | 95 |
| MOX Fabrication, \$/kg HM** | 200 |
| Spent Fuel Transportation, \$/kg HM | 15 |
| Spent Fuel Storage, \$/kg HM-yr | 5 |
| Reprocessing, \$/kg HM*** | 150 |
| Waste Disposal, \$/kg HM+ | 50 |
| Plutonium Transportation, \$/g | 0.04 |
| Plutonium Storage, \$/g-yr | 2 |
| Spent Fuel Disposal, \$/kg++ | 100 |

*Use-weighted average cost (1975-2000), varies with consumption.

**Includes MOX shipping to reactor.

***Includes waste solidification.

+Includes waste shipment to Federal repository.

++Five years' spent fuel storage costs and shipping to repository are incurred in addition to disposal cost.

The fuel cycle calculations were based on equilibrium conditions. Two conditions were considered. One where the spent fuel is stored for 5 years and then shipped to a repository for disposal, the other was chemical reprocessing of the spent fuel to recover the plutonium (Pu) and remaining U-235 for recycle. The value for recovered plutonium and enriched U-235 was determined by making the cost of enriched fuel using Pu and/or recovered U-235 equal to the cost of a fuel using natural uranium. In other words the fuel cycle cost would be the same whether the recovered Pu and U-235 was recycled or sold at the calculated value for Pu and U-235. The assumptions used in the fuel cycle calculations are summarized in Table 9.5.

Table 9.5. Assumptions Used in the Fuel Cycle Calculations

| | | |
|---|---|---|
| . Reactor size and type | 1220 MWe | BWR |
| . Net thermal efficiency, % | | 32 |
| . Specific power MWT/MTHM | | 28* |
| . Irradiation level, MWDT/MTHM | | 27,500* |
| . Fresh fuel enrichment, % U-235 | | 2.73* |
| . Spent fuel enrichment, % U-235 | | 0.84* |
| . Fissile Pu recovered, kg/MTHM (after losses) | | 5.9* |
| . Tails assay, % U-235 | | 0.3** |
| . Pu replacement value, g of Pu/g U-235 | | 0.8** |
| . U-236 penalty - the quantity of recovered U-235 is reduced by multiplying by 0.904** | | |
| . Increased separative work, because of the presence of U-236 in recycled uranium, is 0.138 kg for each kilogram of recycled uranium.** | | |
| . Losses in conversion to $UF_6$ % | | .5 |
| . Losses in fabrication, % | | 1.5 |
| . Losses in chemical reprocessing, % | | 1.0 |

*WASH-1139(74), Nuclear Power Growth.
**GESMO

Cost for the various components of the fuel cycle were calculated in terms of dollars per kilogram of heavy metal ($/kg HM) and converted to mills/kWh based on an irradiation level of 27,500 MWD/MTHM. The costs were calculated in terms of 1975 dollars and the total fuel cycle cost then escalated at 5% per year to 1985. The 1985 present value for the 30 year life of the plant was calculated by escalating the 1985 cost at 5% per year and discounting at 9% per year. The present value for the 30 year period was then amortized over 30 years.

It should be noted that the 28 $/lb for $U_3O_8$ is a use-weighted average cost (1975-2000) and takes account of the increasing cost of $U_3O_8$ due to depletion of high grade ores.

The fuel cycle cost excluding carrying charges is summarized in Table 9.6 for the no recycle case and for the recycle of plutonium and spent uranium case.

Carrying charges on the funds required to support the fuel cycle were calculated based on the following set of assumptions:

- 1 year from $U_3O_8$ purchase through conversion to $UF_6$, enrichment and fabrication.
- Resident time in the reactor based on capacity factors 50%, 60%, 70% and 27,500 MWD/MTHM exposure.
- For the throw away fuel (no recycle case) a 5 year storage is included before final disposal.

Table 9.6. Summary of Nuclear Fuel Cycle Cost

| | No Recycle | | Recycle Pu & U | |
|---|---|---|---|---|
| | $/kgHM | Mills/kWh | $/kgHM | Mills/kWh |
| $U_3O_8$ + Enrichment | 684 | 3.24 | 684 | 3.24 |
| Fabrication | 95 | .45 | 119* | .56 |
| Spent Fuel Disposal: | | | | |
| Storage, 5 yr/1 yr | 25 | .12 | 5 | .02 |
| Shipping | 15 | .07 | 15 | .07 |
| Disposal | 100 | .47 | | |
| Reprocessing | | | 150 | .71 |
| Waste disposal | | | 50 | .24 |
| Spent U-235 Credit | | | (85) | (.40) |
| Pu Credit | | | (140) | (.66) |
| Pu Storage, 1 yr | | | 12 | .06 |
| Sub total (1975 $) | 919 | 4.35 | 810 | 3.84 |
| Escalated to 1985 at 5% | 1497 | 7.09 | 1319 | 6.25 |
| Present value 1985, 5% escalation and 9% discount/yr, $/kgHM | 26,496 | 125.49 | 23,345 | 110.62 |
| Present value amortized over 30 years at 9% | 2,579 | 12.21 | 2,272 | 10.77 |

*77% of fuel is $UO_2$ at 95 $/kgHM fabrication cost and 23% of fuel is $PuO_2$ + $UO_2$ at 200 $/kgHM fabrication cost.

- For the recycle case a one year storage of spent fuel is included before reprocessing.
- The credit for Pu and spent uranium is taken on the next succeeding fuel cycle.
- A 9% interest charge on invested funds required to support the fuel cycle.

The carrying charges for the two fuel cycle cases are summarized in Table 9.7.

Table 9.7. Carrying Charges for Nuclear Fuel

| | No Recycle | | | Recycle Pu & U | | |
|---|---|---|---|---|---|---|
| Capacity Factor % | 50 | 60 | 70 | 50 | 60 | 70 |
| Carrying charges for fuel (9%) | | | | | | |
| 1975 dollars, $/kgHM | 111 | 94 | 83 | 82 | 73 | 67 |
| Escalated to 1985 | 181 | 154 | 136 | 134 | 119 | 109 |
| Present value (1985) 30 years, at 5% escalation and 9% discount/yr, $/kgHM | 3204 | 2726 | 2407 | 2372 | 2106 | 1929 |
| Present value amortized over 30 years, at 9% | 312 | 265 | 234 | 231 | 205 | 188 |
| Unit Cost, mills/kWh | 1.48 | 1.25 | 1.11 | 1.09 | .97 | 89 |

Fuel Cost - Coal

Oklahoma has significant coal reserves in the eastern part of the state. These reserves amount to slightly more than 3 billion tons, with a 50 to 70 percent recovery rate. The applicant states in the ER (ER page 9.2-4) that less than 4 percent is strippable coal, with the remainder being recoverable only by deep mining techniques.

The report further states that much of the Oklahoma coal reserve is suitable for metallurgical use at premium prices; however, some coal is available for possible electric power generation. The applicant's investigation into Oklahoma coal possibilities for PSO use revealed the following three areas which could produce coal for boiler fuel.

Rogers County. The Rogers County coal producing area contains approximately 25 million tons of recoverable reserves, but already has 10 million tons dedicated to Missouri Public Service Company use. This coal is presently being strip mined by Peabody Coal Company and is spread over more than 2500 square miles thereby resulting in high transportation costs which would offset strip mining cost savings.

LeFlore and Haskell Counties. The Poteau area contains approximately 41 million tons of recoverable coal. Coal is available from this area with Peabody controlling 34 percent of the reserves. This coal has 0.61% sulfur content. Mining costs would be high due to the terrain and depth of the coal deposits.

The Spiro area consisting of 5240 acres containing approximately 20 million tons of recoverable coal is leased from the Federal Government by Garland Coal Company. Leases held by Kerr-McGee in nearby areas are estimated to include 50 million tons of recoverable coal. Kerr-McGee also has coal reserves in Haskell County with more than 100 million tons of recoverable coal; this coal requires deep mining processes. Kerr-McGee opened a deep mine near Stigler, Haskell County in 1969, which was the only underground mine in the state; it was closed due to overburden support problems.

The prospect for deep mining in LeFlore and Haskell counties is not promising at the present time. The mining companies have not developed the techniques required to support the shale overburden found in this area.

Okmulgee County. In 1971 Stone and Webster recommended studies for consideration of possible siting of a power generating station near Henryetta. This area, known as Ben Hur, is mainly controlled by Peabody Coal Company. PSO and Peabody Coal Company entered into a joint drilling program in 1972 to determine the coal reserve in the Ben Hur area. Coal reserves determined from the drilling program amount to approximately 5000 tons per acre with a recovery of 50 percent by deep mining methods. For the 21,438 acres involved, about 55 million tons are estimated to be recoverable. Overburden ranges from 300 feet to 625 feet with roof conditions in the mine area being fairly good but requiring roof bolt anchorage. The run-of-the-mine coal would average about 11,650 Btu/lb with approximately 2.3% sulfur content. Peabody controls 23% of the recoverable coal in this area.

A 450 MW coal fired unit operated at 70% capacity factor would require approximately one million tons of Ben Hur coal per year. Sufficient coal is available from this area to support 900 MW of coal fired electric power generation for about 27 years. Estimated costs of producing the coal plus costs associated with sulfur removal, water supply, land costs, and the limited fuel supply are not favorable to building a power generating station in the area at this time.

Coal in Oklahoma is a valuable, economic resource, but its use does not appear to be advantageous for electric power generation by PSO at this time.

Coal Summary. Major additions in the PSO system and the systems of other utilities in the Southwest Power Pool, will utilize coal prior to 1983. The new coal fueled generating units to be added in the PSO system prior to 1983 will utilize western coal because of its low sulfur content and its relative cost and availability in relation to other alternate coal supplies. The alternate use of Oklahoma coal would result in major problems associated with high sulfur content, deep mining of thin coal seams, and the land reclamation of surface mined coal.

The advisability of long term reliance upon western coal for baseload energy production is dependent upon logistics of transportation and labor as well as the future problems of strip mining operations. The ER (ER page 9.2-13) contains applicant's estimates of coal cost by the three utilities (PSO, Associated and Western). Their estimates of coal cost are summarized below. Associated estimated cost of coal (ER page 9.2-13) with a heat content of 8000 Btu/lb to be $11.30/ton in 1974 delivered to the site and that coal costs were escalated at 10% per year. Western estimated cost of coal (ER page 9.3-15a) with a heat content of 9,500 Btu/lb to be $20/ton in 1986 delivered to the site.

In the applicant's table (ER page 8.2-11, Table 8.2-2) comparing alternatives the applicant used a 30 year levelized cost of 29.73 mills/kWh for low sulfur coal for 1985 operation and 23.38 mills/kWh for high sulfur coal.

The following is a summary of staff's independent estimate of coal cost. The 1975 cost for coal delivered to steam-electric plants is found in a staff report by the Bureau of Power, FPC entitled "Annual Summary of Cost and Quality of Steam-Electric Plant Fuels, 1975." The report does not show Oklahoma using coal for electricity generation. Almost all electricity is produced with natural gas. However, data on coal cost delivered to states in the central U.S. is reported. The average cost of Wyoming low sulfur coal delivered to steam-electric plants in Kansas, Illinois, Missouri, Indiana and Nebraska for 1975 was $15.67/ton. The average heating value of this coal was 9876 Btu/lb. For Montana low sulfur coal delivered to Kentucky, Iowa, Indiana and Illinois, the average cost was $17.77/ton and the heating value was 9364 Btu/lb. Approximately 93% of this coal was contract price.

The average 1975 price for Montana and Wyoming coal delivered to the above states was $16.70/ton.

The average contract price in 1975 for strip mined coal in Oklahoma delivered to a generating unit in Missouri was $12.15/ton. The heating value of this coal was 11,981 Btu/lb and the sulfur content was 3.7%. However the strip mineable coal resources in Oklahoma are limited and there is no estimate of the cost of deep mining coal in Oklahoma. The uncommitted 15 million tons of strip mineable resources in Rogers County would provide approximately 3 years supply for a 2,500 MWe station.

The average price for high sulfur (3% sulfur), Illinois coal delivered to Illinois, Indiana, Wisconsin, Iowa, Minnesota and Missouri in 1975 was $14.29/ton. The average heating value of this coal was 10,660 Btu/lb. The staff in its estimate used a price of $16.70/ton (heating value 9,364 Btu/lb) for low sulfur coal delivered and a price of $14.29/ton for high sulfur coal (heating value 10,660 Btu/lb) delivered in 1975. These prices were escalated to 1985 at 5% per year. The 1985 price for coal was escalated at 5% per year and discounted at 9% over the 30 year life of the plant. The 1985 present value was amortized at 9% interest over the 30 year plant life. These costs are summarized in Table 9.8.

Table 9.8. Calculation of Levelized Costs of Coal

| | High Sulfur | Low Sulfur |
|---|---|---|
| . 1975 coal cost, $/ton | 14.29 | 16.70 |
| . Escalated at 5%/yr to 1985, $/ton | 23.28 | 27.20 |
| . 1985 price escalated at 5% per yr, discounted at 9% and amortized over 30 years, at 9%, $/ton | 40.11 | 46.86 |
| . Unit cost, mills/kWh | 17.87* | 23.02** |

*Using a net heat rate of 9,500 Btu/kWh and a coal heating value of 10,660 Btu/lb.

**Using a net heat rate of 9,200 Btu/kWh and a coal heating value of 9,364 Btu/lb.

The staff assumed that a 3 months supply of coal would be stockpiled at the generating station. Also it is assumed that if it is necessary to use this coal at any time the stockpile would be credited at the then current price for coal and the amount used would be replaced at the same price. The carrying charge for the coal stockpile is based on 9% interest, 1985 price for coal and a three months coal supply. The cost of the coal stockpile and carrying charges are summarized in Table 9.9.

Table 9.9. Cost and Carrying Charges for Coal Stockpile

| | | | |
|---|---|---|---|
| . Capacity Factor, % | 50 | 60 | 70 |
| . Cost of 3 months stockpile: | | | |
| - High sulfur coal, $\$10^6$ | 28.40 | 34.08 | 39.76 |
| - Low sulfur coal, $\$10^6$ | 36.60 | 43.92 | 51.24 |
| . Unit cost of carrying charges: | | | |
| - High sulfur coal, mills/kWh | .23 | .23 | .23 |
| - Low sulfur coal, mills/kWh | .30 | .30 | .30 |

The annual coal requirements and the 30 year requirements are summarized in Table 9.10. The quantities are averages of high sulfur and low sulfur coal. Note that the 15 million tons of uncommitted strip mineable coal in Rogers County, Oklahoma would be sufficient for about 2-3 years of operation.

Table 9.10. Coal Requirements for a 2500 MWe Station

| Capacity Factor, % | 50 | 60 | 70 |
|---|---|---|---|
| Tons/yr x $10^6$ | 5.1 | 6.1 | 7.1 |
| 30 yr requirements, tons x $10^6$ | 154 | 185 | 215 |

Decommissioning Cost

As discussed in Section 10.2.4, estimated decommissioning costs range from $1 million plus an annual maintenance expense of $100,000 per year for the lowest level of decommissioning to a cost of 83.4 million for complete restoration of the site.

The staff considered the upper and lower range of decommissioning costs. For the lowest it was assumed that the 1975 cost would be $1 million plus a fund that would produce $100,000 per year revenue at a 10% rate of interest ($1 million fund). A total of $2 million would be required in 1975. This was escalated at 5% per year to 2015 (40 years) to yield a decommissioning cost of $14.08 million at the end of plant life. The sinking fund required to produce the $14.08 million at the end of plant life at 9% interest is $103,000/year.

For the high case where the site is restored to its original condition the staff used 83.4 million as present cost of decommissioning and a 5% long term escalation rate over 40 years (10 years to commercial operation plus 30 year plant life), the decommissioning cost would be $587 million at the end of plant life in year 2015. The annual sinking fund payment required over 30 years at a 9% interest rate to produce this amount is $4.31 million per year. The above costs are for one unit.

Table 9.11 summarizes the annual cost and unit cost as a function of capacity factor. The costs in Table 9.11 have been adjusted for a two unit station.

Summary

The cost for Black Fox Station, Units 1 and 2 and for coal alternatives are summarized in Table 9.1 for an annual escalation rate of 5% and a discount rate of 9%. Also shown at the bottom of the table are the total costs for 5% escalation and 10% discount, 3% escalation and 9% discount, and 1985 cost for zero escalation and discount rates. Figure 9.1 is a graph of total generation cost as a function of capacity factors for two sets of conditions, 5% escalation and 9% discount condition and 3% escalation and 9% discount rate condition.

719 177

719 019

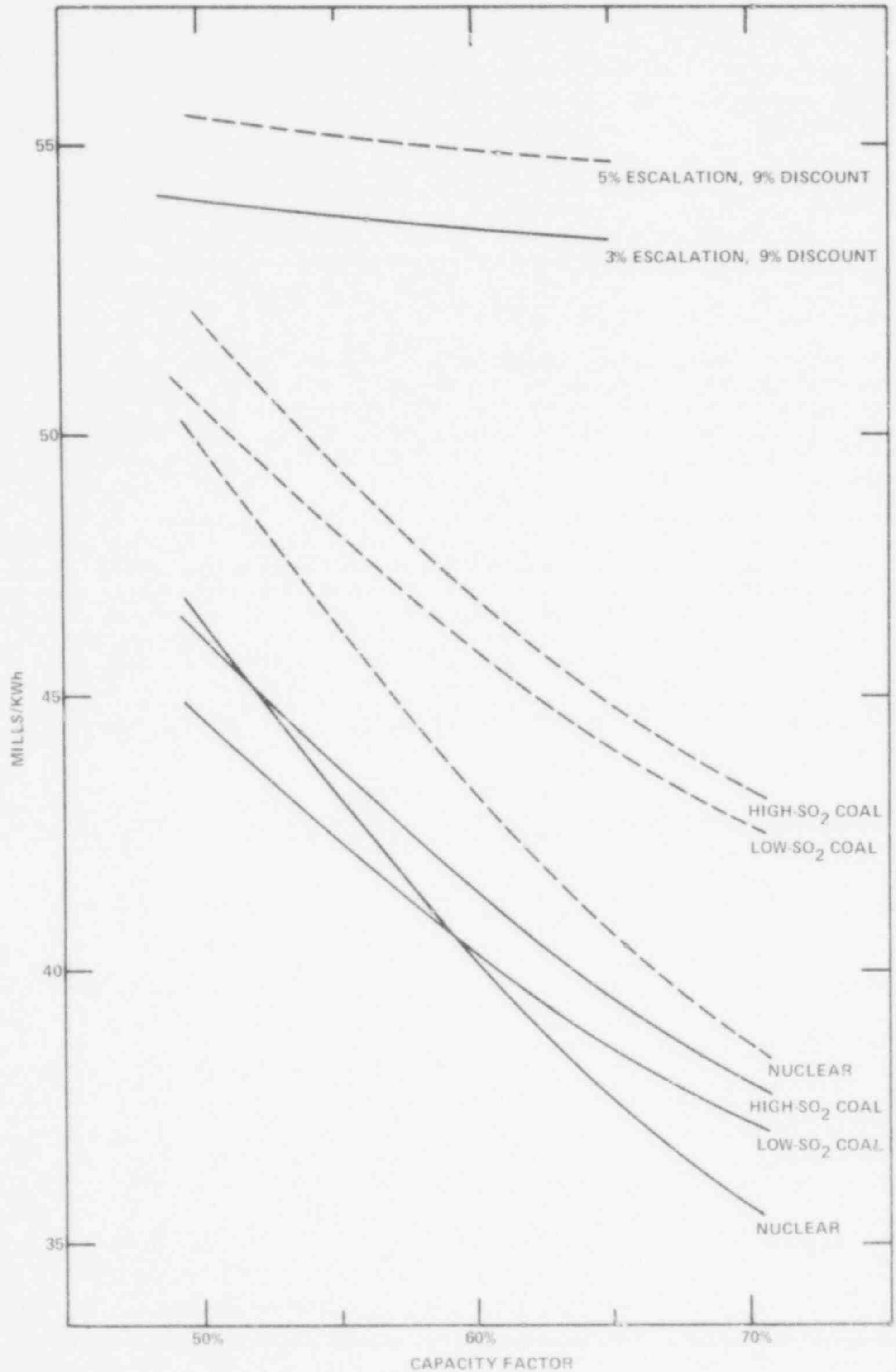


Figure 9.1 Total Generating Cost vs. Capacity Factor for Large (2400 MWE) Baseload Units from Table 9.1.

Table 9.11. Calculation of Cost of Decommissioning for Black Fox Station

| | Lowest Cost | | | Highest Cost | | |
|---|---|---|---|---|---|---|
| Annual sinking fund payment, $\$10^6$ | | .206 | | | 8.62 | |
| Capacity Factor, % | 50 | 60 | 70 | 50 | 60 | 70 |
| Unit cost, mills/kWh | .019 | .016 | .013 | .79 | .66 | .56 |

9.1.2.3 Competitive Sources - Environmental Costs

In addition to the environmental costs, the differing health effects from using coal and nuclear fuels should be considered in the environmental balance. In making this balance the entire fuel cycle rather than just the power-generation phase should be considered. For coal, the cycle consists of mining, fuel transportation, processing, and power generation. The nuclear fuel cycle includes mining, milling, fuel preparation, fuel transportation, power generation, and waste disposal.

Comar and Sagan[33] recently reviewed the literature (41 references) concerning premature deaths associated with the operation of 1000-MWe coal and nuclear power plants. The data summarized in Table 9.12 give the highest and lowest estimates of premature deaths for the general public and for occupational employees. Premature deaths include accidental ("prompt") deaths and delayed deaths, e.g., from the long-term effects of exposure to low-level radiation or the products of the combustion of coal. Genetic effects are not included in Table 9.12 but the authors state that for the nuclear fuel cycle, "... there are enough data to indicate the values given (0.01-0.16 deaths per year in Table 9.12) for nonaccidental premature deaths would not be increased by more than 50% in the first generation or by more than several fold after hundreds of years." Large nuclear accidents of low probability did not significantly affect the values (see later discussion).

Table 9.12. Premature Deaths per Year Associated with Operation of a 1000-MWe Power Plant

| | Coal | Nuclear |
|---|---|---|
| General public | | |
| Transport | 0.55-1.3 | a |
| Processing | 1-10 | a |
| Power plant operation | 0.067-100 | 0.01-0.16[b] |
| Total | 1.6-111 | 0.01-0.6 |
| Occupational | | |
| Entire fuel cycle | 0.54-5.0 | 0.10-0.86 |
| Total - occupational and and public | 2-116 | 0.11-1.0 |

[a]Indicates no data found; effects, if any, are presumably too low to be observed, and no theoretical basis for prediction.

[b]Includes processing.

712 179

719 021

The premature public (non-occupational) deaths per year caused by the transportation of coal (0.55-1.3) are primarily railroad deaths occurring at grade crossings.[34] The effects of air pollutants emitted from the combustion of coal in a coal-fired power plant are a matter of considerable uncertainty, as the premature death-estimate range of 0.067 to 100 would suggest. The public death estimated for coal processing (110) are attributed to air pollution originating from the oxidation of culm banks (refuse coal screenings).[35] The estimate of premature public deaths resulting from the nuclear fuel cycle (0.01 to 0.16 per year) represents less than one-tenth of the public deaths from the coal cycle (1.6 to 111 per year).

Estimates of premature occupational deaths range from 0.54 to 5.0 per year for the coal fuel cycle and from 0.1 to 0.86 per year for the nuclear fuel cycle. For coal, the largest contributors are mining and transport; for the nuclear cycle, the largest contributors are processing and mining.

In Table 9.13 Comar and Sagan's estimates of premature deaths are presented in terms of the degree of enhanced risk to which individuals and populations are exposed. Comar and Sagan also presented (see Table 9.13) (1) values illustrative of the absolute number of premature deaths predicted for the routine operation of 300 plants for their typical lifetime of 30 years, and (2) an estimate, based on the draft WASH-1400 report,[36] that ten statistical deaths would result from catastrophic nuclear accidents in 30 years from 300 plants. The final WASH-1400 report[37] was available subsequent to the Comar and Sagan article; however, Comar and Sagan note that while the numerical values in the final version of WASH-1400 differ from those used by them, they would not materially affect the comparisons made.

Table 9.13. Summary of Implications of Qualitative Assessments of Health Effects in General Population Associated with Electricity Production (all values rounded)

| | | Coal | Nuclear |
|---|---|---|---|
| Premature deaths/year/1000 MWe plant | | 2-100 | 0.01-0.2 |
| Added risk per year | | 1 in 10,000 | 1 in 5,000,000 |
| | Normal Risk of Death per Year | Enhanced Risk of Death per Year Because of Electricity Production[a] | |
| All ages | 1 in 100 | 1.01 in 100 | 1.00002 in 100 |
| Number of premature deaths in 30 years associated with routine operations of 300 plants[b] | | 20,000 to 1,000,000 | 100 to 2,000 |
| Number of deaths statistically predicted from catastrophic accidents in 30 years from 300 plants[c] | | | 10 |

[a]Upper estimates.

[b]This represents the total operation for a generation of power plants that would supply about 300 million people.

[c]From: "An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," USAEC, WASH-1400 (draft), 1974. (Based on 1 chance in $10^6$ of an accident per reactor-year causing 1000 immediate and delayed casualties.)

An important source of information in the field of industrial health effects is a study[34] by the Council on Environmental Quality. The estimates given in the study were generally within the ranges given in Table 9.12.

In a recent article by Rose et al.,[38] the estimates of health effects of power generation were generally within the ranges cited in Table 9.12; predicted deaths per 1000-MWe plant-year were 20 to 100 for coal and 0.502 for nuclear. The estimate was higher for total incapacitation and premature death owing to black-lung disease in coal miners (10 deaths per year). Recent improvements in mining practices are expected to lower this toll. This paper also discussed deaths of the public from large nuclear accidents. Utilizing the value of 0.0004 "prompt" deaths per reactor-year from the draft WASH-1400 report,[36] Rose et al. estimated delayed deaths--from cancers and genetic faults--could increase the total by a factor of ten, to 0.004 deaths. Applying the factor of 25 suggested by the American Physical Society's critique[39] of the draft WASH-1400 report, Rose et al. arrived at an expectation value of 0.01 deaths per reactor-year. This value is a small fraction of their estimate for the complete nuclear fuel cycle of 0.168 radiation-related deaths and 0.334 accidental deaths not radiation-related.

It was also mentioned by Rose et al. that improvements in methods for scrubbing $SO_2$ out of the gaseous effluents from coal combustion may reduce the highest figure in Table 9.12--the 100 deaths possibly resulting from the sulfurous effluents. Such a reduction would still leave higher health costs from the coal cycle, but nearer the effects from the nuclear cycle. It was also noted that new regulations for radioactive effluents from LWRs (10 CFR Part 50, Appendix I) will reduce the radioactivity in off-gas releases by a factor of 100. Such improvements will reduce the estimates of radiation-related deaths associated with reactor operation.

The data in Table 9.13 place in perspective the enhancement of risk from both fuel cycles. For the nuclear cycle, the risk of death increases from an original value of 1 per 100 individuals per year to 1.00002 per 100 individuals per year; for the coal cycle, the increase is from 1 to 1.01 per 100 individuals. Providing further perspective regarding the small statistical risk of large nuclear accidents, the Reactor Safety Study[37] finds that "All non-nuclear accidents examined in this study, including fires, explosions, toxic chemical releases, dam failures, airplane crashes, earthquakes, hurricanes and tornadoes, are much more likely to occur and can have consequences comparable to, or larger than, those of nuclear accidents."

Although it might be expected that public acceptance would be governed by risk evaluations of this kind, Comar and Sagan[33] point out that other factors may be involved: "It is a matter of conjecture whether the public would accept the probability, although very small, of a single nuclear event causing an immediate loss of hundreds of lives as preferable to or in place of the loss of a large number of lives from fossil fuel combustion occurring in driblets and therefore unnoticed." This view has been expressed by others.[37,40]

After consideration of the comparative health analyses and results discussed above, which include the risks from improbable nuclear accidents, the staff concludes that the total societal risk of premature deaths from electrical power generation using nuclear fuel is lower than the risk from power generation using coal.

#### 9.1.2.4 Conclusion

The summary of staff's estimated environmental costs for alternative plants are given in Table 9.14. It was previously concluded that the alternatives of no new generating capacity and of using other fuels and energy sources were not feasible choices to provide the required amount of power at the time it would be needed; consequently, the remaining choice was between nuclear and coal fuels. On the basis of the information summarized in Tables 9.1 and 9.14, the staff concludes that the overall economic and environmental costs of the nuclear alternative are less than or no greater than those for the coal-fired alternative. Construction of the proposed nuclear plant is therefore a reasonable choice.

## 9.2 SITES

### 9.2.1 Regional Considerations

The applicant's major load center, comprising half of the company's load, is metropolitan Tulsa. Th fore, for pow load and transmission considerations, PSO limited its geographic screening ssible plant sites to northeast Oklahoma (ER, Sec. 9.2.1.4). Since PSO also serves south- rn, central, and southeastern Oklahoma and also exports a substantial amount of power (see . 8), the staff has examined siting possibilities throughout the State with respect to population density, seismicity, and water availability.

The population density of Oklahoma is so low that outside of a ring 20 to 30 miles from the metropolitan areas of Oklahoma City or Tulsa, judicious placement of a plant should site it well within NRC's guidelines on population density.[8]

Seismic risk is low throughout Oklahoma.[9] The highest seismic risk within the State, Zone 2, is in a swath starting at Oklahoma City with a width about twice the size of the Oklahoma City metropolitan area and extending north into Kansas.[9] Therefore, it would be most cost effective to avoid north-central Oklahoma for optimal siting within Oklahoma, even though nuclear plants are sited in other states in moderate damage, Zone 2, seismic-risk areas like north-central Oklahoma.

Table 9.14. Comparative Environmental Costs for 2440-MWe Coal Plant and the BFS Nuclear Plant at Full Output

| Impact | Coal | Nuclear |
|---|---|---|
| Land Use, acres | | |
| Station proper and associated ponds | ∿ 175 | ∿ 190 |
| Fuel storage | ∿ 25 | < 1 |
| Waste storage | ∿ 500 (offsite) | < 1 |
| Exclusion area | Not required | ∿ 560 |
| Release to Air[a] | | |
| Dust, tons/day | 25 | None |
| Sulfur dioxide, tons/day | 330 | None |
| Nitrogen oxides, tons/day | 194 | None |
| Radioactivity, Ci/yr | Small | 14,600 |
| Releases to Surface Water | | |
| Chemicals dissolved in blowdown, tons/day | ∿ 12 | b/ |
| Radioactivity, Ci/yr | None | ∿ 500 |
| Water consumed, millions gal/day | ∿ 27 | 40 |
| Fuel | | |
| Consumed | ∿ 30,000 tons/day | ∿ 17.8 lb/day[c] |
| Ash | ∿ 3,000 tons/day | ∿ 17.8 lb/day[d] |
| Social | Moderate | Moderate |
| Esthetic | Both require large industrial-type structures and cooling towers. Coal yard, ash pit, tall stack required. | |
| Health Effects | See Tables 9.12 and 9.13 for values normalized for 1000 MWe power plant | |
| Premature death | | |

[a]Coal-fired plant emissions estimated on the basis that the plant just meets applicable EPA standards.

[b]Information not available.

[c]About 9.0 lb/day each of U-235, U-238.

[d]Fission and transmutation products.

A multidisciplinary working group convened by the National Academy of Engineering has suggested that not more than 20% of the low flow of a river should be consumed* by a single installation using once-through cooling.[10] Closed-cycle cooling systems kill more organisms than once-through systems because of temperature changes, chemical toxins, and physical trauma as the water is recycled. Closed-cycle systems also consume more water because more is evaporated, and they degrade the river's chemistry more because of chemical additions and concentration of salts

*Water consumed, or consumptively used, generally is that lost to the atmosphere through evaporation and drift.

present in river water. Therefore, consumptive water use by a closed-cycle system should probably be limited to less than 20% of the low flow.

Oklahoma has no state power plant siting law or recommendations, but a number of states have adopted such recommendations. Indiana's is typical. Indiana's criterion for acceptable water usage is that a typical 2000-MWe fossil-fuel plant with cooling towers should have a consumptive water use of no more than about 44 cfs (1.25 $m^3$/sec) and, together with plants upstream, should not consume more than 20% of the 7-day, 10-year low flow,[11] which on this basis would be 220 cfs (6.25 $m^3$/sec) if there were no other plants upstream. The staff believes that this criterion is reasonable. Because a typical nuclear plant is about 6% less efficient than a typical fossil-fuel plant and all its waste heat is dissipated in cooling water (in a fossil plant one-fifth of the waste heat is dissipated through the stack), a nuclear plant consumes about 1.6 times as much water, or requires a 7-day, 10-year low flow of 352 cfs (10.0 $m^3$/sec). A similar quantity, 325 cfs (9.2 $m^3$/sec), can be calculated on the basis of the Black Fox Station's projected maximum makeup demand, 65 cfs (1.84 $m^3$/sec) (ER, Table 3.4-5).

Only the Arkansas River, starting near Tulsa with a 7-day, 10-year low flow of 310 cfs (500 cfs by the time it gets to Muskogee) and the Red River, starting near Hugo with a 7-day, 10-year low flow of 310 cfs, begin to satisfy the recommendations of the National Academy of Engineering or typical State water supply recommendations for siting.[12] These areas are in eastern or extreme southeastern Oklahoma.

Since Oologah Reservoir is the water source for an alternative site, other reservoirs with minimum historical water volumes equal to or greater than Oologah's should also be satisfactory for siting. There are a number of these, mainly in the eastern and southern portion of the State, at which a plant could be sited.[13]

While northeastern Oklahoma is better endowed with water than other areas, there is sufficient water in the southeast and south to site a plant on a river or reservoir. Siting in the western portion of the State would be difficult because of limited water supplies.

Regionally, population is no barrier to a site selection. North-central Oklahoma preferably should be avoided because of higher cost of construction because of seismic risk, and western Oklahoma would be a difficult region in which to find suitable sites because of water availability. This leaves the eastern portion of the State, north to south, in which siting is regionally optimal.

### 9.2.2 Candidate Site Alternatives

After excluding the southeastern portion of Oklahoma because of electrical load consideration at Tulsa, PSO examined the northeastern portion of the State. Meteorology, demography, ecology, special land usage and designation, transportation, earth sciences, water resources, availability and quality were factors considered to identify smaller areas within northeastern Oklahoma that would best qualify as power station siting areas. The study attempted to exclude areas with rare and endangered species, pristine areas, areas with unusual habitats, and areas with fragile environments.

The applicant's initial analysis yielded 50 possible site areas. These were subjected to a series of detailed analyses and screening (ER, Fig. 9.2-21) that eliminated all but 13 from further consideration. A representative site was selected for each of the 13 potential site areas, and six of these 13 sites were subjected to additional investigation. A site was excluded, for example, if undesirable building foundation characteristics were present. The four eventually considered the most desirable are the alternative sites discussed below. A cost and environmental comparison showed that cooling towers should be utilized on all four sites. The locations of these sites are shown in Figure 9.2.

The South Inola Site on the east bank of the Verdigris River (Rogers County, 23 miles east of central Tulsa) was selected by the applicant as the proposed site for the Black Fox Station. It is described in detail in Section 2. The site consists primarily of pastures and woodland. Water supply would be by pipeline from the Verdigris River.

The North Inola Site is six miles northwest of South Inola. It is similar in most respects to South Inola, but is slightly further from the Verdigris.

The Wagoner Site, in Wagoner County, is also similar to South Inola, particularly in terms of land use. It has a slightly lower elevation than South Inola and adjacent land is subject to periodic flooding. Like North and South Inola, Wagoner lies adjacent to the Verdigris River.

The Oologah Site in Rogers County is just southeast of Oologah Reservoir, from which makeup water would be drawn. While land use at this site is generally similar to the other sites, Oologah

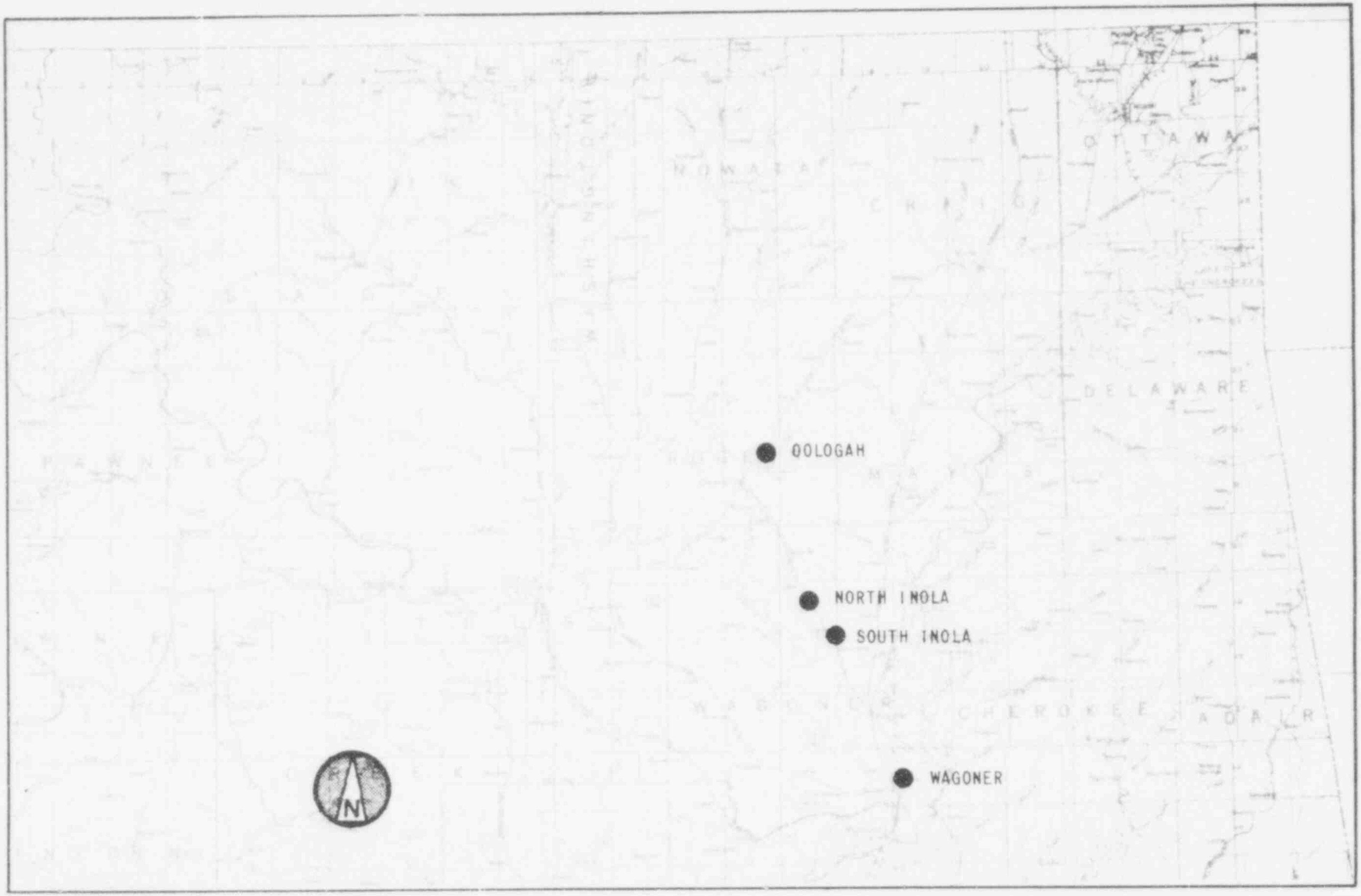


Fig. 9.2. Four Candidate Sites. From ER, Fig. 9.3-1.

differs in that it is further from water, has a rougher terrain, and its southern and eastern portions are old strip-mine spoils.

All the sites would utilize mechanical-draft cooling towers, and water, whether drawn directly from the Oologah Reservoir or the Verdigris River, would ultimately be supplied, especially during low flow, from Oologah Reservoir storage.

The staff has examined each of the four sites from the air and on the ground, and finds them all to be viable alternatives.

### 9.2.3 Comparison of Candidate Site Alternatives

A summary description of the site characteristics is given in the ER, Table 9.3-1. The staff believes that sites other than South Inola would require further investigation to determine building foundation acceptability and that three sites are potential habitat for three endangered species, while Oologah is potential habitat for one endangered species. Otherwise the staff concurs with the table. The applicant assigned an importance value to each of the characteristics and multiplied by a favorability factor to determine a ranking of the site desirability for each characteristic. Adding these values gives a comparison of the relative desirability of each site (ER, Table 9.3-2). Given that any such ranking system is somewhat subjective, the relative impact rankings of 282 for Oologah, 290 for South Inola, 308 for Wagoner, and 290 for North Inola (ER, Table 9.3-2) really show that the four sites are about equally suitable. Only two large comparative disadvantages emerged, namely that transportation, particularly by barge, would be difficult at Oologah, and that North Inola is nearer to industry than the other sites.

Based on terrestrial ecology criteria, the staff finds that the impacts of the Black Fox Station would be no less if it were located at any of the alternative sites than at the proposed South Inola site. The Wagoner Site is the least acceptable because of the presence of a large wetland habitat (riverine woods, see Sec. 2) on and near the site. The other two sites are nearly equal. The South Inola Site does have a unique habitat (see Sec. 5.6.1.2) on the northwestern corner, but the proposed construction plan will not affect this area, and the site has a good potential for natural recovery of native habitat during the life of the plant. On the other hand, the Oologah Site is so disturbed by strip mining and grazing that there would be no appreciable ecological loss if the plant were to be built there, but this same degree of disturbance puts potentially severe constraints on natural recovery of native habitats.

Because site characteristics do not indicate one site to be clearly preferable to the others, PSO has chosen the South Inola Site for the Black Fox Station through a cost comparison among the four sites. The comparison is shown in Table 9.15. South Inola has the lowest capital and lowest operating costs of the four alternatives. While the staff finds it reasonable that Oologah will cost more than South Inola, it does not find the cost analysis to be of sufficient depth to make the difference of eight ranking points between South Inola and North Inola a convincing basis upon which a siting decision can be determined. The staff believes that the Oologah Site should be excluded for reasons of cost, but that South Inola, Wagoner, and North Inola are cost competitive and a. have adequate site characteristics.

Since no site considered appears to offer major advantages over the South Inola Site proposed by the applicant as the location for the Black Fox Station, the staff concludes that the selection of the South Inola Site is reasonable and acceptable.

### 9.2.4 Transmission Line Routing

The proposed routing in the northern corridor of the western study area (as defined in the ER, Sec. 3.9) crosses a unique habitat (including a potential nesting habitat for the southern bald eagle, see Sec. 5.6.1.2) just off the BFS site. This unique habitat could be avoided by utilizing Alternative B (middle corridor), although this would result in greater visual impacts since the lines would be readily visible from several public use areas along the Verdigris River (Sec. 3.7.3). However, the staff finds that the addition of two lines supported on double-circuit steel towers near a corridor already containing five lines (supported on two parallel double-circuit steel towers and one single-circuit steel tower) will merely intensify the proposed visual impact at the Verdigris River crossing near the BFS site. In view of the fact that the proposed routing must also cross the Verdigris River on double-circuit steel towers a few miles further north, this intensification of visual impact should be outweighed by the protection of a unique habitat. The staff concludes that if these transmission lines are constructed in the proposed corridor, greater adverse terrestrial ecological impacts will result than if the alternative routing were followed. Therefore, the staff recommends that alternative route B be followed in the western study area only.

Throughout the remainder of the proposed power transmission system, the proposed route and two alternatives are not appreciably different in terms of ecological impacts. For each impact on

Table 9.15. Cost Cons.ierations Ranking of Sites

| Cost Items | Importance Factors[a] | Favorability Factor[b] And Weighted Ranking[c] Of Sites | | | |
|---|---|---|---|---|---|
| | | Oologah | S. Inola | Wagoner | N. Inola |
| Capital c.sts | | | | | |
| Land and land rights | 3 | (3) 9 | (2) 6 | (3) 9 | (4) 12 |
| Site faulting exploration | 5 | (2) 10 | (4) 20 | (4) 20 | (3) 15 |
| Clearing and grubbing | 1 | (2) 2 | (2) 2 | (2) 2 | (3) 3 |
| Foundations (excavation) | 3 | (4) 12 | (3) 9 | (3) 9 | (4) 12 |
| Flood protection | 4 | (1) 4 | (2) 8 | (4) 16 | (2) 8 |
| Railroad and bridges | 3 | (3) 9 | (3) 9 | (1) 3 | (4) 12 |
| Roadway and bridges | 3 | (1) 3 | (3) 9 | (1) 3 | (3) 9 |
| Makeup water facilities[d] | 4 | (2) 16 | (3) 24 | (3) 24 | (3) 24 |
| Cooling tower blowdown facilities[d] | 3 | (4) 24 | (2) 12 | (2) 12 | (2) 12 |
| Transmission lines[d] | 5 | (3) 30 | (2) 20 | (3) 30 | (2) 20 |
| Barge unloading facilities | 3 | (2) 6 | (3) 9 | (3) 9 | (3) 9 |
| Overland transport of reactor vessel | 5 | (5) 25 | (1) 5 | (1) 5 | (1) 5 |
| Comparative capital costs | | 150 | 133 | 142 | 141 |
| Operating costs | | | | | |
| Makeup water pumping costs[d] | 5 | (3) 30 | (1) 10 | (2) 20 | (1) 10 |
| Transmission losses | 4 | (2) 8 | (1) 4 | (1) 4 | (1) 4 |
| Ecological monitoring program | 3 | (1) 3 | (2) 6 | (2) 6 | (2) 6 |
| Comparative operating costs | | 41 | 20 | 30 | 20 |
| Comparative capital and operating costs | | 191 | 153 | 172 | 161 |

[a]Importance factors: 0 = unimportant; 1 = moderately unimportant; 2 = slightly important; 3 = m.lerately important; 4 = important; 5 = exceptionally important.

[b]Favorability factors (in parentheses): (0) = not applicable; (1) exceptionally favorable; (2) = favorable; (3) = questionable-unknowns; (4) = unfavorable; (5) = exceptionally unfavorable.

[c]Weighted ranking = product of importance factor and favorability factor.

[d]Weighted by additional factor of 2 for two units.

From ER, Table 9.3.3.

the proposed route which could be eliminated by choosing an alternative route, the impact would be increased along the alternative route. For example, the alternative routes pass about as many parks, public use areas, and other recreational areas as does the proposed route.

Based on staff consideration of potential impacts to aquatic ecosystems caused by the construction of transmission lines at stream crossings, and upon measures to mitigate possible impacts at these areas (Sec. 4), the staff finds no significant advantage in selecting the alternative routings over the reference transmission route.

## 9.3 PLANT SYSTEMS

### 9.3.1 Alternative Cooling Systems

The applicant has estimated that waste heat must be rejected by the plant at a rate of $1.62 \times 10^{10}$ Btu/hr when both units are operating at full load (ER, p. 10.1-1). In designing an acceptable method of dissipating heat at this rate, the applicable water quality standards of the State of Oklahoma must be considered.

Seven heat dissipation systems in addition to the selected circular wet mechanical-draft cooling towers (CMDCT) were considered. These were: (1) once-through cooling (OTC), (2) natural-draft wet cooling towers (NDCT), (3) conventional mechanical-draft cooling towers (MDCT), (4) wet/dry mechanical-draft cooling towers (W/D), (5) cooling ponds (CP), (6) spray canals (SC), and (7) dry mechanical-draft cooling towers (DCT). The applicant based his selection of the CMDCT on the basis of lower costs and the expressed belief that the environmental impacts of this system will be low and acceptable. The staff has considered, in addition to the alternatives above, the fan-assisted natural-draft cooling tower (FANDCT). Except for the OTC option, only closed-cycle cooling systems were considered by the staff.

The primary process for heat transfer from the circulating water to the atmosphere in wet cooling systems is evaporation. New water must be continuously added to circulating water to replace that lost by evaporation, blowdown, leaks, and drift. The use of evaporative cooling systems thus does not eliminate the need for a reliable source of water and an intake structure; when compared to OTC, it reduces but does not eliminate the environmental impacts of water intake and thermal and chemical effects of blowdown.

Closed-cycle cooling systems do not eliminate thermal emission problems; they transfer the primary impact from the hydrosphere to the atmopshere. Because such systems transfer large amounts of heat and water vapor (except for DCTs) to the atmosphere from small areas, they have a much greater potential for creating undesirable atmospheric effects than does an OTC system.

#### 9.3.1.1 Once-Through Cooling (OTC)

In OTC systems, water is drawn from a water body, circulated through the steam condenser where its temperature is raised (about 30°F or 17°C), and discharged directly into the same water body. The applicant estimates that about 2400 cfs of water would be needed to cool the two units, with a resulting temperature rise across the condensers of 30°F. Since the median flow in the Verdigris River is only 2000 cfs, the staff agrees with the applicant that OTC is not a viable cooling system for BFS.

#### 9.3.1.2 Natural-Draft Cooling Towers (NDCT)

Two large NDCTs, one for each unit, could be used to cool the station; each tower would be about 500 feet (150 m) tall with a base diameter of about 400 feet (120 m). Important advantages of NDCTs, as compared with MDCTs, are that plant power is not required to move the air and that noise levels are relatively low; the discharge height reduces the rate of ground-level drift deposition and eliminates the possibility of fogging and icing.[14-18] Major disadvantages are the relatively high capital cost and the fact that, from an esthetic standpoint, the large structures and their visible plumes tend to dominate the surroundings.

Observations at operating cooling towers in Europe, as well as in the United States, indicate that the primary environmental impacts of NDCTs are the visual impact of the structures and the generation of visible plumes that generally remain aloft,[14-18] although isolated, detached puffs of the visible plume occasionally have been observed downwind of a cluster of eight NDCTs in England.[16]

The force pulling air through the fill of an NDCT is created by the density difference between ambient air and air inside the tower. This density difference is small during periods of hot, humid weather typical of the area in summer. While NDCTs suitable for this area can be constructed, they would be larger and more expensive than those in areas with cooler, less humid summers.

The staff considers the NDCT to be a viable choice for the Black Fox site, although this type is not preferred to the selected CMDCTs because of higher capital costs (estimated by the applicant to be about $10,000,000 more than that for CMDCTs), a much greater esthetic impact, and the expected minimal offsite environmental impact of the proposed CMDCTs.

9.3.1.3 Conventional Mechanical-Draft Cooling Towers (MDCT)

In a conventional MDCT, the baffles and fans are placed in long rows. Except for one CMDCT in Mississippi, all operating MDCTs in this country have this configuration, and a considerable amount of experience has been obtained. Eight 9-cell MDCTs, each 361 feet long, 55 feet wide, 60 feet tall, and using one 200-hp motor per cell to pull the air through the fill, would be needed to cool BFS (ER, Table 10.1-1).

Due both to aerodynamic downwash effects and a lower plume rise (larger area of release of the humid air), the primary atmospheric effect created by the operation of conventional MDCTs is the formation of surface fog near the towers.[15,19-21] Whenever wind flows over an elevated structure, a region of negative pressure is formed behind the structure, and part of the visible plume is drawn into this region.[22] Observations at operating conventional MDCTs indicate that the plume at ground level due to downwash travels only a short distance (on the order of 0.5 km) before either evaporating or lifting because of buoyancy.[20,21] Downwash was observed 65% of all hours at a large MDCT in Tennessee and occurred whenever the wind speed was in excess of three meters per second (except for cases in which the wind was within ± 10° of the long axis of the tower).[20]

The applicant has used his numerical model to estimate the frequency of fog from three types of forced-draft cooling towers--CMDCTs, MDCTs, and wet/dry towers (ER, Table 10.1-4). These calculations indicate a maximum of 162 hours per year of fog due to normal dispersion 2 km from the plant (compared to 16 hr/yr at 5 km for the design CMDCTs). The frequency of fogging due to plume trapping would not be altered. However, 650 hours per year of additional fog at 0.1 km would be caused by downwash. Drift effects of MDCTs would be comparable to those from CMDCTs using similar drift eliminators.

The staff considers the conventional MDCT to be a viable cooling alternative for BFS. While more fogging and icing would occur, the increase would be mostly onsite and, in view of the rather isolated site, only small offsite impacts would be generated. Because of the greater frequency of fogging and icing (even though mostly onsite) and slightly higher costs (ER, Table 10.1-9) the staff considers the rectangular MDCT to be an acceptable but somewhat less desirable cooling option than the CMDCTs selected.

9.3.1.4 Wet-Dry Mechanical-Draft Cooling Towers (W/D)

In this type of tower, a dry-cooling section is added to a conventional MDCT. Various configurations are possible. In the design examined by the applicant, the cooling water passes first through the dry section, then the wet one. Airflow is controlled by louvers, with some of the air passing through the dry section and the rest through the wet one; the two airflows mix inside the tower prior to discharge. The resulting effluent has a higher temperature and lower humidity than that from CMDCTs or MDCTs; hence, the probability of fogging and icing near the plant is reduced but not eliminated. The amount of fog reduction is related to the relative cooling capacity of the dry and wet sections; a large dry section would be required to eliminate fogging potential completely. The W/D tower design option studied by the applicant (ER, Table 10.1-1) would have a small dry section. During the winter season, this tower would use the dry section for about 30% of the cooling capacity, and the wet section for 70% (ER, Supp. 0, Question 9.5). Four 12-cell W/D towers would be needed for BFS.

Experience with W/Ds is very limited, as only a few cells are now operational. It is expected that such towers would operate as wet-only units in summer, with both the wet and dry sections operating the rest of the year; thus, any savings in water would come in winter. W/Ds would be larger in size and more costly to build and operate than either MDCTs or NDCTs; the applicant's analysis indicates the W/Ds considered would add about $50,000,000 to the capital costs of the station (ER, Table 10.1-9).

The staff's analysis of fogging from both CMDCTs and MDCTs does not indicate a fog problem sufficient to justify the higher costs and energy usage of wet-dry cooling towers.

9.3.1.5 Fan-Assisted Natural-Draft Cooling Towers (FANDCT)

The FANDCT is a relatively new concept. In such towers, fans are used to augment the flow of air through the tower and fill. While no FANDCTs are in use or are under construction in this country, a few are in use in Europe. Two such towers, each 268 feet (81.7 m) tall, are used to cool the 1200-MWe Biblis-A nuclear power plant in Germany.[23]

A variety of FANDCT designs exist, including both cross-flow and counter-flow arrangements. In some plans, the fans can be turned off on all but the warmest days, and the unit operates as a NDCT. In others, the fans are used at all times for additive cooling capacity for a given-sized cooling tower. For example, in a typical English fossil-fired power plant, eight NDCTs (each about 374 feet, or 114 m, tall with a base diameter of 302 feet, or 92.0 m) are used to cool a 2000-MWe power complex.[8] The bulk of these towers and their visible plumes have created an esthetic impact. In an effort to reduce this impact, a single FANDCT is now being built at the 1000-MWe fossil-fired Ince "B" power plant in England;[14,24,25] this tower will be able to do the cooling of the four NDCTs it will replace. In this design, the fill will be outside the 74-foot-high shell in a typical cross-flow arrangement in a circle 564 feet (172 m) across; 35 fans will provide the necessary airflow.

The staff considers the FANDCT to be a viable cooling system from an engineering and environmental standpoint, but a less desirable choice than either MDCTs or CMDCTs, due in part to expected higher costs.

### 9.3.1.6 Cooling Ponds (CP)

The CP is a proven, effective, economical and usually environmentally acceptable heat sink in areas where enough level land can be purchased at reasonable cost. Area requirements for dissipation of waste heat via surface effects from a CP are of the order of 1 to 1.5 acres (4000 to 6000 $m^2$) per MWe.[26] On this basis, an impoundment covering about 2300 to 3500 acres (9.3 to 14 $km^2$) would be required for BFS. Additional land is required in order to eliminate the effect of steam fogs to offsite roads, buildings, etc.; a buffer zone of 1000 feet (300 m) would be satisfactory. Since the BFS site consists of only 2205 acres, the use of a CP would require the purchase of additional land.

The applicant states that while a 3500-acre cooling lake could be built on the Black Fox site with the purchase of additional land, such a cooling system would require major design changes in the plant. Specifically, the power center would have to be raised six feet to be above flood level for the CP and would cause a delay of one year in the construction of the plant.

The staff considers the cooling lake to be a viable cooling option, but with no significant environmental advantages over CMDCTs to justify the use of additional land or the delay in construction.

### 9.3.1.7 Spray Canals (SC)

The size of a CP can be made up to 20 times smaller by the use of sprays.[26] However, as with CPs, a buffer zone of about 1000 to 1500 feet (300 to 450 m) would be needed to confine fogging and drift effects to the site. Heat dissipation to the atmosphere using SCs is effected primarily through evaporation and conduction. To maximize cooling by reducing recirculation of air between sprays, the spray modules should be placed in a long, meandering canal;[27] such a canal requires a large and relatively flat area. The applicant estimates that a canal about 26,000 feet long, 200 feet wide and containing 632 floating spray modules four-abreast would be needed for proper cooling (ER, p. 10.1-7, Fig. 10.1-3).

The primary atmospheric effects of SCs are fog and drift.[28,29] Due to the larger area of contact between air and hot water, SC cooling systems have a somewhat lower potential to cause long plumes and ground-level fog than MDCTs. The drift rate from a SC will depend on factors such as wind speed and the design of the spray units; inasmuch as there are no drift eliminators, drift rates can be quite high with strong winds. However, the low height of release, low vertical velocity of the drops in the spray, and large drop size would combine to cause most of the drift to fall to the ground within a few hundred feet.[28,29]

In contrast with cooling towers and CPs, both of which have been used for decades, there has been little operating experience with large SC cooling systems, especially in winter. Experience at a power plant with an SC in northern Illinois indicates no serious fogging or other environmental problems after three seasons of operation.[30] Experience with SCs in Michigan[28,29] is similar. As with CPs, the fogging and icing effects decrease rapidly with distance. Hoffman[29] concludes that a distance of 600 feet (180 m) from the SC to public roads and switchyards is sufficient to preclude hazardous conditions. From the limited experience to date, it is reasonable to expect that SC cooling systems will create more severe icing conditions very near the canal during winter than MDCTs and CPs, with drift being the primary cause of the difference. Sprays are noisier than cooling ponds, because of the pumps, falling water, and sound energy emitted at the spray orifices.

The staff agrees with the applicant that although spray cooling could be utilized if additional land were purchased, CMDCTs are environmentally and economically preferable.

9.3.1.8 Dry Mechanical-Draft Cooling Towers (DCT)

DCTs remove heat from a circulating fluid through conduction to air being circulated past heat exchanger tubes. Because of poor heat-transfer properties of the metal-to-air interface, the tubes in DCTs are generally finned to increase the heat-transfer area. The theoretically lowest temperature that a DCT system can achieve is the dry-bulb temperature of the air. The dry-bulb temperature is always higher than, or equal to, the wet-bulb temperature, which is the theoretically lowest temperature that a wet-cooling system can achieve. As a result of the use of DCTs, turbine back pressures will be increased, as will the range of back pressures over which the turbines must operate. This, in turn, will result in a reduced station capability for a given reactor size. At BFS, back pressures would vary from 8 to 20 inches of mercury (ER, p. 10.1-3).

The major advantage of a DCT system is its ability to function without large quantities of cooling water. Theoretically, this allows power-plant siting without consideration of water availability, and eliminates thermal/chemical pollution of blowdown. In practice, some makeup water will always be required, so that power-plant siting cannot be completely independent of water availability. From an environmental and cost/benefit standpoint, DCTs can permit optimum siting with respect to environmental, safety, and load distribution criteria without fogging or dependence on a supply of cooling water. When considered as a direct alternative to wet-cooling systems, the advantages of DCTs include elimination of drift, fogging and icing problems, and blowdown disposal.

The principal disadvantage of DCTs is economic: for a given reactor size, plant capacity can be expected to decrease by about 5% to 15%, depending on ambient temperatures and assuming an optimized turbine design.[31] Bus-bar energy costs are expected to be on the order of 20% more than for an OTC system and 15% more than for a wet-cooling system, assuming 1980 operation.[31] Environmentally, the effects of heat releases from DCTs have not yet been quantified. Some air pollution problems may be encountered, noise generation problems will be more severe for mechanical-draft DCTs than for wet-cooling towers, and the esthetic impact of dry natural-draft towers (which would be much taller than equivalent wet NDCTs) will remain despite the absence of visible plumes. DCTs now being used for European and African fossil-fired plants are limited to those in the 220-MW or smaller category in areas with cool climates and winter peak loads; the use of DCTs to meet the much larger cooling requirements of 1000-MWe nuclear stations with summer peak loads requires new turbine designs to achieve optimum efficiencies at the higher peak pressure and range required of this system.[31,32]

After weighing the advantages and disadvantages of DCTs, and particularly when comparing the greater fuel consumption and the economic penalty associated with their use with the acceptable environmental impact of the proposed cooling system, the staff has concluded that DCTs are not a viable alternative for the Black Fox Station.

9.3.1.9 Conclusions

The staff considers the NDCT, FANDCT, and MDCT to be viable alternatives to the CMDCTs selected. Each of the three designs has its advantages and disadvantages in costs and environmental impacts. The staff considers that any of the above closed-cycle cooling systems could be used, but concurs that the applicant has made a reasonable choice in selecting CMDCTs.

9.3.2 Discharge System

The principal alternative to a surface discharge is a submerged one. This could be either a single-port or a multiport diffuser. Two advantages of diffuser structures are that they dilute the heated effluent to a greater extent in the vicinity of the source, and that they can prevent the plume from impinging upon the shoreline. Since plume impingement is not expected and additional dilution to meet water-quality standards will not be necessary at the BFS site, the staff believes that there is no significant advantage to using a submerged discharge.

The reference discharge wastewater holding pond, in conjunction with a shoreline surface outfall structure, will result in a small thermal and chemical plume. In addition, rip-rap will be installed and other precautions taken to prevent erosion problems at the discharge area. The surface discharge will prevent any river bottom scouring or silt mobilization from occurring as a result of BFS operation. In the opinion of the staff, no alternative design will provide significantly better protection to the environment than that proposed by the applicant.

9.3.3 Biocide System

The applicant has considered the alternative method of using sodium hypochlorite solutions rather than gaseous chlorine as a biocide. The two methods are both frequently used and the choice appears to be based mainly on local engineering and water quality conditions. The two methods of chlorination act in an identical manner and the environmental effects are similar.

Mechanical cleaning methods are applicable to condenser cleaning; however, mechanical cleaning would not reach water tunnels or water boxes, and so must be supplemented by biocidal treatment (e.g., addition of chlorine). Accordingly, this is more a technique for reducing the use of biocides than for replacing them.

Other biocides are available, such as ozone, chlorine dioxide, and bromine chloride. These materials are either unproven in cooling systems or are more expensive than chlorine, with only marginal benefits to be obtained.

The staff believes that the proposed method of handling biocides in the Black Fox Station will not result in detectable residual chlorine reaching the Verdigris River. The staff consequently believes that the applicant has made a reasonable choice of a biocidal system.

### 9.3.4 Sanitary Waste System

Because the proposed system is expected to meet EPA guidelines for municipal waste treatment effluent quality standards and Oklahoma State Department of Health and Oklahoma Water Resources Board water quality standards during operation, the staff believes other alternatives need not be considered.

### 9.3.5 Blowdown and other Chemical Discharges

Alternatives to the applicant's cooling water chemistry and blowdown disposal methods include other chemical treatments with unchanged blowdown volume, or systems to decrease or eliminate blowdown entirely.

Zero or decreased blowdown systems involve such water treatments as softening, use of additives, filtration, and final stages in which water of high solids content is evaporated to dryness. Capital and operating costs of such systems are high and they have not yet been proven in large-scale operations. In view of these factors, the staff does not presently regard this type of system as a viable alternative for the Black Fox Station.

The applicant proposes to use organic scale inhibitors to operate at a higher solids concentration (lower blowdown volume) than would be otherwise possible at non-acidic pH. However, one of the proposed scale-control chemicals contains phosphorus, the products of which can have adverse environmental effects. Furthermore, little is known about the possible toxic properties of other proposed non-phophorous anti-scalants, and adverse impacts that might result from their usage. The applicant has considered two methods that do not involve addition of scale inhibitors but rely on increased sulfuric acid concentration to control scale formation. The first method would add an additional 250 mg/l of sulfuric acid over the present 650 mg/l to control scale, and as a result the system would then be in an acidic and corrosive condition. A second method would add smaller amounts of acid but the system would then be in a scaling condition. However, mechanical cleaning and weekly high-level acid treatments would be a viable option to prevent scale buildup in lieu of using anti-scalants--such treatments are standard operating procedure at other power stations.

The applicant states that use of either of the alternative methods would be less desirable from an engineering standpoint and would probably lower system reliability. The result is therefore an expectation of higher operating costs.

The amount of chemical additives necessary to prevent scaling could be decreased by operating at a lower solids concentration and higher blowdown rate and consequently higher makeup rate. If such a system were employed, the use of a larger fraction of the river flow would be necessary, and would be environmentally less desirable.

The use of organic scale inhibitors as suggested by the applicant does have environmental advantages, such as decreased water use and a lower total use of sulfuric acid. Offsetting these known advantages, however, are uncertainties concerning possible adverse impacts that could result from their usage (see Sec. 5.3.2.2). Because of these uncertainties, the staff believes that alternatives that do not employ organic scale inhibitors should be further explored until more information is available concerning the organic inhibitors. The staff will require that this issue be resolved prior to the issuance of an operating license.

## 9.3.6 Circulating Water System

The reference design will maintain impingement and entrainment losses of aquatic organisms at levels equal to or lower than other alternative choices, e.g., spray canals, once-through cooling systems, and so forth. The staff concludes that no improvement in the total environmental cost would result from the use of alternative designs.

## 9.3.7 Intake Structure

The low water velocity expected at the intake structure (0.5 to 0.75 fps), the structure's horizontal inlet orientation, its shoreline location and mid-depth location, its proposed river-mile location, and its location in relation to other BFS structures will minimize impingement and entrainment losses of aquatic organisms. The staff has considered other commonly used intake structure designs and has also considered the possible use of other locations for placement of an intake on riparian property along the Verdigris River, and concludes that no improvement in total environmental cost would result from their use compared with that proposed by the applicant.

## 9.4 TRANSPORTATION

Alternatives, such as special routing of shipments, providing escorts in separate vehicles, adding shielding to the containers, and constructing a fuel-recovery and -fabrication plant on the site rather than shipping fuel to and from the plant, have been examined by the staff for the general case. The impact on the environment of transportation under normal or postulated accident conditions is considered not to be sufficient to justify the additional effort required to implement any of the alternatives.

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# 10. EVALUATION OF THE PROPOSED ACTION

## 10.1 UNAVOIDABLE ADVERSE ENVIRONMENTAL EFFECTS

### 10.1.1 <u>Abiotic Effects</u>

#### 10.1.1.1 Land

The construction of any large power station causes considerable disturbance to and modification of the land. The BFS will displace 2206 acres of land from other potential uses for at least the 30- to 40-year predicted lifetime of the station. Of this land about 466 acres will be disturbed during construction; however, only about half of this acreage will be permanently devoted to the station's operational buildings and other facilities exclusive of ponds, which will occupy about 70 acres. Also to be disturbed during construction are approximately 125 acres at the intake and discharge structures, and a barge slip on the Verdigris River, as well as a drainage grading area between the central complex of the site and the wastewater holding pond. Of this acreage, however, only about four acres will be permanently committed. Because of the extensive clearing, excavating, and leveling required for site preparation, subsoil will be exposed over much of the disturbed area and be subject to erosion until revegetation occurs. Chemical deposition, principally salts from the cooling towers, will occur on the site and on some of the land surrounding the site. Crop production will be lost for one season on approximately 450 acres of agricultural land located along the transmission line construction zones. There will also be a temporary displacement of cattle from about 2400 acres of such lands. After construction, however, less than 1% of the land along the ROW will be occupied by transmission tower bases and thus be unavailable for multiple use.

#### 10.1.1.2 Water

All water for station use will come from the Verdigris River. Under normal meteorological conditions, the maximum anticipated withdrawal (100% load factor) with both units operating will be 27,900 gpm, with an average rate (80% load factor) of about 22,600 gpm. This amounts to a consumptive use of water of 39,100 and 31,280 acre-feet per year for maximum and average withdrawals, respectively.

#### 10.1.1.3 Air

Construction of the station will cause some smoke and dust within a few miles of the construction areas. During station operation the cooling towers will liberate heat, moisture and particulates to the atmosphere. The particulate emissions may cause some local deterioration of air quality. The emergency diesel electric generators and boilers will release $SO_2$, particulates, and $NO_x$ during operation. However, since this equipment will operate infrequently, primarily for testing purposes, no long-term changes in air quality are expected from those sources.

#### 10.1.1.4 Noise

A detectable increase in the noise levels of the area will occur during construction. During the operational phase of the station, the cooling towers will produce a constant increase in the noise level. The staff does not expect unacceptable noise levels to occur at nearby offsite residences.

#### 10.1.1.5 Esthetics

Obvious esthetic changes will be occasioned by the presence of the plant and the approximately 225 miles of new transmission lines. Most people who see the lines will probably consider them to be esthetically unpleasing.

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### 10.1.2 Biotic Effects

Unavoidable impacts to the biotic environment that may occur due to station construction and operation are:

(a) Plant construction will remove or greatly disturb as much as 466 acres of existing terrestrial habitat on the site proper, and will cause a further reduction or alteration of biotic resources on the site or in the near vicinity. Conversely, cessation of onsite cattle grazing will eventually result in an ecological improvement of about 2200 acres.

(b) Increased salt concentrations in the soil in the local environs of the cooling towers may possibly cause minor alterations in ecological community composition.

(c) Transmission line construction may directly disturb unique communities in the rights-of-way.

(d) Bird mortality will increase slightly due to disturbances along the transmission line rights-of-way.

(e) Several small onsite ponds and their associated biota will be destroyed.

(f) Benthic organisms will be destroyed in the near vicinity of the intake and discharge structures, and the barge slip; losses will be temporary and recolonization is expected to occur.

(g) Losses of Verdigris River biota due to entrainment and impingement will occur during station operation; however, the river ecosystem as a whole is not expected to be seriously impacted.

The staff does not find that any adverse radiological consequences will occur since the radioactive effluents will be reduced to levels "as low as reasonably achievable." The estimated 500 man-rem per year received from each unit from occupational onsite exposure and estimated 1070 man-rem to the U. S. population are small fractions of the annual total dose from all sources (natural background) to the projected year 2000 population of the U. S. ($2.6 \times 10^7$ man-rem), and the risk associated with occupational exposure is considered no greater than those risks normally accepted by workers in other present-day industries.

## 10.2 RELATIONSHIP BETWEEN LOCAL SHORT-TERM USES AND LONG-TERM PRODUCTIVITY

### 10.2.1 Summary

The purpose of this section is to set forth the relationship between the proposed use of man's environment implicit in the proposed construction and operation of the nuclear generating station and the actions that could be taken to maintain and enhance the long-term productivity. It attempts to foresee the uses of the environment by succeeding generations and consider the extent to which this present use might limit or, on the contrary, enhance the range of beneficial uses in the long term.

### 10.2.2 Enhancement of Productivity

Operation of the BFS will result primarily in supplying the electrical power needed to meet projected demand. The availability of the additional electricity will have a beneficial effect on the economy and should enhance continued growth and improvement in the service areas.

The site is marginal for row-crop agriculture and is marginal to poor for grazing. Signs of overgrazing indicate that the value of the land for this use is on the decrease. Thus, commitment of this land for a nuclear power station will provide a more productive use.

### 10.2.3 Uses Adverse to Productivity

#### 10.2.3.1 Land Usage

The proposed action will remove approximately 2200 acres from cattle production. About 375 acres of the site property will be disturbed, of which about half will be modified for site facilities, including about 70 acres that will be covered by ponds. Approximately 190 acres to be used for construction facilities are expected to be returned to their previous state. Incomplete data are available concerning the expected locations of spoil disposal areas and the acreages that will be involved. The staff has estimated that because of removal of about 2200 acres from grazing at the site, the loss of profit resulting from the sale of an estimated 300 calves could be about $50,000 (1974 prices).

The installation of transmission lines is expected to have minimal impact on agriculture and grazing.

10.2.3.2 Water Usage

No groundwater will be required for plant consumption. Cooling water for the plant will be Verdigris River water, the rights to which will come from the City of Tulsa. The total annual requirement of water will be about 31,000 acre-feet under average meteorological conditions and an 80% load factor.

10.2.4 Decommissioning and Land Use

Forty years is the period for which a license to operate a nuclear power plant is issued.[1] At the end of the 40-year period the operator of a nuclear power plant must renew the license for another time period or apply for termination of the license and for authority to dismantle the facility and dispose of its components.[2] If, prior to the expiration of the operating license, technical, economic or other factors are unfavorable to continued operation of the plant, the operator may elect to apply for license termination and dismantling authority at that time. In addition, at the time of applying for a license to operate a nuclear power plant, the applicant must show that he possesses "or has reasonable assurance of obtaining the funds necessary to cover the estimated costs of permanently shutting the facility down and maintaining it in a safe condition."[3] These activities, termination of operation and plant dismantling, are generally referred to as "decommissioning."

NRC regulations do not require the applicant to submit decommissioning plans at the construction permit stage; consequently, no definite plan for the decommissioning of the BFS has been developed. At the end of the station's useful lifetime, the applicant will prepare a proposed decommissioning plan for review by the Nuclear Regulatory Commission. The plan will comply with NRC rules and regulations then in effect.

To date, experience with decommissioning of civilian nuclear power reactors is limited to six facilities which have been shut down or dismantled: Hallam Nuclear Power Facility, Carolina Virginia Tube Reactor (CVTR), Boiling Nuclear Super-heater (BONUS) Power Station, Pathfinder Reactor, Piqua Reactor, and the Elk River Reactor.

There are several alternatives which have been used in the decommissioning of reactors: (1) remove the fuel (possibly followed by decontamination procedures); seal and cap the pipes; and establish an exclusion area around the facility. The Piqua decommissioning operation was typical of this approach. (2) In addition to the steps outlined in (1), remove the superstructure and encase in concrete all radioactive portions which remain above ground. The Hallam decommissioning operation was of this type. (3) Remove the fuel, all superstructures, the reactor vessel and all contaminated equipment and facilities, and finally, fill all cavities with clean rubble topped with earth to grade level. This last procedure is being applied in decommissioning the Elk River Reactor. Alternative decommissioning procedures (1) and (2) would require long-term surveillance of the reactor site. After a final check to assure that all reactor-produced radioactivity has been removed, alternative (3) would not require any subsequent surveillance. Possible effects of erosion or flooding will be included in these considerations.

Estimated costs of decommissioning to the lowest level are about $1 million plus an annual maintenance charge on the order of $100,000.[4] In 1975 present-value terms, at 10% discount rate, this is about $48,600.

Estimates vary from case to case; a large variation arises from differing assumptions as to level of restoration. For example, complete restoration, including regrading, has been estimated to cost $70 million.[5] At present land values, consideration of an economic balance alone likely would not justify a high level of restoration. However, planning required of the applicant at this stage will ensure that variety of choice for restoration is maintained until the end of useful plant life.

The applicant anticipates retaining the BFS for power generation purposes indefinitely after the useful life of the station. The degree of dismantlement would be determined by an economic and environmental study involving the value of the land and crop value versus the complete demolition and removal of the complex. In any event, the operation will be controlled by rules and regulations in effect at the time to protect the health and safety of the public. 719 037

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## 10.3 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES

### 10.3.1 Introduction

Irreversible commitments generally concern changes set in motion by the proposed action which, at some later time, could not be altered so as to restore the present order of environmental resources. Irretrievable commitments are generally the use or consumption of resources that are neither renewable nor recoverable for subsequent use.

Commitments inherent in environmental impacts are identified in this section, whereas the main discussions of the impacts are in Sections 4 and 5. Also, commitments that involve local, long-term effects on productivity are discussed in Section 10.2.

### 10.3.2 Commitments Considered

The types of resources of concern in this case can be identified as (1) material resources, including materials of construction, renewable resource materials consumed in operation, and nonrenewable resources consumed, and (2) nonmaterial resources, including a range of beneficial uses of the environment.

Resources considered which may be irreversibly or irretrievably committed by the operation are: (1) biological resources destroyed in the vicinity, (2) construction materials that cannot be recovered and recycled with present technology, (3) materials that are rendered radioactive but cannot be decontaminated, (4) materials consumed or reduced to unrecoverable forms of waste, including uranium-235 and -238 consumed, (5) the atmosphere and water bodies used for disposal of heat and certain waste effluents, to the extent that other beneficial uses are curtailed, and (6) land areas rendered unfit for other uses. Those of importance to this project are discussed in the following sections.

### 10.3.3 Biotic Resources

The construction of the station will result in marked effects on the onsite biota, and disturbance of some of the biota adjacent to the site. The lands occupied by the station buildings, cooling towers, and ponds will be permanently altered. While restoration of some of the acreage not directly associated with the generation of electricity might be possible, the staff believes that the considerable difficulties that would be encountered makes this unlikely. Therefore, the above uses can be considered an irreversible and/or irretrievable commitment.

The reproduction potential of most species in the BFS area or along the transmission corridors is sufficiently high that losses of individuals as a result of station construction and operation will not have a long-term effect on population stability and structure of the local ecosystems.

### 10.3.4 Material Resources

#### 10.3.4.1 Materials of Construction

Materials of construction are almost entirely of the depletable category of resources. Concrete and steel constitute the bulk of these materials, but numerous other mineral resources are incorporated in the physical plant (see Table 10.1). No commitments have been made on whether these materials will be recycled when their present use terminates.

There will be a long period of time before terminal disposition of construction materials must be decided. At that time, quantities of materials in the categories of precious metals, strategic and critical materials, or resources having small natural reserves must be considered individually, and plans to recover and recycle as much of these valuable depletable resources as is practicable will depend on need.

#### 10.3.4.2 Replaceable Components and Consumable Materials

Uranium is the principal natural resource irretrievably consumed in plant operation. Other materials consumed, for practical purposes, are fuel-cladding materials, reactor-control elements, other replaceable reactor core components, chemicals used in processes such as water treatment and ion-exchanger regeneration, ion-exchanger resins, and minor quantities of materials used in maintenance and operation (see Table 10.2).

The two reactors in the plant will be fueled with uranium enriched in the isotope U-235.

Table 10.1. Material Requirements for Construction of the Proposed Black Fox Station, Units 1 and 2

| Material | Approximate Quantity Used in Plant,[a] metric tons | World Production,[a] metric tons | U. S. Consumption,[a] metric tons | U. S. Reserves,[a] metric tons |
|---|---|---|---|---|
| Aluminum | 000[b] | 9,089,000 | 4,227,000 | 8,165,000 |
| Asbestos | 90 | 2,985,000 | 712,000 | 1,800,000 |
| Beryllium | 0.6 | 288 | 308 | 72,700 |
| Cadmium | 0.0050 | 17,000 | 6,800 | 86,000 |
| Chromium | 300 | 1,590,000 | 398,000 | 2,000,000 |
| Concrete | 700,000 | -- | -- | -- |
| Copper | 4,000 | 6,616,000 | 1,905,000 | 77,564,000 |
| Gold | 0.0010 | 1,444 | 221 | 9,238 |
| Lead | 15 | 3,329,000 | 1,261,000 | 32,024,000 |
| Manganese | 800 | 7,711,000 | 1,043,000 | 907,000 |
| Mercury | 0.030 | 9,837 | 2,727 | 703 |
| Molybdenum | 5 | 64,770 | 23,420 | 2,585,000 |
| Nickel | 200 | 480,000 | 129,000 | 181,000 |
| Platinum | 0.002 | 46.5 | 16.0 | 93.3 |
| Silver | 2 | 8,989 | 5,005 | 41,057 |
| Steel | 33,000 | 574,000,000 | 128,000,000 | 2,000,000,000 |
| Tin | 0.10 | 454,000 | 82,100 | 47 |
| Tungsten | 0.010 | 35,000 | 7,300 | 79,000 |
| Zinc | 200 | 5,001,000 | 1,630,000 | 30,600,000 |

[a]Quantities used are modified from Table 10.1 of the Final Environmental Statement for Hope Creek Generating Station, Units 1 & 2, Docket Nos. 50-354 and 50-355.

[b]Data concerning proposed aluminum usage for the BFS transmission system are not available, hence total use cannot be calculated.

Table 10.2. Estimated Quantities of Materials Used in Reactor Core Replaceable Components of Water Cooled Nuclear Power Plants

| Material | Quantity Used in Plant,[a] kg | World Production,[b] metric tons | U. S. Consumption metric tons | U. S. Reserves,[b] metric tons | Strategic & Critical Material[c] |
|---|---|---|---|---|---|
| Antimony | 1.7 | 65,400 | 37,800 | 100,000[d] | Yes |
| Beryllium | 2.8 | 288 | 308 | 72,700 | Yes |
| Boron | 3,363 | 217,000[e] | 79,000[e] | $33 \times 10^6$ | No |
| Cadmium | 206 | 17,000 | 6,800 | 86,000 | Yes |
| Chromium | 109,000 | 1,590,000 | 398,000 | $2 \times 10^6$[d] | Yes |
| Cobalt | 61 | 20,200 | 6,980 | 25,000[d] | Yes |
| Gadolinium | 2,650 | 8[f] | | 14,920[g] | No |
| Iron | 443,000 | $574 \times 10^6$[h] | $128 \times 10^6$[i] | $2 \times 10^9$[d] | No |
| Nickel | 55,200<br>314,000 | 480,000[i] | 129,000[i] | 181,000[d] | Yes |
| Tin | 24,000 | 248,000 | 89,000 | 57,000[d] | Yes |
| Tungsten | 9.3 | 35,000 | 7,300 | 79,000 | Yes |
| Zirconium | 1,106,000 | 224,000[e] | 71,000 | $51 \times 10^6$ | No |

[a]Quantities used are modified from the final ER for Hope Creek Generating Station, Table 10.1, Docket Nos. 50-354 and 50-355.

[b]Production, consumption, and reserves were compiled, except as noted, from the U. S. Bureau of Mines publications "Mineral Facts and Problems" (1970 ed. Bur. Mines Bull. 650) and the "1969 Minerals Yearbook."

[c]Designated by G. A. Lincoln, "List of Strategic and Critical Materials," Office of Emergency Preparedness; Fed. Regist. 37(39):4123 (Feb. 26, 1972).

[d]World reserves are much larger than U. S. reserves.

[e]Information for 1968.

[f]Production of gadolinium is estimated for 1971 from data for total separated rare earths given by J. G. Cannon, Eng. Mining J. 173(3):187-200 (March 1972). Production and reserves of gadolinium are assumed to be proportional to the ratio of gadolinium to total rare earth content of minerals given in "Comprehensive Inorganic Chemistry," Vol 4, ed. M. C. Sneed and R. C. Brasted, D. Van Nostrand Co., Princeton, N. J., 1955, p. 153.

[g]Reserves include only those at Mountain Pass, Calif., according to the "1969 Minerals Yearbook."

[h]Excludes quantities obtained from scrap.

[i]Production of raw steel.

[j]Metallic zirconium accounted for 8% of total U. S. consumption in 1968.

After use in the plant, the fuel elements will still contain uranium-235 at slightly above the natural fraction. This enriched uranium, upon separation from plutonium and other radioactive materials (separation takes place in a chemical reprocessing plant), is available for recycling through the gaseous diffusion plant. Scrap material containing valuable quantities of uranium is also recycled through appropriate steps in the fuel production process. Fissionable plutonium recovered in the chemical reprocessing of spent fuel is valuable for fuel in power reactors.

If the two units of the plant operate at 75% of capacity for 40 years, about 14,200 metric tons of natural uranium contained in about 16,750 metric tons of $U_3O_8$ would be used to fabricate the required fuel. These values assume an irradiation level of 27,500 $MWD_{th}$/MTU when the plant is operating in its steady state. They further assume uranium recycle and an enrichment tails assay of 0.3%.

### 10.3.4.3 Uranium Resources Availability

This section reviews information available from the Energy Research and Development Administration (ERDA) on the domestic uranium resource situation and the outlook for development of additional domestic supplies, availability of foreign uranium, and the relationship of uranium supply to planned nuclear generating capacity.

Analysis of uranium resources and their availability has been carried out by the government since the late 1940s. The work was carried out for many years by the Atomic Energy Commission. The activity was made part of the Energy Research and Development Administration (ERDA) when the agency was created in early 1975.

#### U. S. Resource Position

To establish some basic concepts, a review of resource concepts and nomenclature would be worthwhile. Table 10.3 is a chart of resource categories based on varying geologic knowledge and on varying economic availability. Resources designated as ore reserves have the highest assurance regarding their magnitude and economic availability. Estimates of reserves are based on detailed sampling data, primarily from gamma ray logs of drill holes. ERDA obtains basic data from industry from its exploration effort and estimates the reserves in individual deposits. In estimating ore reserves, detailed studies of feasible mining, transportation, and milling techniques and costs are made. Consistent engineering, geologic, and economic criteria are employed. The methods used are the result of over 25 years of effort in uranium resource evaluation.

Resources that do not meet the stringent requirements of reserves are classed as potential resources. For its study of resources, ERDA subdivides potential resources into three categories: probable, possible, and speculative.[6] Probable resources are those contained within favorable trends, largely delineated by drilling, within productive uranium districts (i.e., those having more than 10 tons $U_3O_8$ production and reserves). Quantitative estimates of potential resources are made by considering the extent of the identified favorable areas and by comparing certain geologic characteristics with those associated with known ore deposits.

Possible potential resources are outside of identified mineral trends but are in geologic provinces and formations that have been productive. Speculative resources are those estimated to occur in formations or geologic provinces which have not been productive but which, based on the evaluation of available geologic data, are considered to be favorable for the occurrence of uranium deposits.

The reliability of the estimates of potential uranium resources differs for each of the three potential classes. The reliability of probable potential estimates is greatest in view of the more complete information, a result of the extensive exploration and development in the major uranium districts. It is least for speculative potential for areas with no significant uranium deposits, for which favorability is determined from available knowledge on the characteristics of the geologic environment.

Since any evaluation of resources is dependent upon the availability of information, the estimates themselves are, to a large degree, a score card on the state of development of information. Thus appraisal of United States uranium resources is heavily dependent upon the completeness of exploration efforts and the availability of subsurface geologic data. Since the geology of the United States as it relates to mineral deposits can never be completely known in detail, it will

Table 10.3. ERDA Uranium Resource Categories

| CUTOFF COST | ORE RESERVES | NURE POTENTIAL | | | ULTIMATE POTENTIAL |
|---|---|---|---|---|---|
| | | PROBABLE | POSSIBLE | SPECULATIVE | |
| | | (Known Districts-Identified Trends) | (Productive Provinces, in Productive Formations) | (New Provinces or New Formations) | |
| $8 | | | | | |
| $10 | | | | | |
| $15 | | | | | |
| $30 | | | | | |
| HIGHER COST | | | | | |

DECREASING KNOWLEDGE AND ASSURANCE →

not be possible to produce a truly complete appraisal of domestic uranium resources. Given the nature and current status of ERDA estimates, however, so far as an overall appraisal of the United States is concerned, it is more likely that the total resources eventually will prove larger than present estimates than that they will be less. The key question may be the timeliness with which resources are identified, developed and produced.

Conceptually, a resource, whether uranium or other mineral commodity, would initially be in the potential category. Development of additional data and clarification of production techniques and economics is required until the point is reached that specific ore deposits are delineated and understood to a degree that they can be categorized as reserves.

We can expect that there will be a dynamic balance between anticipated markets and prices and the extent to which exploration and reserve delineation will be done. There is no economic incentive for industry to expand reserves, if the additional uranium will not be needed for many years ahead, especially if the long-term market outlook is uncertain. This has been so for uranium. The mining companies are concentrating on markets for the next 5 to 15 years. The utilities and government are concerned with the outlook for the next 30 to 40 years. Conversion of the presently estimated potential resources into ore reserves will take many years and will cost several billion dollars. It would be difficult to economically justify accelerating such an effort to delineate ore reserve levels equal to lifetime requirements of all planned reactors covering some 30-40 years in the future simply to satisfy planners.

Supply assurance through continued timely additions to reserves and maintenance of a resource base adequate to support production demands, coupled with carefully developed information on potential resources is considered to be adequate and a more realistic and economic approach. The conversion of potential resources to ore reserves and expansion of production facilities can be accomplished when needed as markets expand and production is needed.

The vertical dimension in Table 10.3 relates to the impact of increasing production costs on resource availability. Higher prices are needed to produce ores of lower quality and those with more difficult mining or milling characteristics. Such reserves, though well delineated, are not available if prices are too low.

The domestic uranium industry has, over most of its lifetime, been concerned with discovery and production of uranium at costs in the $8-$10/lb. range or less. Average prices for uranium deliveries in 1975 are reported to be $10.50 per pound of $U_3O_8$.[7] In view of the economic acceptability of higher cost uranium in reactors, resource estimates by ERDA in recent years have included resources that would be available at $15 and $30 production cutoff costs.* However, because of the lesser experience with $15 and $30 resources, they are not as fully delineated or as well understood as the $10 resources.

At cost levels above $30 per pound, there has been little effort at appraisal of resources or in exploration. Therefore, these resources are poorly known at present and quantitative estimates are not possible (with the exception of the Chattanooga shale to be discussed later). Such resources are known to exist, and efforts are under way to appraise them.

In Table 10.4 are tabulated ERDA estimates of domestic uranium resources following the conceptual arrangement of Table 10.3. These estimates reflect the results of the preliminary phase of the ERDA National Uranium Resource Evaluation (NURE) program. The resources estimates in the preliminary phase of the NURE program totaled 3.7 million tons up to a production cost of $30. Of this 640,000 tons are in the ore reserve category. An additional estimated 140,000 tons are attributed to byproduct material through the year 2000.

Table 10.4. U.S. Uranium Resources
Tons $U_3O_8$

| | RESERVES | POTENTIAL | | | TOTAL |
|---|---|---|---|---|---|
| | | PROBABLE | POSSIBLE | SPECULATIVE | |
| $10 | 270,000 | 440,000 | 420,000 | 145,000 | 1,275,000 |
| $15 | 430,000 | 655,000 | 675,000 | 290,000 | 2,050,000 |
| $30 | 640,000 | 1,060,000 | 1,270,000 | 590,000 | 3,560,000 |
| | 140,000[a] | - | - | - | 140,000 |
| | 780,000 | 1,060,000 | 1,270,000 | 590,000 | 3,700,000 |

[a]Byproduct of phosphate and copper production.

In this evaluation program, the nation has been divided into study areas as shown in Figure 10.1. For comparison, the major known uranium areas in the U. S., such as the Colorado Plateau, Wyoming Basins and Texas Gulf Coastal Plain, are shown in Figure 10.2.

The geographic distribution of estimated potential resources is shown in Figure 10.3.

Only limited data are available for much of the country and estimates for these areas will be largely in the speculative category, or unassessed, for some time. The preliminary phase of the NURE program has identified additional areas with geologic characteristics favorable for the occurrence of uranium deposits, but for which data were inadequate for evaluation of potential resources. The locations of areas with estimated potential resources and other favorable areas are shown in Figure 10.4. The NURE program will develop considerable additional basic information, in the next several years, which will lead to a more comprehensive, in-depth evaluation of the U. S. long-term resource outlook.

## Attainable Production Levels and Reactor Capacity

The domestic industry currently has a production capacity of around 16,000 tons $U_3O_8$ per year. Plans have been reported to expand capacity to 24,000 tons per year by 1978. Study of attainable production capability from currently estimated $15 U. S. ore reserves and probable potential resources indicates that production levels of 50,000 to 60,000 tons $U_3O_8$ per year can be achieved with aggressive resource development and exploitation. While the level may be achievable by use of domestic $15 resources alone, development and utilization of $30 resources would provide added assurance that the levels could be attained and sustained. Considering that some imported uranium will add to supplies, it is considered realistic to plan on the basis that 60,000 tons per year are achievable from currently estimated resources. Such a level could be reached by the early 1990s.

*Cutoff costs are arbitrary reference costs used for resource evaluation that consider operating and future capital expenditures for mining, transporting and processing the ores. These costs are used to determine the quality limits of material to be included in a resource estimate. Cutoff costs should not be confused with prices which are determined by total cost, profit, and market place considerations.

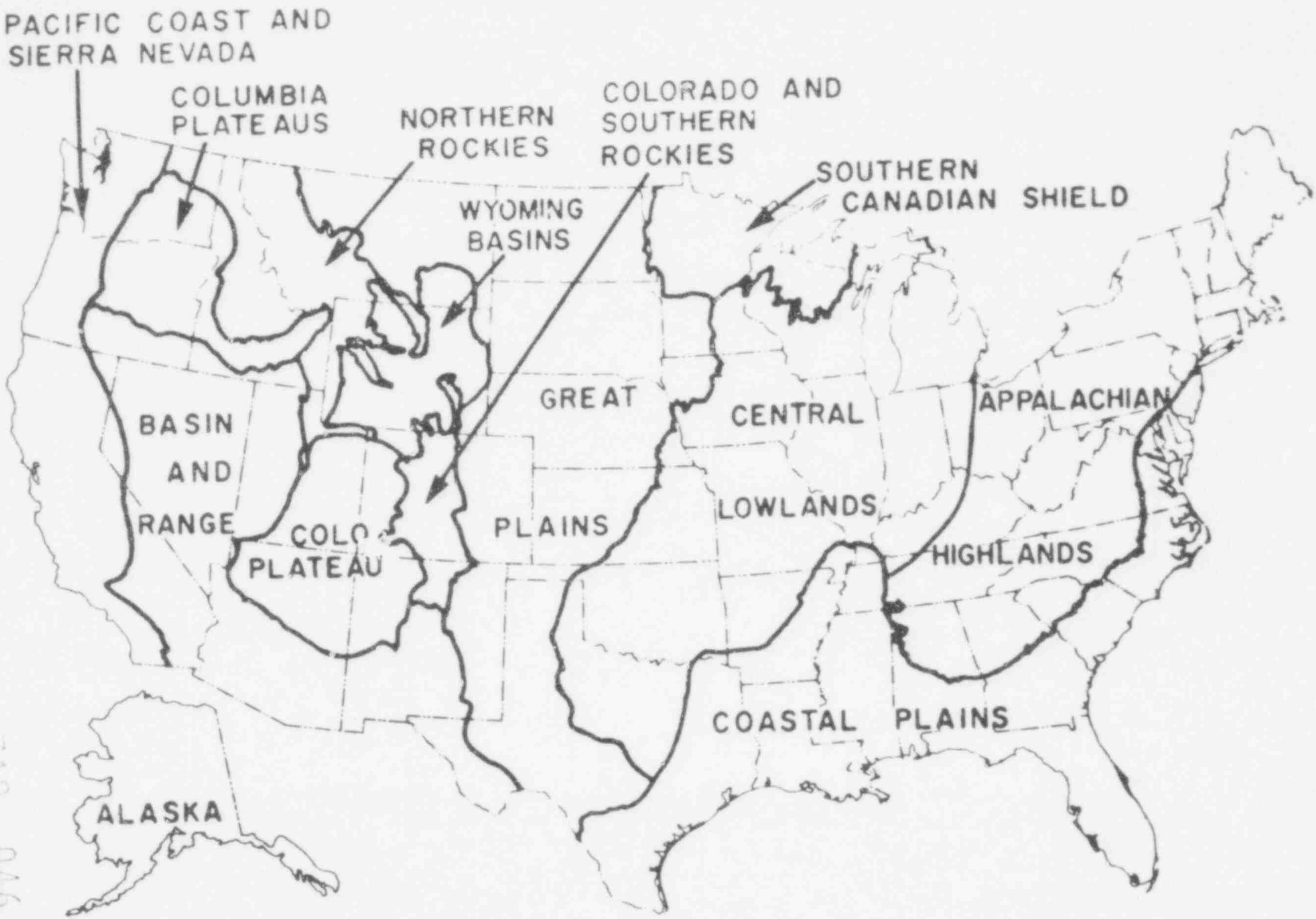



Fig. 10.1. National Uranium Resource Evaluation (NURE) Regions.


Fig. 10.2. Principal U. S. Uranium Areas.

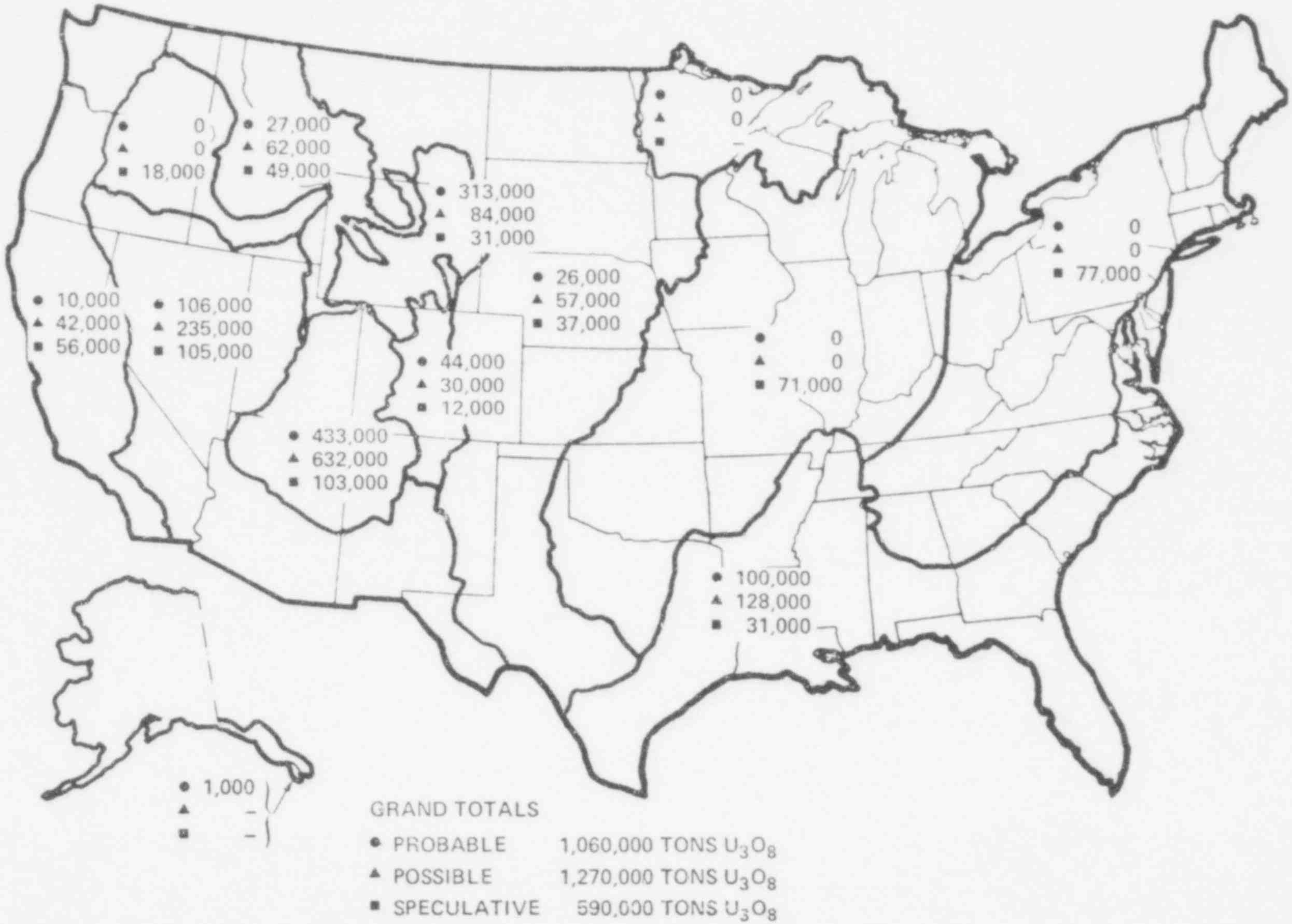
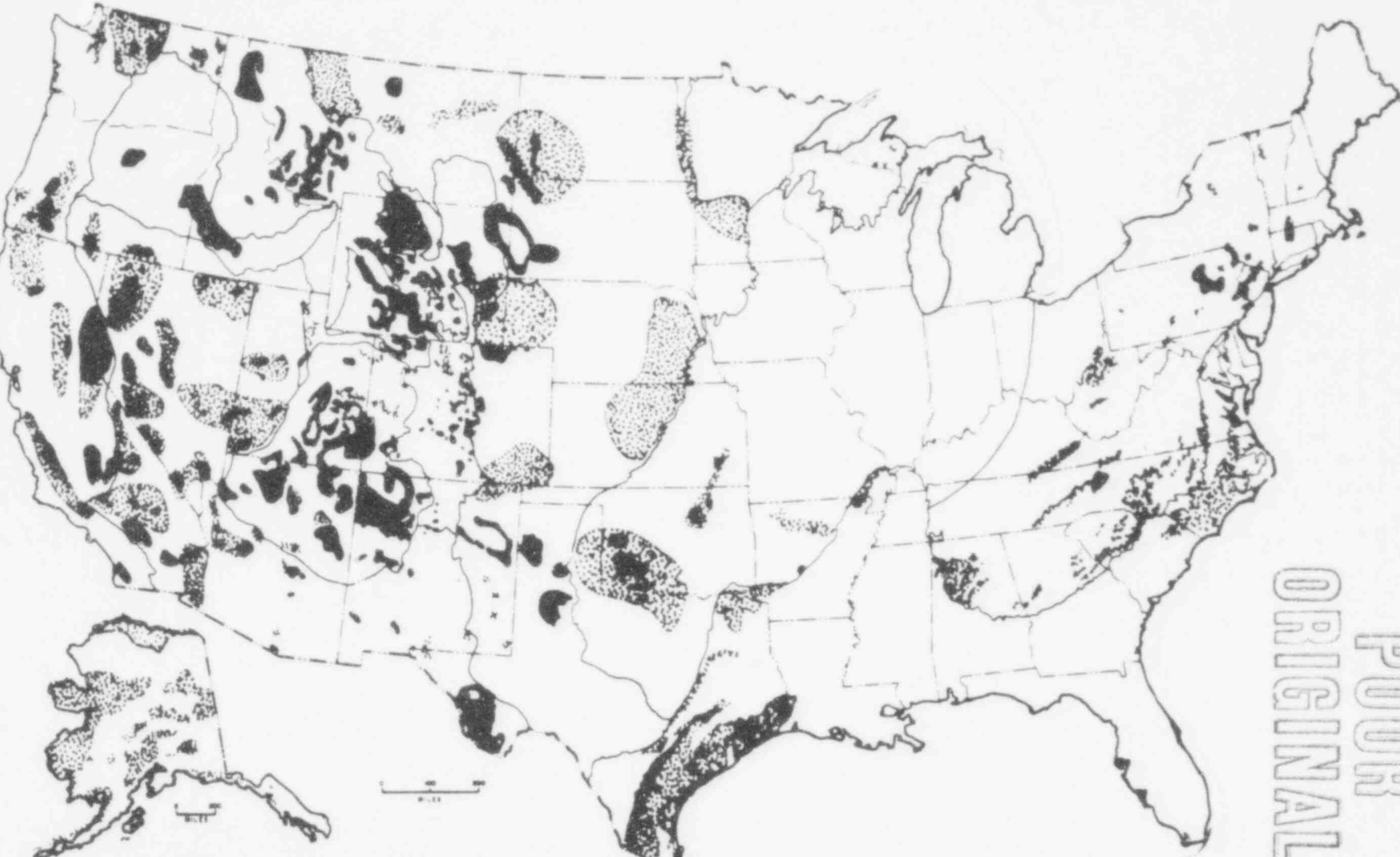



Fig. 10.3. Potential Uranium Resources by Region (\$30/lb $U_3O_8$)



PROBABLE, POSSIBLE AND SPECULATIVE POTENTIAL AREAS

OTHER AREAS WITH FAVORABLE GEOLOGY

Fig. 10.4. National Uranium Resource Evaluation Preliminary Potential and Favorable Areas.

The level of nuclear generating capacity supportable with this amount of uranium, as shown in Figure 10.5, will vary with enrichment tails assay and recycle assumptions. Without recycle of uranium or plutonium and a 0.30% U-235 enrichment tails assay, about 260,000 MWe could be supported. Without recycle, and at 0.20 tails, 310,000 MWe could be supported. With recycle of uranium and plutonium and a 0.20 tails assay, about 520,000 MWe could be supported. As shown in Figure 10.5, all the levels of supportable capacity are well above the 237,000 MWe of capacity in operation (40,000 MWe), under construction (88,000 MWe), on order (83,000 MWe), and announced (26,000 MWe) as of January 1, 1976. Thus, presently estimated resources can provide adequate uranium supplies for a sizable expansion to U. S. nuclear generating capacity.

The cumulative lifetime (30 years) uranium requirements for all these reactor cases would be about equal to the 1.8 million tons in $30 ore reserves, byproduct, and probable potential resources. Evaluation of long-term fuel commitments on the basis of ore reserves and probable potential resources is considered a prudent course for planning. The lifetime commitment would be only about half of currently estimated $30 domestic resources, including the possible and speculative categories.

While additional growth in uranium production and nuclear capacity can be supported by the possible and speculative potential resources presently estimated, a determination of supportable levels can best be made after further study and analysis of the production characteristics of all the $30 resources and after additional study of the extent of U. S. resources.

Prospects for Expanding U. S. Supply

The long-range (through the rest of the century and beyond) supply outlook will be largely influenced by the extent to which the present resource position is modified in the decades ahead. There are three principal means by which the supply position can change. First, through the identification of additional resources in the less than $30/lb category; second, through utilization of already identified higher cost resources; and third, through utilization of foreign uranium supplies. These means will be examined separately.

Domestic Low-Cost Resources

An evaluation of the potential for developing additional domestic low-cost uranium resources beyond those now estimated involves the following considerations:

1. Experience generally has been that mineral resources ultimately prove larger than can be estimated at any time. We are limited by what occurs in nature but also, and perhaps more so, by the degree of our knowledge. Development of information on unknown or poorly explored areas is likely to increase the estimate of resources. As previously noted, there is no complete assessment of the U. S. uranium position. The NURE effort is scheduled to produce a nationwide in-depth assessment in 1981.

   Comparing the U. S. uranium resource position 10 years ago with today's can illustrate the point. In 1966, $10 ore reserves were estimated to be 195,000 tons $U_3O_8$. Potential resources then estimated, which correspond to the current "probable" potential category plus a portion of the "possible" category, were 325,000 tons $U_3O_8$. Since then 134,000 tons of $U_3O_8$ have been produced. The present estimates are 270,000 tons of reserves and 440,000 tons of probable potential. Thus in the 10 years over 320,000 tons were added to these categories of resources. During the period, the value of the dollar has declined to about 60% of its 1966 value. Since inflation increases costs, moving some material to higher cost categories, the 1976 resource estimates would have been higher measured in 1966 dollars.

2. Expansion of resources will depend on the level of effort expended. Increased exploration activity can be expected to improve the resource position. Exploration success per unit of effort has been less in recent years, but inflation has exaggerated the reduction since increasingly higher grade ores must be found at a given cost to offset inflation. In addition, there has been a trend toward deeper drilling, which increases the effort required. Exploration results in 1975 show improved discovery rates.

   Industry investment activities will be influenced by nuclear power growth and acceptance, uranium demand, and price movements. As is the case of other raw materials commodities, increasing demands and higher prices should lead to increased efforts by industry to expand supplies.

3. Known U. S. uranium resources are in a few comparatively small areas as shown in Figure 10.2. The comparatively small geographic areas of the mining districts within these areas suggest that significant undiscovered districts can be overlooked.

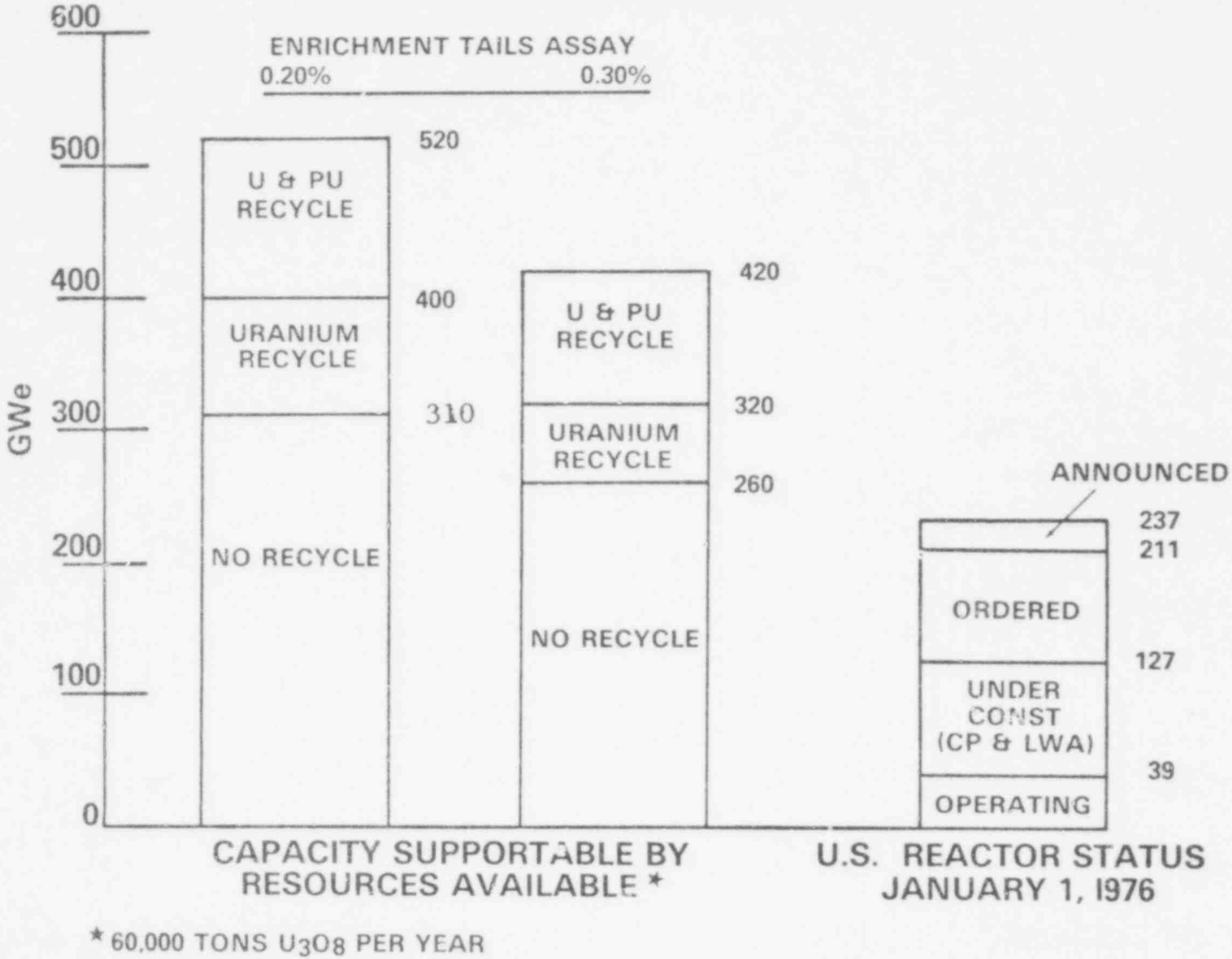



Fig. 10.5. Nuclear Reactor Capacity (GWe).

4. Domestic uranium resources in sandstone deposits make up over 95% of known U. S. low-cost resources. The bulk of resources in other parts of the world are in other types of geologic environments. A listing of significant types of uranium deposits is shown in Table 10.5. The possibility exists for identification of additional types of deposits in the U. S.

Industry Exploration Activity

The major responsibility for discovering new uranium deposits needed in the years ahead is with private industry. The footage drilled in search for uranium deposits in the U. S. for the last several years is shown in Figure 10.6. In the period 1967-69, a sharp increase in exploration occurred. Exploration decreased in the early 1970s due to softening in the uranium market as a consequence of the slippage in uranium demands. In 1973, utilities contracted for 52,000 tons of $U_3O_8$,[8] a far greater procurement effort than had been previously seen, firming prices and rekindling exploration interest. As a result, exploration began to increase again.

As shown in Figure 10.6, expenditures for land acquisition, drilling and related activities reached a peak of about $59 million in 1969, dropped to $32 million in 1972 but increased to an all time high of $122 million in 1975. Plans to expend $156 million in 1976 and $168 million in 1977 have been reported to ERDA. Although expenditures are increasing, the footage drilled per dollar of expenditure has been decreasing because of higher costs and a trend toward deeper drilling.

The results of drilling are shown at the bottom of Figure 10.6 in terms of annual additions to ore reserves. It should be noted that inflation during this period has been high, therefore, the discovery rate measured in terms of $8 reserves added in 1975 is not directly comparable to those added in 1969 and 1970. The 1969 $8 reserves are comparable in 1975 to reserves at a cost of around $15 per pound. The additions of $10, $15 and $30 reserves in the 1972-1975 period are also shown in Figure 10.6. The additions to $30 reserves increased substantially in 1975 even though not all the data from industry were available and a number of additional deposits are known to have been discovered.

Expenditures for uranium exploration have not been large in comparison to the expenditures in other phases of nuclear power. For example, the cost of a typical large reactor alone (over $800 million) will be substantially larger than the total of $520 million spent in uranium exploration (including land acquisitions, drilling and related activities) in the entire country over the period 1966 through 1975.

Technology Development

Improved technology has in the past provided a means for expanding available resources of minerals. There have been a number of developments in uranium that are improving the supply situation and others are likely to be developed in the years ahead. Of current interest is the use of in situ leaching methods where the extraction of the uranium is accomplished by pumping leach solutions down drill holes, through the ore zone, and back to the surface for treatment. Such plants are operating in Texas and others are planned.

An additional development is the improved process for recovery of uranium from phosphoric acid. A plant is starting operation in Florida, and several others are planned. If all the phosphoric acid currently produced in the large plants in Florida were treated, about 3,000 tons $U_3O_8$ per year could be recovered. Production may reach this level by the early 1980s, and future increases will follow as phosphoric acid production expands.

Government Uranium Resource Activities

In view of the need to understand better the long-range prospects for expanded domestic uranium supply for reactor development strategy and planning and to assure adequate uranium supplies to fuel nuclear power growth, the ERDA is carrying out programs to assess more completely domestic resources and to improve technology for discovery, assessment, and production of these resources. The basic elements in the ERDA resource program are illustrated in Figure 10.7.

Starting in the upper left hand corner of the diagram, knowledge about known uranium occurrences will be augmented by gathering and generating new data by use of surface, aerial, subsurface and remote sensing techniques. This will allow improved estimates in known areas and identification of other areas where known types and postulated new types of deposits may exist. This will increase knowledge about uranium occurrences in the United States, improve estimates of the resource position, and expand and solidify the base of nuclear fuel supplies. Information is

Table 10.5. Uranium Deposits

| Type | Average Deposit Grades PPM | Size Range | United States | Foreign |
|---|---|---|---|---|
| Massive Vein-like | 3,000-25,000 | 10,000-250,000 | ? | Saskatchewan, Canada; Alligator River, Australia |
| Vein | 1,000-25,000 | 1,000-40,000 | Colorado, Washington | Great Bear Lake, Canada; Shinkolobwe, Zaire; France |
| Sandstone | 500-5,000 | 100-50,000 | Colorado Plateau Wyoming, Texas | Niger, Gagon Argentine |
| Calcrete | 1,000-3,000 | 1,000-50,000 | ? | Yeelirrie, Australia |
| Quartz-Pebble Conglomerate | 200-1,500 | 10,000-200,000 | ? | Elliot Lake, Canada; Witwatersrand, South Africa |
| Alaskite | 300-400 | 75,000-150,000 | ? | Rossing, South West Africa |
| Syenite | 100-400 | 10,000-50,000 | ? | Ilimaussaq, Greenland |
| Phosphate Rock | 60-200 | 0.5-2.0 million | Florida, Idaho | North Africa |
| Shale | 50-300 | 1-5 million | S.E. United States | Ranstad, Sweden |
| Granite | 10-200 | 1-10 million | New Hampshire Colorado | Brazil |
| Sea Water | .003 | 4 billion | | |

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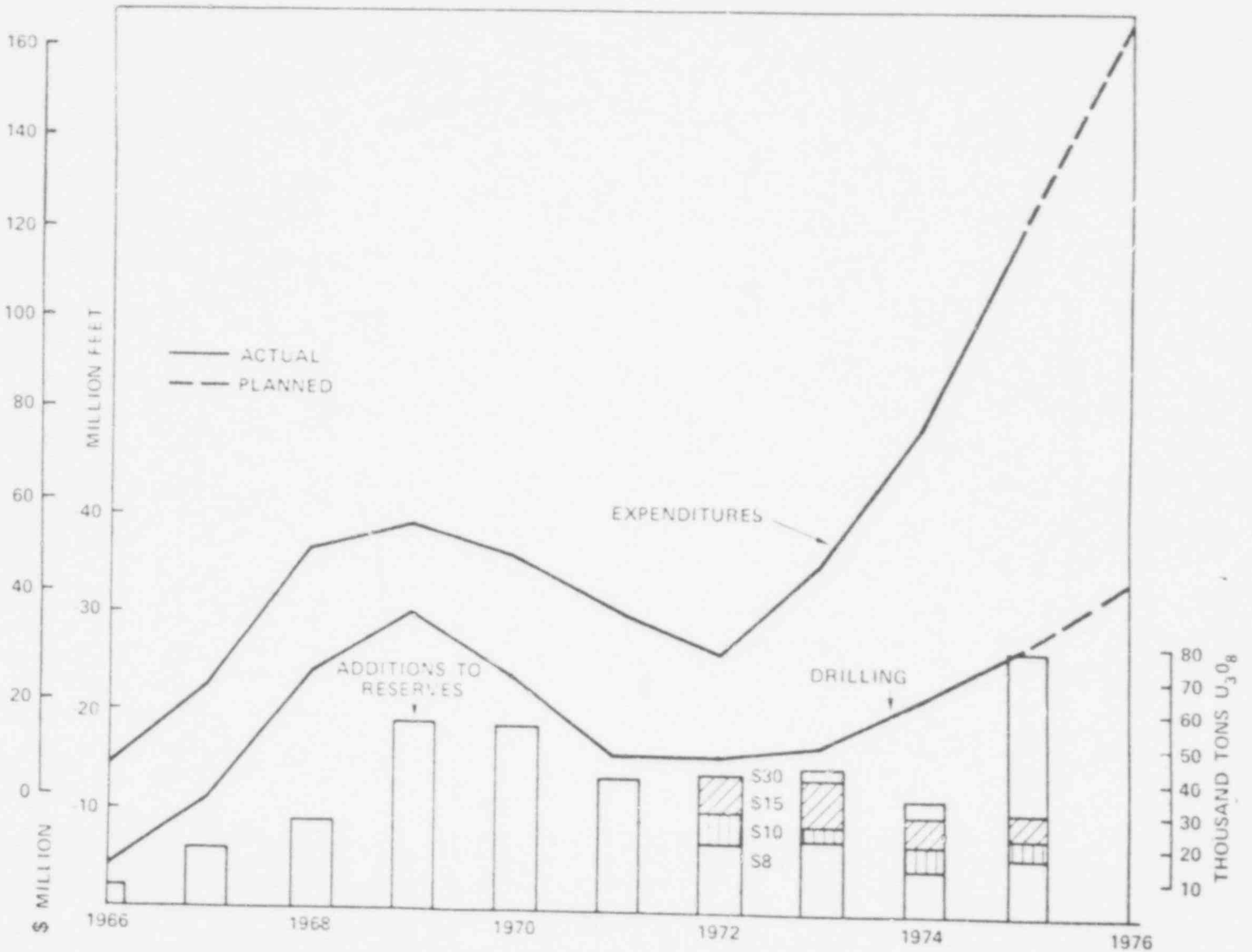


Fig. 10.6. U. S. Exploration Activity and Plans.

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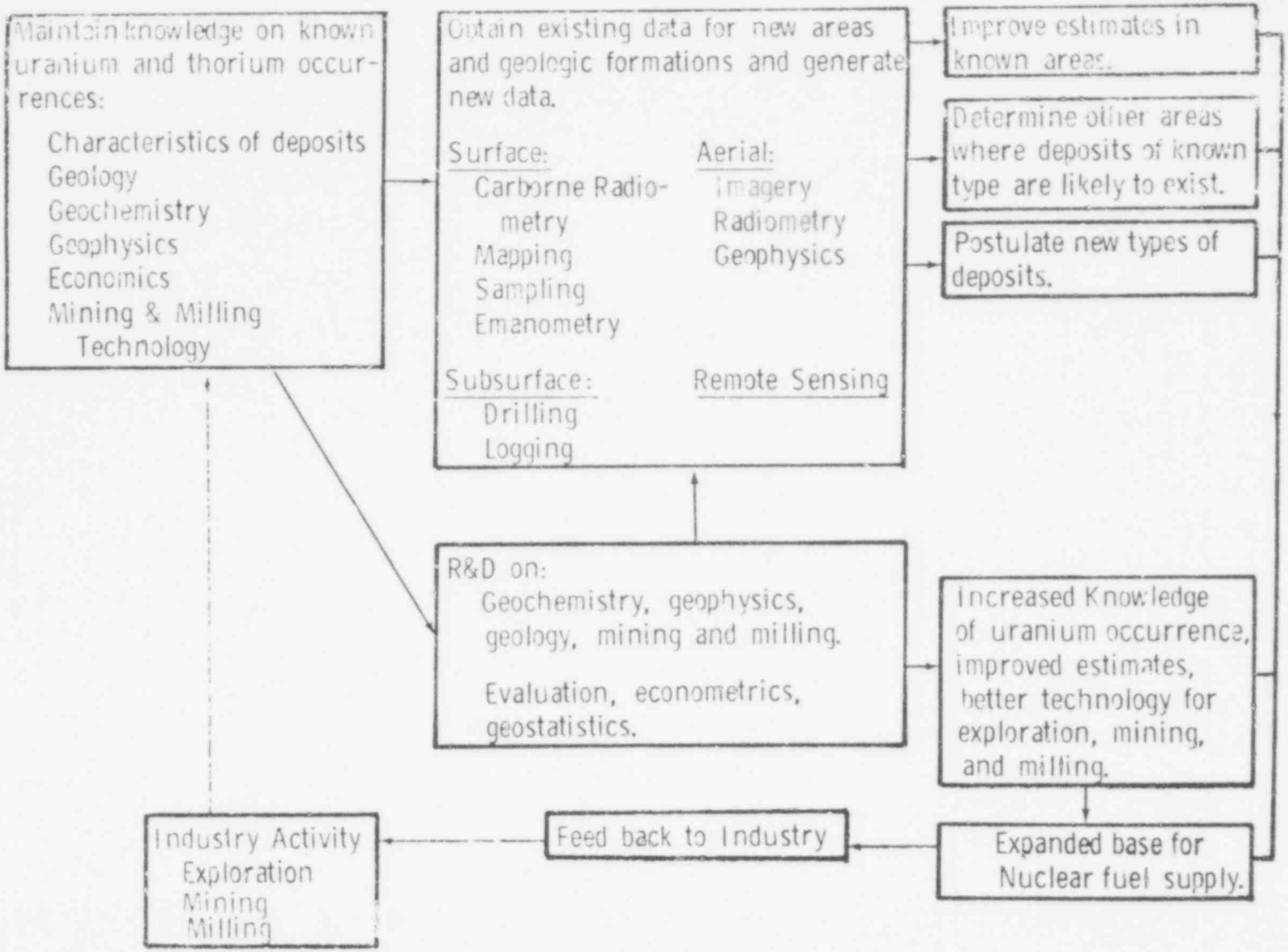


Fig. 10.7. Uranium Resource Strategy.

routinely made available to industry for development of their exploration and mining programs. Industry efforts will generate additional data which will also be used by ERDA in continuing resource studies.

An important part of this strategy is research and development to improve the technology involved in uranium discovery, assessment, mining and milling. ERDA uranium raw materials budgets to carry out this program are increasing. In FY 1976, expenditures will be around $14 million. In fiscal year 1977 $27 million has been requested.

Two activities underway to generate new data systematically are the aerial radiometric reconnaissance program and the national hydrogeochemical survey. Features of the airborne program are highlighted in Table 10.6. This program will involve some 870,000 line miles of aerial surveys flown on an average line spacing of five miles utilizing gamma ray spectrometric techniques. Data generated are being made publicly available upon the completion of individual projects.

The hydrogeochemical survey features are listed in Table 10.7. This will be a systematic national survey of the uranium and associated trace element content of surface and underground waters, being carried out by ERDA laboratories. Data generated will provide a means of identification of areas of favorability particularly when coupled with other available data.

The ERDA programs involve a continuing review of the uranium resource situation, analysis of the activities and success of industry and their relation to the desirable resource levels needed in the years ahead to assure adequate uranium supplies to meet the country's needs. The program is geared to providing information to government and industry so that sound decisions can be made on energy policy.

## High-Cost Resources

As previously noted, an alternative to identification of additional low-cost resources is the utilization of higher cost resources. The highest cutoff cost category included in ERDA resources, in Table 10.4, is $30/lb $U_3O_8$. This level was selected a few years ago as an upper range of what might be of interest for utilization in light water reactors over the next decade or more.

The increased price of oil and coal in the last few years has increased the cost of uranium economically acceptable in light water reactors. This results from the relative insensitivity of nuclear electric power costs to increases in uranium prices. The cost of fuel is only a fraction of the cost of power from a nuclear plant. In turn, the cost of natural uranium is only a fraction of the fuel cost; enrichment, fabrication, reprocessing and carrying charges make up the balance. As a result, large increases in uranium prices result in comparatively small increases in power costs. This is an important advantage for nuclear power and provides additional assurance that uranium supplies will be adequate.

Knowledge of U. S. resources in the above $30 category is meager largely because of the lack of past economic interest. There has been virtually no industry activity to search for or develop such resources. Prospects for discovery of higher cost resources in the U. S., including those types of deposits known elsewhere in the world, such as those listed in Table 10.5, are considered promising at this stage of U. S. exploration. The magnitude of such resources is, however, uncertain. The ERDA assessment program will also consider these types of resources.

There are, in addition, large very low grade deposits which have been studied in some detail in the past. These include shales, granites and phosphates.

The Chattanooga shale in Tennessee is of particular interest because of its large size. This deposit was extensively drilled, sampled, and studied in the 1950s. The higher grade part of the Chattanooga shale has a uranium content of about 60-80 ppm. It contains in excess of 5,000,000 tons of $U_3O_8$ that may be producible at a cost of $100 or more per pound of $U_3O_8$. While additional work developing production technology will be needed, it is of interest that plans have been announced to exploit a similar but considerably higher grade deposit (300 ppm) in Sweden. The mining and milling technology has been developed and the deposits are economic. A plant of 20,000 tons of ore per day capacity is planned.

Similar production technology could be used for the Chattanooga shale at higher prices. As an example, if shale were mined to fuel a 1,150 MWe reactor, assuming recycle of uranium but not plutonium and a 0.3% enrichment tail, about 12,600 tons of shale would have to be processed each day, or with uranium and plutonium recycle and 0.20% enrichment tails, about 8,500 tons per day. An average of about 11,300 tons of coal would need to be burned each day if 8,700 Btu/lb coal were used.

Table 10.6. ERDA Aerial Radiometric Reconnaissance Program

GOAL - Complete airborne radiometric survey of U.S., including Alaska, on wide-spaced flight lines, by 1-1-80, to aid in identifying favorable areas.

PROGRAM--Minimum total flight line miles--conterminous U.S., 760,000; Alaska, 110,000

FLIGHT LINE SPACING--1-12 miles: Average 5 miles

ALTITUDE--200-800 feet above ground level, optimum 400 feet

SYSTEMS--Computerized high-sensitivity gamma-ray spectrometric and magnetic detectors, mounted in fixed-wing and rotary-wing aircraft operated by private firms

OUTPUT--Radiometric equivalant of uranium, thorium, and potassium, and magnetic characteristics of enclosing rock, statistically evaluated by geologic units

DATA HANDLING

PUBLICATION--Open file upon completion of each survey

SUMMARIZED DATA BANK--Los Alamos scientific laboratory

TENTATIVE SCHEDULE

| FISCAL YEAR | LINE MILES |
|---|---|
| 1974-76 | 150,000 |
| 1977 | 147,000 |
| 1978 | 362,000 |
| 1979 | 210,000 |
| | 870,000 |

Table 10.7. Hydrogeochemical and Stream Sediment Reconnaissance Program

GOAL - A systematic determination of the distribution of uranium and associated trace elements in surface and underground waters and in stream sediments in the U.S., including Alaska, to identify areas favorable for uranium mineral occurrence.

PARTICIPANTS: National laboratories; universities; State agencies; U.S.G.S.; E.P.A.

OPERATING PARAMETERS:

SAMPLE SPACING - 10 sq. mi. (wide area) - 1/2 sq. mi. (detailed) depending on geologic homogeneity of area.

ANALYSIS - Field concentration of elements from water; measurement of conductivity and pH; determination of specific elements.

DATA TREATMENT - Statistical analysis.

DATA INTERPRETATION - Relate anomaly data to geologic environments.

OUTPUT - Areas of favorability; open-filing of maps and data; national data bank.

TENTATIVE SCHEDULE:

FISCAL YEAR - 1975 -- Literature search and limited R&D.
1976 -- Pilot studies; statistical methods development; staffing.
1977-1979 -- Large-scale surface and subsurface sampling; data analysis, interpretation, and reporting.

Utilization of the very low-grade resources such as Chattanooga shale would, of course, involve mining and processing very much larger quantities of ore than is currently mined to produce the same amount of uranium. From an environmental as well as from an economic point of view, identification and utilization of additional higher grade ores would be preferable. However, the shales are available if their use should become necessary.

## Foreign Uranium

In October 1974, the AEC announced its plan for allowing enrichment of foreign uranium intended for use in domestic reactors.[3] The plan would allow 10% of an enrichment customer's feed to be of foreign origin in 1977. The allowable percentage would increase in subsequent years as shown in Table 10.8. In 1984, there would be no restriction on use of foreign uranium. Foreign uranium, therefore, will be an additional source of uranium to meet domestic needs. During 1975, 1,100 tons of foreign uranium were delivered to U. S. buyers and 44,000 tons of foreign uranium were under contract at the beginning of 1976 for delivery to U. S. customers through 1990.[7]

Resources of foreign countries, up to the $30/lb category, are tabulated in Table 10.9. The "reasonably assured" category corresponds closely to the domestic ore reserve category and the "estimated additional" category corresponds to the domestic probable potential. As will be noted in the table, foreign resources are largely contained in five countries: Australia, Canada, South Africa, South West Africa and Sweden. All except Sweden and to some extent Canada will be essentially uranium exporting countries as their own needs will be comparatively small. The Swedish uranium is contained in low-grade shale as previously noted and is not likely to be available for export in significant quantities.

Foreign uranium demand, principally for the countries of Western Europe and Japan, is projected to grow even more rapidly than in the United States. ERDA projections indicate cumulative non-Communist foreign requirements through the year 2000 could be 2,100,000 to 2,800,000 tons of $U_3O_8$ with annual demand in 1980 of 45,000 tons and in 1990 of 90,000 to 120,000 tons (at 0.3 tails and with recycle).

Existing foreign production capacity is about 20,000 tons per year. Considering the magnitude of known foreign uranium resources and production expansion plans, foreign capability could be increased to over 50,000 tons per year in the early 1980s. Although foreign resources are large, there are limitations on attainable production levels from Canadian and South African resources, and continued growth of foreign production capability will require enlargement of the foreign resource base or use of higher cost resources.

The prospects for expansion of foreign uranium supplies from a geologic point of view are good. The experience in Australia where large new resources were identified with just a few years of effort is an example. The absence of substantial known resources in South America and in many African and Asiatic countries as seen in Figure 10.8 emphasizes the lack of exploration effort that has been done in these areas. There are, however, political limitations on the degree to which exploration will be accomplished in such places and the degree to which uranium supplies can be exported. Nationalistic policies towards resources has made access to supplies difficult in recent years. The improvement of world prices and markets should assist in opening up new areas to uranium exploration. However, since uranium demand will be low in many countries, material should be available in the world market place in time to make a useful contribution to U. S. needs.

## Fuel Cycle Practice

There are a number of management and technical decisions relating to nuclear power utilization which will have significant impact on uranium demand. An important factor relating to operation of light water reactors involves the selection of tails assay at the enrichment plants. For example, enrichment with a 0.2% tails assay instead of the 0.3% reduces uranium demand by about 20%. Recycle of uranium and plutonium would allow more efficient use of fuel and reduce demands for newly mined uranium. Successful development of a commercial breeder reactor would in time reduce growth in uranium demand. This reactor may not require any natural uranium for centuries, being able to use the several hundred thousand tons of depleted uranium which will be accumulating in the next few decades at enrichment plants. In time additional plutonium could also be available from breeders in sufficient quantities that plutonium could become the primary fuel in water reactors.

## Finding Made by the Federal Energy Resources Council

The subject of uranium availability has been considered by the Federal Energy Resources Council which had participation by the Council on Environmental Quality, the Department of Commerce,

Table 10.8. Allowable Foreign Uranium Enrichment Feed (Domestic End Use)

Tons $U_3O_8$

| Calendar Years | Schedule of Percentage of Feed Allowed to be Foreign |
|---|---|
| 1974 | 0 |
| 1975 | 0 |
| 1976 | 0 |
| 1977 | 10% |
| 1978 | 15% |
| 1979 | 20% |
| 1980 | 30% |
| 1981 | 40% |
| 1982 | 60% |
| 1983 | 80% |
| 1984 | No Restriction |

Table 10.9. Foreign Resources
Thousand Tons $U_3O_8$

| | Reasonably Assured | Estimated Additional |
|---|---|---|
| | $15/Lb $U_3O_8$ | |
| Australia | 430 | 104 |
| S & SW Africa | 242 | 8 |
| Canada | 189 | 394 |
| Niger | 52 | 26 |
| France | 48 | 33 |
| Algeria | 36 | -- |
| Gabon | 26 | 6 |
| Spain | 13 | 1 |
| Argentina | 12 | 20 |
| Other | 56[a] | 26 |
| Total (Rounded) | 1,100 | 630 |
| | $30/Lb $U_3O_8$ | |
| Australia | 430 | 104 |
| Sweden | 390 | -- |
| S & SW Africa | 359 | 96 |
| Canada | 225 | 887 |
| France | 71 | 52 |
| Niger | 65 | 39 |
| Algeria | 36 | -- |
| Spain | 30 | 55 |
| Argentina | 27 | 50 |
| Other | 150[b] | 110 |
| Total (Rounded) | 1,780 | 1,390 |

[a]Includes Brazil, Central African Republic, Germany, India, Japan, Mexico, Portugal, Turkey, Yugoslavia and Zaire.

[b]Includes, in addition to a/, Denmark, Finland, Italy, Korea and the United Kingdom.

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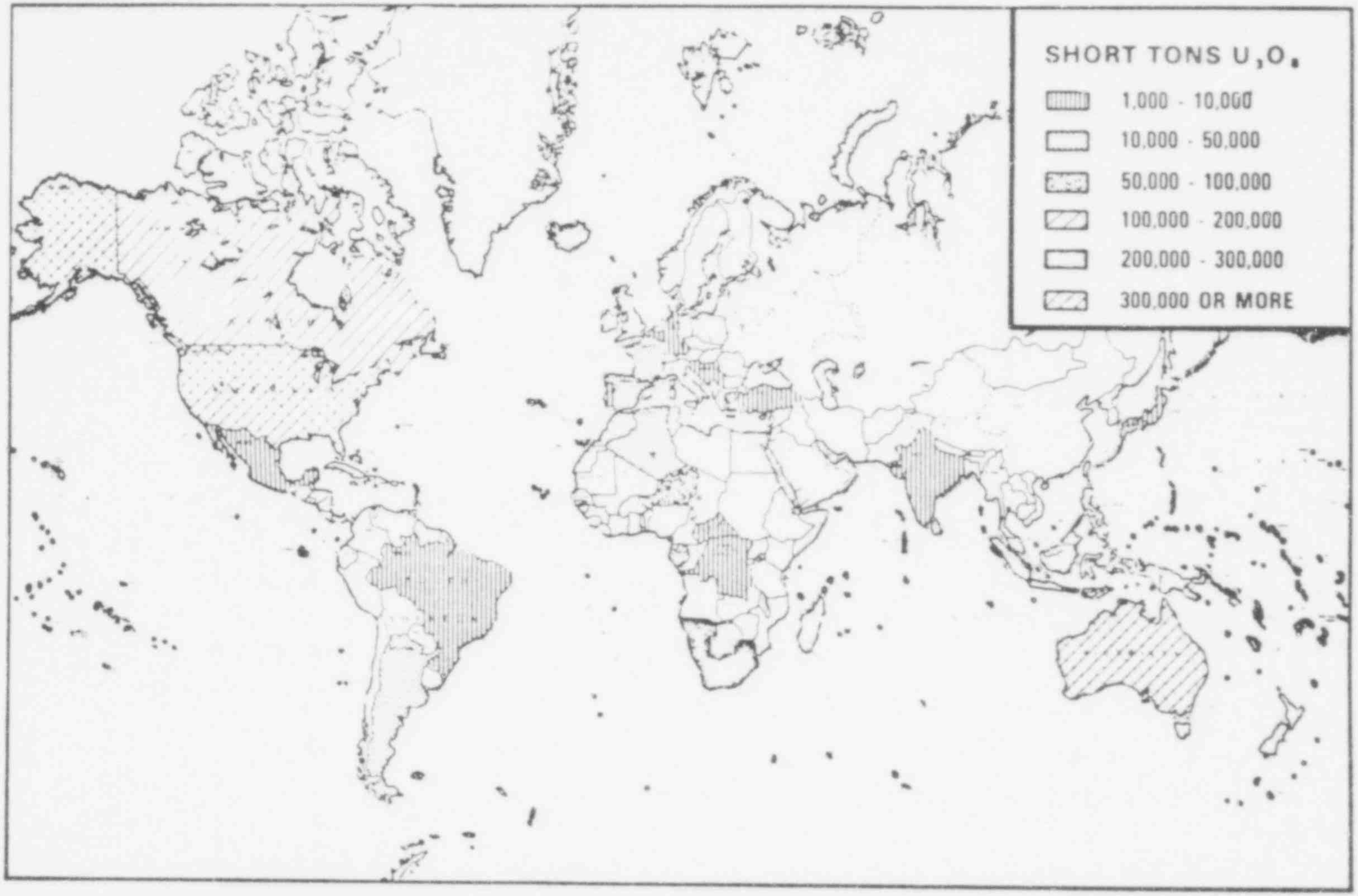


**EXCLUDES PEOPLES REPUBLIC OF CHINA, USSR AND ASSOCIATED STATES OF EASTERN EUROPE**

Fig. 10.8. World Uranium Resources Reasonably Assured Reserves @ \$15 Per Pound $U_3O_8$.

POOR ORIGINAL

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Department of Interior (U. S. Geological Survey), Environmental Protection Agency, ERDA, and FEA. A report issued by the Council, "Reserves, Resources and Production," June 15, 1976, states "available data indicates that there are sufficient economically recoverable uranium resources on which to base an expanding national program. The adequacy of uranium to provide fuel (over their 30-year lifetime) for all existing plants and additional reactors which may be placed into service by 1990 is a reasonable planning assumption."

Conclusion

In conclusion, ERDA assessment of uranium resources indicates that currently estimated U. S. resources would be adequate to allow fueling of substantially more nuclear power plants than all those now operable, under construction, on order and announced, without recycle of uranium or plutonium and with high enrichment tails assays. Lower tails assays and recycle could significantly increase the supportable capacity. Further expansion of U. S. uranium supplies is possible by discovery of new low-cost resources, utilization of higher cost resources or importation of foreign uranium. ERDA programs are designed to improve understanding of current resources and to aid in identification of new resources, seeking to assure that uranium supplies will be available when needed.

Prices have increased to levels that make exploration and production economically attractive. Industry exploration and development activities are increasing. Foreign uranium supplies will be available to augment domestic resources. There is a high probability that additional intermediate cost resources can also be identified and there are known domestic high cost resources which could be used if needed.

10.3.4.4 Geologic Resources

One producing oil well and two producing gas wells will be sealed for the life of the plant. Annual production losses will be approximately 180 barrels of oil and 55,000 mcf of gas. These amounts are miniscule compared with the total annual production in the State of Oklahoma.

10.3.5 Land Resources

About 2206 acres of land would be committed to the construction and operation of the power station for the time the plant is licensed to operate. At the present time, all but about 15 acres of the site are used for cattle grazing. Land commitment is potentially reversible except for that occupied by the reactor building itself. The amount of commitment is a function of the level of decommissioning chosen (see Sec. 10.2.4); however, the applicant expects to retain the site indefinitely.

The BFS site lies along a portion of the Verdigris River used as a navigation channel. The operating station will not affect navigation in any way.

At the onset of construction, any use of the BFS site for recreation (hunting, fishing) will cease for the life of the station.

10.3.6 Energy Resources

10.3.6.1 Net Energy Yield from Nuclear Power Plants

Recently, a considerable amount of interest has developed regarding the energy investment required to construct and operate a nuclear power plant relative to the amount of energy generated by the plant over its operating life. Some critics of nuclear power have indicated that more energy is expended in constructing and operating a nuclear plant than will be produced by the plant.

In order to assess this issue, the staff has, on an independent basis, estimated the energy consumed in constructing a nuclear power plant and the energy expenditure in producing the nuclear fuel required by the plant during its operating lifetime.

The following analysis compares the thermal energy investment requirement for the construction and operation of a single-unit nuclear power plant with the total thermal energy output of a 1000-MWe nuclear plant operating at a heat rate of 10,000 Btu/kWhr and an annual capacity factor of 70% for a 30-year operating life.

10.3.6.2 Introduction

The sum of energy inputs for plant construction and nuclear fuel mining, milling, production of uranium hexafluoride, enrichment, fabrication, and reprocessing was compared with the thermal energy generated by the nuclear plant over its operating lifetime. The staff elected to compare the total value of the input heat energies of the primary fuels rather than the actual work energy of any of the processes. This was done in order that the effect of thermodynamic inefficiencies of heat engines would be eliminated from the calculations and thus would not bias the comparison of energy input with output for a nuclear plant. For example, rather than considering the heat content of the electricity produced by a nuclear plant, it was decided to look at the heat generated by the nuclear reactor without the inherent inefficiencies of converting this heat energy into electricity. Similarly, when electricity was required in the construction of the plant or the fabrication of nuclear fuel, this electricity was converted into the equivalent primary energy required to generate the electricity rather than the heat content of electricity.

10.3.6.3 Energy Required for Plant Construction

Material

The method used to determine the energy required to construct a nuclear plant was based on the quantities of various materials contained in a nuclear power plant and the energy used at the plant site in constructing the equipment.

Estimates of the quantity of materials contained in a light-water nuclear power plant have been made by Bechtel Power Corporation, Oak Ridge National Laboratory, United Engineers and Constructors, and Burns & Roe. These estimates are summarized in Table 10.10.

Table 10.10 Estimates of Quantites of Materials Contained in LWR Nuclear Plant

| | Bechtel[a] | ORNL[b] | United Engineers[c] | Burns & Roe[d] |
|---|---|---|---|---|
| Unit electrical rating, MWe | 1100 | 1000 | 1000 | 1000 |
| Number of units | 1 | 1 | 1 | 1 |
| Type of nuclear steam system | PWR | PWR | PWR | LWR |
| Type of cooling system | Natural draft cooling tower[e] | Once-through | Once-through | Once-through |
| Architect-engineer | Bechtel | United Engineers | United Engineers | Burns & Roe |
| Material | | | | |
| Steel, thousands of tons | | | | |
| Structural | 31 | 36 | 7 | 5 |
| Reinforcing | 12 | | 15 | 17 |
| Piping[f] | | | 6 | 7 |
| Miscellaneous | 12 | 4 | | |
| Total steel | 55 | 40 | 28 | 29 |
| Concrete, thousands of cubic yards | 300 | 98 | 150 | 175 |
| Wood, millions of board feet | 20 | 4.8 | 1.5 | 2 |

[a]Data based on a study performed by W. K. Davis, Bechtel Power Corp.

[b]Data based on *Estimated Quantities of Materials Contained in a 1,000 MW(e) ::R Power Plant*, ORNL-TM-4515, by R. H. Bryan and I. T. Dudley, June 1974.

[c]Memorandum from John H. Crowley, Manager, Advanced Engineering Department, United Engineers & Constructors, to Dr. Shelby T. Brewer, Division of Reactor Research and Development, U.S. Atomic Energy Commission, May 21, 1974.

[d]Data based on Burns & Roe study for LMFBR project.

[e]A typical natural-draft cooling tower contains about 10,000 cu yd of concrete and 750 tons of reinforcing steel.

[f]When piping data were given in linear feet, it was assumed that the average weight of the pipe in the plant was 50 lb/ft.

Of the four estimates made by Bechtel, ORNL, United Engineers, and Burns & Roe, the Bechtel estimate had the largest amounts of materials required to build an 1100-MWe nuclear plant. The Bechtel estimate of materials was chosen for use in the staff's calculations for that reason. In addition to the material requirements for steel, concrete, and wood, the ORNL estimate indicated a need for aluminum and copper in constructing a nuclear power plant. Thus, in the staff's calculations, the ORNL estimates for aluminum and copper were also included.

A composite estimate of material requirements, based on the Bechtel and ORNL studies, is shown in Table 10.11. All of the material estimates have been converted into tons of raw materials.

Table 10.11 Energy Investment in 1100-MWe PWR

Total Energy Investment, $5.6 \times 10^{12}$ Btu

| | Estimated quantity of Material Contained in 1100-MWe PWR (tons) | Average process Energy Requirement[a] (millions of Btu per ton) | Energy Consumption (billions of Btu) |
|---|---|---|---|
| Steel | 55,000 | 26.5 | 1457 |
| Cement | 135,000[b] | 6.6 | 890 |
| Wood | 33,000[c] | 29 | 1287 |
| Aluminum | 500 | 155 | 77 |
| Copper | 4,000 | 47 | 188 |

[a]Data obtained from *Potential Fuel Effectiveness in Industry*, by E. P. Byfropoulos, L. J. Lazaridis, and T. F. Widmer, 1974.

[b]Assumes that density of cement is 1.35 tons/cu yd and that cement makes up about one-third of the concrete.

[c]Assumes that density of wood is 40 lb/cu ft.

The second column in Table 10.11 shows the average amount of energy expended to manufacture a ton of each of the materials listed. These energy requirements are based on historical experience and do not take into account any technological advances which might lower the average energy requirement to produce a ton of any given material. Based on these figures, it can be estimated that the construction of a nuclear power plant will require about $5.6 \times 10^{12}$ Btu. This energy would account for the manufacturing of materials to be used in the plant.

Fuel Used During Construction

The second category of energy consumption which must be considered is the electricity and fuel consumed at the plant site during the construction period. This energy could be consumed in operating heavy equipment, welding, lighting, transportation, and other processes and includes energy from gasoline, diesel fuel, and electricity.

Seven different estimates of the amount of energy to be consumed at plant sites during construction were obtained and are tabulated below. Considering the number of units at each site, the staff took as a reasonable assumption that a single 1000-MWe unit would require one trillion Btu of energy during the construction period.

| Name of Plant or Study | Total Energy Consumption ($10^{12}$ Btu) |
|---|---|
| Bechtel (1 unit) | 0.97 |
| River Bend (2 units) | 1.42 |
| Greenwood (2 units) | 1.8 |
| Barton (4 units) | 2.18 |
| Tyrone (2 units) | 1.3 |
| Koshkonong (2 units) | 1.14 |
| Davis-Besse (2 units) | 1.0 |

Secondary and higher order energy effects of constructing and operating a nuclear plant, such as the energy required to build steel mills or a cement manufacturing facility, appear to be minor. The most significant of these secondary effects would result from the uranium enrichment process, which utilizes the electricity from coal-fired steam electric power plants. Rombough and Koen have estimated in their article "Total Energy Investment in Nuclear Power Plants" (*Nuclear Technology*, May 1975) that the secondary energy requirements for the operation of gaseous diffusion enrichment plants would increase total energy input for the construction and operation of a nuclear plant by about 8% (for deep-mined coal), which would increase the energy required to construct and operate a nuclear plant from 6% to 6.4% of the plant's production capability. Secondary effects for other components of nuclear plant construction and operation would be considerably less than for the enrichment plants.

10.3.6.4 Energy Required for Nuclear Fuel Cycle

Nuclear Fuel

The principal requirement for energy in the fuel cycle of a light-water reactor is for enriching uranium. A nuclear power plant having a capacity of 1000 MWe will require on the order of 200,000 separative work units to enrich the uranium in the initial core and on the order of 100,000 separative work units per year to enrich the uranium in replacement loadings after allowing for the recovery of uranium in spent fuel. These requirements vary with type of reactor (pressurized water or boiling water), reactor operations, and assay of uranium tails from the enriching facilities.

The existing gaseous diffusion plants for enriching uranium, when operated at full power, consume about 3100 kWhr of electrical energy per separative work unit. Application of the cascade improvement and cascade uprating programs to these plants will reduce the consumption of electrical energy to about 2300 kWhr per separative work unit (see Fig. 3 on p. 39 of ERDA report CONF-750209 on the uranium enrichment conference of February 13-14, 1975, at Oak Ridge, Tennessee). The centrifuge method of enrichment would require much less electrical energy. For the calculation below, the conservative figure of 3100 kWhr is used.

The energy requirements for operating uranium enrichment facilities to provide fuel for a 1000-MWe nuclear power plant are, therefore, approximately 620,000,000 kWhr of electrical energy for the initial core and 310,000,000 kWhr per year for replacement loadings. Additional energy requirements for operating other facilities in the uranium fuel cycle involved in mining, milling, production of uranium hexafluoride, fuel fabrication, reprocessing, and waste management would bring the total to about 330,000,000 kWhr per year for replacement loadings. This includes the electrical energy that could have been produced from the natural gas used for process heating (see Table S-3A on p. S-13 of AEC report WASH-1248 of April 1974 on *Environmental Survey of the Uranium Fuel Cycle*). The equivalent heat energy for the initial core and the replacement loads are 6.7 trillion and 3.3 trillion Btu, respectively.

Nuclear Fuel Facilities

In addition to the energy required to produce the nuclear fuel, energy is consumed in constructing facilities used in fuel-cycle operations, such as mines, mills, and plants for fluorination, enrichment, fuel fabrication, and chemical reprocessing of uranium. Dollar investments in such

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facilities relative to the investment in the nuclear power plant itself may be obtained from Table V on p. 52 of an article on "Nuclear Fuel Logistics" by S. Golen and Ra. Salomon in *Nuclear News* for February 1973. The investments in these facilities are apportioned according to the fraction of their capacity required to service a 1000-MWe nuclear power plant. The lower end o the range of useful lives for the various facilities is assumed, namely, 30 years for the nuclear power plant; 10 years for uranium exploration, mining, and milling; 15 years for uranium purification and fluorination, fuel fabrication, and chemical reprocessing and 20 years for uranium enrichment. The results are that the dollar investment in the nuclear power plant should be supplemented by about 11% initially to cover the cost of fuel-cycle facilities and by about 1.5% after 10 years to cover the cost of replacement facilities. It is then assumed that the energy investment in these facilities is proportional to the dollar investment, so that the energy investment in the nuclear power plant should be increased by the same percentages. It had previously been estimated that the total energy requirement to construct a single-unit nuclear plant is about 5.6 trillion Btu. Thus, the energy consumed in constructing facilities used in the fuel cycle would amount to 0.6 trillion Btu initially, 0.1 trillion Btu after the 10th and the 15th year of nuclear power plant operation, and 0.3 trillion Btu after the 20th year of power plant operation.

10.3.6.5 Summary

In comparing energy inputs and outputs, the inherent thermal inefficiencies associated with converting heat energy into electricity were not considered. That is, the energy output of a nuclear plant was considered to be the heat energy generated by the fission process rather than the heat content of electricity. Similarly, when electricity was required for the construction or operation of the nuclear plant, the staff calculated the primary energy required to generate the electricity. By using this energy accounting procedure, the staff did not compare energies of different qualities and, therefore, eliminated the effects of the second law of thermodynamics on the overall energy balance.

The total energy requirement to construct a single-unit nuclear plant amounts to about 5.6 trillion Btu for the manufacturing of material such as steel, cement, and wood and 1 trillion Btu for fuel used during plant construction. The bulk of the energy requirement for a nuclear power plant can be attributed to the nuclear fuel cycle, which accounts for approximately 104 trillion Btu. Of this amount, about 96 trillion Btu, or 87% of the total energy investment, is used in the gaseous diffusion plants for enriching uranium. Only a minor fraction, about 0.9%, is needed to construct nuclear fuel mining and manufacturing facilities.

The initial nuclear fuel core requires about 6.7 trillion Btu, and nuclear fuel mining and manufacturing facilities require an additional 0.6 trillion Btu. The total amount of energy required to initially construct and operate a single-unit nuclear plant during its first year of operation equals approximately 13.9 trillion Btu.

Nuclear fuel replacement cores require about 3.3 trillion Btu annually for each year of power plant operation after the initial year. The rebuilding of facilities required to mine and manufacture the nuclear fuel will require approximately 0.1 trillion Btu after the 10th and 15th year of power plant operation and about 0.3 trillion Btu and after the 20th year of power plant operation.

The total amount of energy expended over a 30-year lifetime of a single-unit nuclear power plant, including all of the categories mentioned above, amounts to approximately 110 trillion Btu. By comparison, a single-unit 1000-MWe nuclear power plant will generate 1840 trillion Btu during its lifetime if operated at a 70% capacity factor and at a heat rate of 10,000 Btu/kWhr. Thus, the thermal energy required to build and operate a nuclear power plant equals only about 6% of the thermal energy output of the plant.

Figures 10.9 and 10.10 show a comparison of the thermal energy produced by a nuclear power plant with the thermal energy required to construct and operate the plant as a function of time. As seen in Fig. 10.9, the total energy produced by a single-unit 1000-MWe nuclear plant is about 17 times the energy input for construction and operation of the facility. Figure 10.10 presents a more detailed picture of the early months of plant operation. As seen in the figure, after about three months of commercial operation, the nuclear plant has produced enough energy to equal all of the energy required to construct and fuel the power plant. At this point, the nuclear plant will begin to produce about 19 times as much energy annually as will be required to continue plant operation.

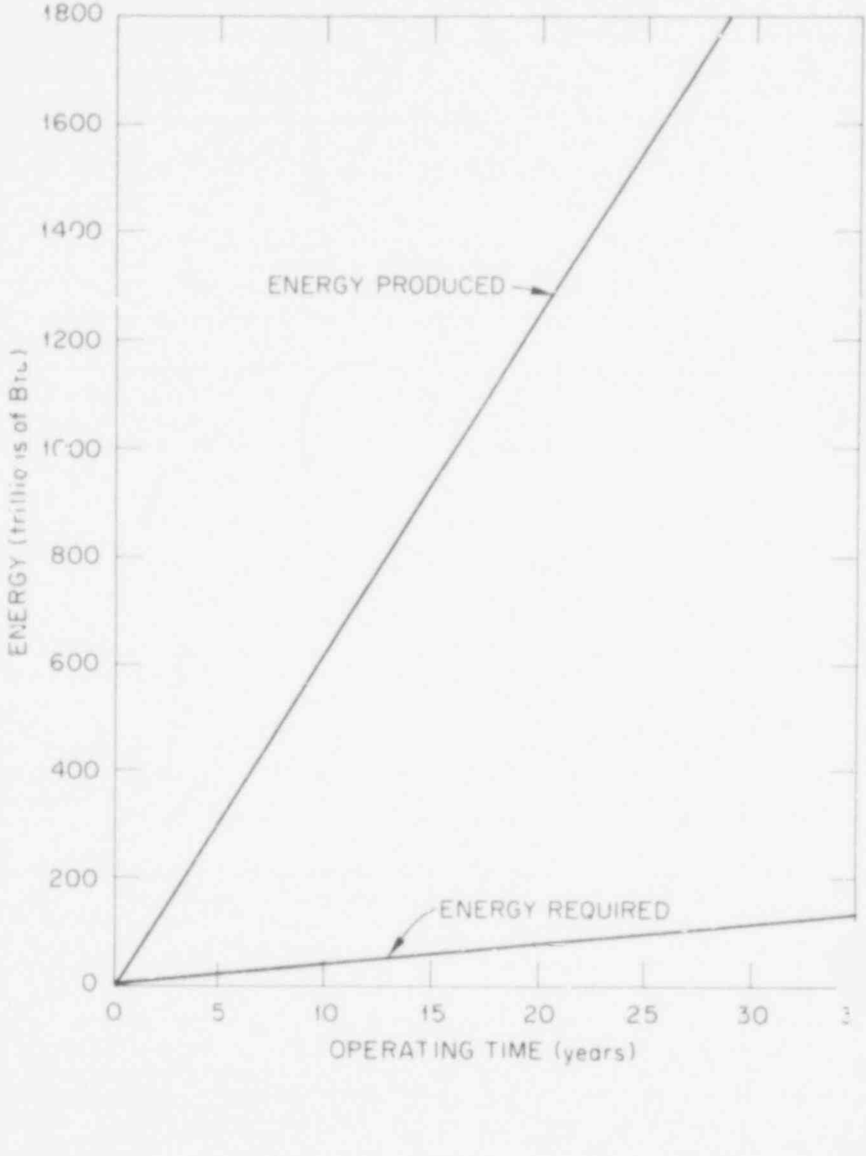


Fig. 10.9 Thermal Energy Produced and Required to Construct and Operate a 1000-MWe Nuclear Plant.

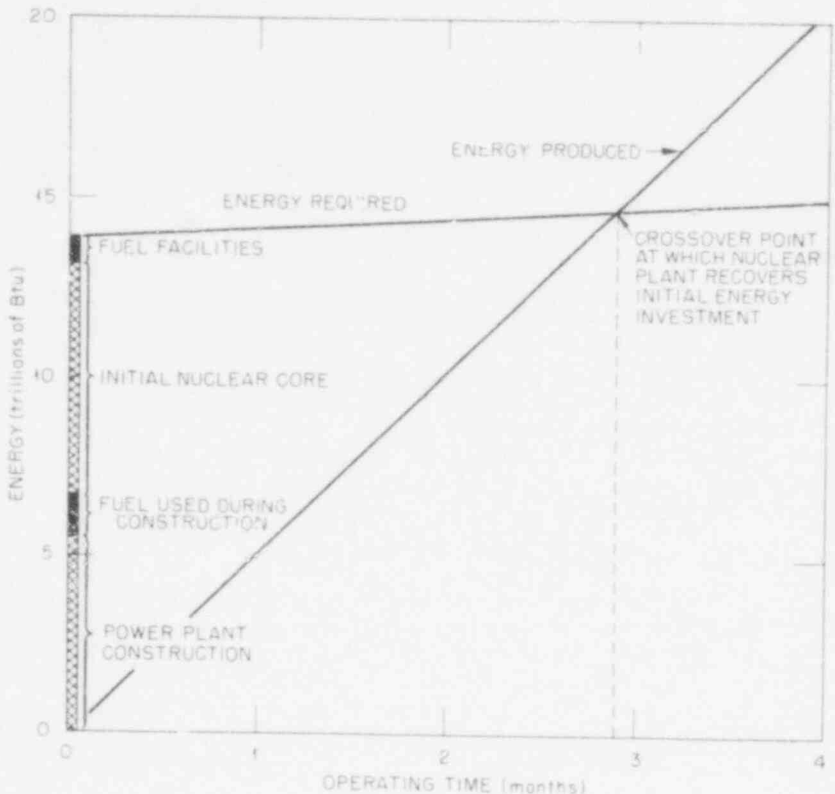


Fig. 10.10 Thermal Energy Produced and Required During Early Months of Commercial Operation of a 1000-MWe Nuclear Plant.

10.3.6.6 Institute for Energy Analysis Report

It may be noted that the staff's results are comparable to those obtained by Ralph M. Rotty, A. M. Perry, and David B. Reister in their report *Net Energy from Nuclear Power*, IEA-75-3 (Institute for Energy Analysis, Oak Ridge, Tennessee, November 1975). Their report (Table 1.1) shows that the lifetime energy requirement to produce 1970 trillion Btu from a 1000-MWe pressurized water reactor is about 101 trillion Btu. This assumes 30 years of operation, a capacity factor of 75%, a heat rate of 10,000 Btu/kWhr, fuel from conventional (current) uranium ores, enrichment tails of 0.30%, and plutonium recycle.

Thus, on the basis of the IEA analysis, the thermal energy required to build and operate the nuclear power plant equals only about 5% of the thermal energy output of the plant. This may be compared with 6% in the staff analysis of the similar case previously discussed; or in other terms, the IEA analysis results in the amount of thermal energy produced being approximately 19.5 times the thermal energy expended, a favorable comparison with the staff's result of a factor of about 19.

Also of significance is the analysis of net energy yield by IEA involving the use of lower concentration ores (Chattanooga shales). These ores of lower concentration require larger energy inputs in mining and milling, and in the case of the Chattanooga shales, these energy requirements are the dominant ones. Even so, the IEA calculations lead to an estimate of about 288 trillion Btu expended, or about 15% of the 1970 trillion Btu energy production.

The following summary also includes cases of no plutonium recycle and a case where a different enrichment of tails is assumed.

| System (all 1000-MWe PWR's | Energy (trillions of Btu) |
|---|---|
| **Energy Required** | |
| No recycle conventional ores, 0.30% enrichment tails | 133 |
| No recycle, conventional ores, 0.20% enrichment tails | 152 |
| Pu recycle, conventional ores, 0.30% enrichment tails | 101 |
| No recycle, Chattanooga shales, 0.30% enrichment tails | 288 |
| Pu recycle, Chattanooga shales, 0.30% enrichment tails | 201 |
| **Energy Produced** | |
| 30 years, 75% plant factor, heat rate of 10,000 Btu/kWhr | 1970 |

The IEA report also includes cases for different types of reactors. The energy inputs given for boiling water reactors and high-temperature gas-cooled reactors are comparable with those for pressurized water reactors, while the inputs for heavy-water reactors are substantially less.

The IEA report considers various ratios between energy outputs and inputs. In some of these, electrical energy is directly added to thermal energy or divided by thermal energy without converting from one to the other by means of the thermodynamic efficiency. This has been avoided in the staff analysis.

It should be pointed out, in conclusion, the the IEA report is perhaps the most comprehensive current work on net energy from nuclear power published to date.

10.3.6.7 Comparison with Fossil-Fueled Electric Plants

The net energy study "The Total Energy Investment in Nuclear Power Plants" by Charles T. Rombough and Billy V. Koen and published as Technical Report ESL-31, Energy Systems Laboratory, College of

Engineering, University of Texas, November 1974, and also summarized in Nuclear Technology (May 1975), concluded that for a 1000-MWe nuclear plant (using a pressurized light-water reactor) operating over a 30-year lifetime at an 80% load factor, the total investment in energy is approximately 7.1% of the output. Using the same major parameters of 1000 MWe, 30-year life, and an 80% load factor for comparison purposes, the total energy requirement for construction of a coal-fired power plant is about 7.8% for deep-mined coal and 6.7% for surface-mined coal. On a total system energy cost, this study shows a comparability between nuclear plants and coal plants.

The staff agrees with the views of Dr. Cashman that net energy analysis should be further developed and used as a planning tool to provide additional information to supplement economic, technical, and environmental information. The staff intends to continue directing an effort to the question of net energy balances; however, in this particular generic statement, the staff's discussion of solar and wind energy as an alternative to large base-load nuclear power plants does not justify net energy calculations in which the net energy from nuclear plants is compared with that of direct use of wind and solar generators.

## 10.4 BENEFIT-COST BALANCE

### 10.4.1 Benefit Description of the Proposed Facility

#### 10.4.1.1 Expected Annual-Average Generation

The staff expects the BFS to operate at a capacity factor of between 50% and 70% and thus generate between 10,074,000 MW-hr and 14,103,600 MW-hr each year.

#### 10.4.1.2 Proportional Distribution of Electrical Energy

PSO expects the distribution of its sales to be: residential--22%, commercial--17%, industrial--20%, and other--41%. Associated expects the distribution of its sales to be: residential--81%, commercial--15%, industrial--2%, and other--2%.

#### 10.4.1.3 Taxes

As mentioned in Section 4.4.3, the increase in the taxes collected by the Inola School District due to BFS can be judged a benefit to that district. However, these taxes are ultimately paid for by other of PSO's customers and thus must be judged a cost to them. The staff has therefore counted this redistribution of income via taxes as neither a benefit nor cost in its evaluation of Black Fox Station.

#### 10.4.1.4 Employment

Approximately 136 operating and maintenance personnel with an aggregate annual income of $3,095,000 (1985 dollars) will be employed at the station.

#### 10.4.1.5 Regional Development

The applicant implicitly assumes a certain level of future economic development in the service area. Availability of the capacity and energy output of the proposed units would contribute to making possible this level of development, but would not automatically induce it.

### 10.4.2 Cost Description of the Proposed Facility

#### 10.4.2.1 Economic Costs

Estimated economic costs of the BFS are given in Table 10.12.

Table 10.12. Economic Costs of Construction and Operation of Black Fox Station Units 1 and 2 (in millions of 1984 dollars except as noted)

| Basis | Construction and Decommissioning | Operation | Fuel[b] | Total |
|---|---|---|---|---|
| Present value[a] | 1700 | 311 | n.a. | n.a. |
| Annualized | 180 | 30 | 104 | 314 |
| Mills/kWh at capacity factor 0.6 | 14.0 | 2.4 | 8.1 | 24.5 |

[a]At midpoint (July 1984) between scheduled commercial operation dates for first and second units.

[b]Based on staff estimates of 1976 costs and eight years of escalation at an assumed annual rate of 5%. The 1976 estimated cost for Wyoming coal delivered to the Tulsa area is 12.6 mills/kWh.

10.4.2.2 Environmental Costs

The environmental costs expected from construction and operation of the station are summarized in Table 10.13.

10.4.2.3 Environmental Costs of the Fuel Cycle

The environmental costs associated with the uranium fuel cycle are summarized in Table 5.6. Their contribution to the overall environmental costs is small enough that the conclusion of the benefit-cost balance is not significantly affected.

10.4.2.4 Environmental Costs of Transportation

The environmental effects of transportation of fuel and waste to and from the facility are summarized in Section 5.4. The impact of those effects is sufficiently small so as not to affect significantly the conclusions of the benefit-cost balance.

10.4.3 Benefit-Cost Balance

The primary benefit from the operation and construction of the proposed station will be the production of about 12 million MW-hr per year over the life of the station. The construction and operation of the BFS will also create a substantial amount of economic activity with associated increased employment and commerce.

The major environmental impacts to be expected from the construction and operation of the proposed units appear to be those typically associated with the creation of large new industrial plants in rural areas. An average of 1150 people will be employed on the site during the seven-year construction period. The circular mechanical-draft cooling towers will issue visible plumes that will be seen most frequently during the winter.

About 2206 acres will be diverted from other uses, such as cattle production, to an industrial complex. Although many other environmental impacts are assessed in Sections 4 and 5 and are listed in Table 10.13, none appears to be more than barely perceptible against the normal fluctuations of the environment.

The primary benefit of increased availability of electrical energy in the applicant's service area and in the SPP region will outweigh the environmental and economic costs of the station.

The staff concludes that the overall environmental impact resulting from the construction and operation of the BFS as proposed will be the minimum practicable for a 2300-MWe nuclear electrical generating facility if the conditions enumerated in the Summary and Conclusions are implemented. Further, the overall benefit-cost balance would not be significantly improved by an alternative choice of site or by the use of an alternative generation system.

Table 10.13. Summary of Environmental Effects due to Construction and Operation of the Black Fox Station Units 1 and 2

| Effect | Reference Section | Impact |
|---|---|---|
| Land | | |
| Diversion of about 2206 acres to industrial use | 4.1, 5.1 | Negligible to positive |
| Loss or alteration of 530 acres of natural habitat | 4.1, 4.3 | Small to severe |
| Water | | |
| Consumptive loss of about 3% of the normal regulated flow (15% of the regulated minimum flow) of the Verdigris River | 5.2 | Negligible |
| Increased local temperature of Verdigris River water (less than 580 $ft.^2$ increased 5°F) | 5.3 | Negligible |
| Loss of river plankton (< 15%) by entrainment | 5.3 | Minor |
| Temporary increase of siltation in the Verdigris River | 4.2, 4.3 | Negligible |
| Temporary loss of benthic habitat (< 0.1 acre) | 5.3 | Negligible |
| Air | | |
| Occasional visible plume aloft from CMDCTs | 5.3 | Negligible |
| Ground-level fogging and icing (mostly onsite) | 5.3 | Minor |
| Deposition of drift (essentially all onsite) | 5.3 | Negligible to minor |
| Visual | | |
| Occasional visible plume aloft from CMDCTs | 5.3 | Negligible |
| Facility structures visible from certain areas | 5.3 | Negligible |
| Transmission lines and towers | 5.1 | Minor |
| Radioactive Effluents | | |
| Public radiation exposure (71 man-rem/yr) | 5.4 | Negligible |
| Workers' radiation exposure (1000 man-rem/yr) | 5.4 | Minor |
| Radiation exposure to construction workers (84 man-rem/yr) | 4.1 | Minor |
| Social and Economic | | |
| Disturbance of archeological sites | 4.1 | Small |
| Increased traffic congestion | 4.4 | Minor |
| Increased stress on housing market | 4.4 | Small to moderate |
| Increased stress on classroom facilities | 4.4 | Moderate |
| Increased stress on social services | 4.4 | Moderate |
| Payroll | 4.4, 5.9 | Beneficial |
| Induced expenditures | 4.4, 5.9 | Beneficial |
| Local taxes | 5.9 | Beneficial |

References


1. U. S. Atomic Energy Commission, Rules and Regulations--Title 10--Atomic Energy--Part 50--"Licensing of Production and Utilization Facilities," §50-51, "Duration of license, renewal."

2. Ibid., §50-82, "Applications for Termination of Licenses."

3. Ibid., §50-33, "Contents of Applications; General Information."

4. Atomic Energy Clearing House, Congressional Information Bureau, Inc., Washington, D. C., Vol. 17, No. , p. 42; Vol. 17, No. 10, p. 4; Vol. 17, No. 18, p. 7; Vol. 16, No. 35, p. 12.

5. "Supplement No. 2 to the Environmental Report, Units 1 and 2, Diablo Canyon Site," Pacific Gas and Electric Company, July 28, 1972.

6. "Uranium Industry Seminar," USAEC, Grand Junction, Colorado Office, GJO-108(74), October 1974.

7. "Survey of U. S. Uranium Marketing Activity," ERDA 76-46, April 1976.

8. "Survey of U. S. Uranium Marketing Activity," USAEC, WASH-1196(74), April 1974.

9. USAEC Press Release No. T-517, October 25, 1974.

## 11. DISCUSSION OF COMMENTS RECEIVED ON THE DRAFT ENVIRONMENTAL STATEMENT

Pursuant to 10 CFR Part 51.25 the Draft Environmental Statement for the Black Fox Nuclear Generating Station, Units 1 and 2, was transmitted with a request for comments to:

- Advisory Council on Historic Preservation
- Department of Agriculture
- Department of the Army, Corps of Engineers
- Department of Commerce
- Department of Health, Education and Welfare
- Department of Housing and Urban Development
- Department of the Interior
- Department of Transportation
- Energy Research and Development Administration
- Environmental Protection Agency
- Federal Power Commission
- Federal Energy Administration
- Office of the Governor of Oklahoma
- Mayor of Inola

In addition, the NRC requested comments on the Draft Environmental Statement from interested persons by a notice published in the Federal Register. Comments in response to the requests referred to above were received within the 45 day comment period from:

- Advisory Council on Historic Preservation (ACHP)
- Department of Agriculture, Agricultural Research Service (DOA Agr. Research)
- Department of Agriculture, Soil Conservation Service (DOA, Soil. Cons.)
- Department of Agriculture, Economic Research Service (DOA, Econ. Research)
- Department of the Army, Corps of Engineers (CE)
- Department of Commerce (DOC)
- Department of Health, Education and Welfare (HEW)
- Department of the Interior (DOI)
- Department of Transportation (DOT)
- Energy Research and Development Administration (ERDA)
- Environmental Protection Agency (EPA)
- Oklahoma State Department of Health (OSDOH)
- Public Service Company of Oklahoma (PSO)
- Sierra Club (SC)
- Carrie Dickerson, Citizens' Action for Safe Energy, Inc. (CASE)
- Cathy Coulson Currin, Citizens' Action for Safe Energy, Inc. (CASE)
- Joyce Nipper (NIPPER)
- Roberta Ann Funnell (FUNNELL)
- Mike A. Males (MALES)
- Stephen G. Schmelling (SCHMELLING)
- Ilene Younghein (YOUNGHEIN)

The staff consideration of comments received and the disposition of the issues involved are reflected in part by text revisions in other sections of the Final Environmental Statement (FES) and in part by the following discussion which will reference the comments by use of the abbreviations indicated above. The reference includes the abbreviation of the commentor and the page in Appendix A where the comment appears. As noted previously, all comments received are included in Appendix A of this statement.

### 11.1 RESPONSES TO COMMENTS BY FEDERAL AND STATE AGENCIES, APPLICANT AND OTHER INTERESTED PARTIES

#### 11.1.1 Summary and Conclusions

##### 11.1.1.1 Likelihood of Discovery of Archeological Resources (PSO-A79)

Archeological resources have been reported on the proposed plant site and are known from other areas in this general sector of Oklahoma. The presence of these sites was determined by

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intensive survey methods and the transmission corridors must be examined for the presence or absence of prehistoric and historic remains. The location of archeological sites cannot be determined "a priori" and without field surveys. This is because the environmental conditions of the past and suitability for prehistoric and early historic exploration frequently cannot be determined on the basis of present conditions.

11.1.1.2 Classification of Cropland and Pastureland (DOI-A106)

The 170 acres is part of the 460 acres of cropland and part of the 2400 acres of pastureland. No attempt was made to distinguish between crop and livestock production here because future agricultural practices may change.

11.1.2 <u>The Site and Environs</u>

11.1.2.1 Water Provided by Contract (SC-A71)

Details of the water supply contract between the City of Tulsa and PSO are not known at this time since the agreement has not been reached. The staff will require assurance that a reliable water supply is available prior to licensing the plant.

11.1.2.2 Bird Creek Water Quality (SC-A71)

The responsibility for assuring that present or future effluent discharged from the Tulsa treatment facility into Bird Creek meet the EPA effluent guidelines rests now, and will rest in the future, with the City of Tulsa and is independent of BFS operation. Subsequent use of this water by BFS after it enters Verdigris River, if any, will have no deleterious bearing upon water quality of Bird Creek.

11.1.2.3 Freedom of Information Act Request (SC-A71)

This request was responded to by letter from the NRC dated October 1, 1976. The following information was provided:

> The spokesman's name is Mr. Richard Kimberling of the City of Tulsa Sewer and Water Department.

11.1.2.4 Term of Water Contract (SC-A71)

See response 11.1.2.1.

11.1.2.5 Water Availability for City of Tulsa (SC-A71) (YOUNGHEIN-A46)

The staff has discussed the issue of water availability and water use in the revised Section 2.3 and 5.2 of this FES.

11.1.2.6 Water Use Based On "Worst Drought of Record" (SC-A71)

The Corps of Engineers has estimated the worst drought of record as occurring approximately once in 50 years. Therefore, the worst drought of record is synonymous with the 50-year drought in this case. It should be noted that the applicant actually designed for a water supply approximating a 100-year drought.

11.1.2.7 Proximity to Population Centers (SC-A72, YOUNGHEIN-A44)

The NRC staff recognizes the safety significance of this issue which is being considered in the safety review. Since the safety review is not complete at this time, it would be inappropriate to respond to this comment. The conclusions of the staff's safety review will be reported and made public in the NRC Safety Evaluation Report.

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11.1.2.8 Fish and Wildlife Management (DOI-A104)

The staff agrees with the DOI that the BFS site offers a good opportunity for wildlife enhancement and management. In particular, the staff believes that the exclusion of livestock from the grasslands on site presents an excellent opportunity for the enhancement and protection of prairie and forest border wildlife. During the site visit, the staff considered the feasibility of wildlife enhancement programs in informal discussions with the applicant's consultants and in staff observations. The staff concluded from the site visit and subsequent analysis that such programs were feasible and desirable, but could not resolve satisfactorily the issue of whether or not the attendant economic cost was a reasonable constraint to be imposed on the applicant. Based on the staff analysis, the onsite terrestrial habitats will improve by natural succession (Sect. 4.2.1.1, p. 4-9; Sect. 5.6.1.2, p. 5-29 to 5-30), and presumedly any suitable wildlife species which can immigrate will become established, thereby enhancing the local and regional wildlife, without imposing additional economic cost on the applicant.

For the most part, the transmission corridors cannot be managed for wildlife by the applicant. Along the transmission corridors the applicant will be granted only a right-of-way easement by most of the landowners involved.

11.1.2.9 Streamflow Characteristics (DOI-A104)

See response 11.1.2.5.

11.1.2.10 Availability of Water for Plant (SCHMELLING-A69)

See response 11.1.2.5.

11.1.2.11 Increased Cloud Cover (CASE-A73)

The nature of the low height MDCT's precludes the type of moisture plumes associated with tall hyperbolic natural draft cooling towers. Any fogging or misting resulting is expected to remain within the plant boundaries. Ongoing studies of all types of cooling towers under varying operating conditions are being conducted to identify long-term climatic impacts of cooling towers, although at the present time it is not expected that any cause and effect relation will be found between the two.

Any decrease of sunshine resulting from ground level fogging should be insufficient to alter farming or living patterns in the plant vicinity. There will be no effect of the onsite plume on crops because the proposed onsite land uses for the life of the plant preclude the used site for crop production. For other flora, no adverse impact is expected.

11.1.2.12 Seismic Activity in Area (CASE-A75)

The discussion of seismicity and tornadoes in the DES was intended to be brief and descriptive. The full and detailed analysis of seismicity, earthquake hazards and tornadoes will be discussed in depth as part of the safety review in the staff's Safety Evaluation Report.

11.1.2.13 Tornadoes (CASE-A75)

See response 11.1.2.12.

11.1.2.14 Problems Due to Red Clay Soil (YOUNGHEIN-A46)

As noted in Section 2.4.3 of the DES, the soils in the site area are not red clays. Red clays are not as common to northeastern Oklahoma as they are to central Oklahoma. The ability of the soils to accept moisture has been considered in the safety evaluation of the plant and because the soils on the site are composed of dark clays and silty clays, minimum infiltration rates were used in estimating flood potential.

The staff's environmental analysis leads to the conclusion that "extreme runoff" will occur at least annually (the one-year period runoff will generate flows of 500 cfs, p. 4-1).

The staff analysis further determined that the soils at the central complex site have "low to moderate shrink-swell potential," and so should not pose any threat to the structural integrity to the BFS structures.

### 11.1.3 The Station

#### 11.1.3.1 Radioactive Liquid Waste Releases (PSC-A80) (DOI-A106)

Since the radioactive liquid waste system does not have sufficient tank capacity to collect and hold wastes during an assumed 2 day/week process equipment outage, an alternate path was assumed for the waste consistent with Section 2.2.20.2 of NUREG-0016. The assumption of 0.15 Ci/yr/reactor for unplanned releases is consistent, therefore, with the parameters and models used by the staff to calculate the releases of radioactive materials in liquid effluents from BWR's.

The applicant used the General Electric Company's Topical Report NEDO-21159 as a basis for his source term calculations. The GE Topical Report was found unacceptable by the staff under the Topical Report Review Program and therefore it is not an acceptable reference at this time.

#### 11.1.3.2 Road Construction (DOI-A106)

The requested explanation can be found in the discussion of the impacts of the construction of the transmission lines (first two paragraphs of Section 4.1.3, pp. 4-6 to 4-7), including the staff's recommended "road removal" plan.

#### 11.1.3.3 Onsite Storage of High Level Wastes (SCHMELLING-A69) (YOUNGHEIN-A45)

Every nuclear power plant in the United States temporarily stores spent fuel elements in spent fuel pools. The staff's assessment of the radiological impact of Black Fox Station as described in Section 5.4 of the environmental statement includes the impact of onsite storage of spent fuel.

The solids radwaste system evaluated in Section 3.5.2 of the DES is concerned with the handling of radioactive solid waste to be packaged for offsite disposal. High-level radioactive wastes, such as those produced at fuel reprocessing plants, are not part of the solid radwaste system evaluation. There will be no long-term storage of radioactive waste at Black Fox Station.

#### 11.1.3.4 Radioactive Waste Treatment (EPA-A101)

The proposed design of the Black Fox Station uses clean steam at the gland seals but does not utilize clean steam to seal valves. The staff has evaluated the proposed design in the DES. The staff concluded that the liquid and gaseous radwaste treatment systems will reduce radioactive materials in effluents to "as low as is reasonably achievable" levels in accordance with 10 CFR Part 50.34a and, therefore, are acceptable.

#### 11.1.3.5 Loss of Cooling Water and Other Unresolved Safety Problems (YOUNGHEIN-A46, A48)

The NRC staff recognizes the safety significance of this issue which is being considered in the safety review. Since the safety review is not complete at this time, it would be inappropriate to respond to this comment. The conclusions of the staff's review will be reported and made public in the NRC Safety Evaluation Report.

#### 11.1.3.6 Impact of Transmission Facilities Upon Illinois River (SC-A72)

The text (p. 3-32) has been modified to include the possibility of the Illinois River and its environs being designated a Wild and Scenic River.

### 11.1.4 Environmental Impacts of Construction

#### 11.1.4.1 Discharge Channel (DOI-A106)

The discharge channel is discussed in Section 4.1.2.2 and the railroad spur and access roads are discussed in Section 4.1.2.3 of this FES. The acreages to be disturbed, while not shown explicitly as a line item, are already included in Table 4.1. These were not listed explicitly in order to simplify the table, including as specific items only the major sources of disturbance.

#### 11.1.4.2 Staff recommendations (DOI-A106)

A comment was made that the staff should be more specific rather than "recommending" or "suggesting." The staff uses the terms "recommends" or "suggests" in cases where a perceived impact is not considered severe enough to warrant the requirement of a preventive or mitigating action, but where it believes that some beneficial effect could be realized if the applicant would elect to carry out a staff recommendation or suggestion. In circumstances where the staff believes that there will be environmental impacts of consequence if mitigating or alternate actions are not taken, the ASLB is asked to impose specific requirements. In such cases, terms such as "will require," or "shall" are used in the Environmental Statement.

#### 11.1.4.3 Potentials for Erosion (PSO-A81)

The staff analysis is based on the most conservative runoff event possible (the one year return period runoff event). The probability that this runoff event will be exceeded during the construction permit stage for BFS is high, yet the conservative runoff will generate-flows of 500 cfs. The staff cannot believe that any soil of which 80% will pass through a number 200 sieve can withstand flows of 500 cfs without eroding. Again, the staff requirement is conservative, requiring that specific attention be directed to controlling only gully erosion. The staff also believes that sheet erosion could be a problem in this draw. There is no evidence of PSO committing to control this erosion which appears virtually certain to occur. Staff's position regarding the requirement is unchanged.

#### 11.1.4.4 Holding Pond Elevation (PSO-A81)

The initial pond elevation is given as 553 feet MSL (ER, Suppl. 0, Answer 3.8); the ultimate pond elevation is 558 feet MSL.

#### 11.1.4.5 Archeological Sites (PSO-A81)

The applicant has quoted the provisions of part 800.10 correctly. In addition, the State Historic Preservation Office has reviewed the project and expressed no concern since the properties are out of the project area. Section 4.1.1.4 has been changed accordingly.

#### 11.1.4.6 Possible Oil Leakage (PSO-A81)

The staff has reiterated PSO's apparent concern for potential inadvertent impacts of oil leakage not directly attributable to PSO.

#### 11.1.4.7 Monitoring of Runoff from Spoils--Deposit Areas (PSO-A82)

The staff believes that runoff from the spoil deposit area, if not properly contained, could cause deleterious impacts to the aquatic system of the Verdigris River. A monitoring program would be a necessity to insure that spoils are being properly contained. The staff therefore believes that Paragraph 7, Section 4.3.2.2 should stand as is.

#### 11.1.4.8 Necessity for Qualified Biologist (PSO-A82)

The staff believes that inspection by a qualified biologist of habitat that has been designated as unique (Section 3.7.3) is reasonable and necessary.

11.1.4.9 Grass Planting in Specific Areas (PSO-A82)

The staff recommendations have been reworded to reflect the possibility that other planting methods may be suitable.

11.1.4.10 Impact of Construction Workers on Outdoor Recreation (DOI-A105)

It was recommended in a comment that the applicant establish a program to address the impact that large numbers of construction workers will have on recreation in the communities in the BFS area.

The staff concurs with this suggestion. Section 4.4.4 has been appropriately changed.

11.1.4.11 Urban Outmigration (SCHMELLING-A69)

A study* reported that in 1972 about 64 percent of employed people in the Inola area were working in other communities, mainly in the Tulsa area. The current trend of out-migration from Tulsa metropolitan region to eastern towns will be continued and the population in the cities of Inola, Claremore, Waggoner, and southern Washington and Mayes Counites will likely be expanded in consequence.

In addition to the operation of the Black Fox Station, manufacturing companies reportedly committed to construct in this area should, when completed, employ approximately 1300 persons.** The regional planning agencies anticipated over 400 percent population increase in the Inola area during the year 1970 to 2000.*,** Particularly, the scheduled completion of state highway 33 would contribute significantly to the residential development in this area.

The revenue generated by the Black Fox Station construction will provide the fund to finance the necessary expansion and improvement of community service at relatively low cost to the residents, particularly for the school district. However, the delineation of the net impact of the anticipated growth in the Inola area attributable to the Black Fox Station, in terms of its duration and magnitude, would be merely speculative at this point.

11.1.5 Environmental Impacts of Plant Operations

11.1.5.1 Impact of Effluents on Red Bud Valley (SC-A71)

The City of Tulsa is responsible for assuring that the sewage effluent entering Bird Creek from its treatment facility meets applicable waste quality standards. Subsequent use of this water after it enters Verdigris River by BFS, if any, would have no affect on Bird Creek or Red Bud Valley.

11.1.5.2 Impact on Tulsa Citizens of Increasing Water Costs (SC-A71)

The suggestion that the citizens of Tulsa would be subject to increasing water costs if BFS would e[illegible] use Tulsa's sewage effluent is incorrect. On the contrary, the only monetary impact would be that revenue would be received by the city from the sale of sewage effluent if such source was ever used by BFS.

11.1.5.3 Nuclear Fuel Cycle Costs and Impact (SC-A72)

This issue is discussed in the revised Section 5.8 of this FES.

11.1.5.4 Implications of Federal Water Pollution Control Act (SC-A72)

The DES has been reviewed by the Environmental Protection Agency (EPA) and EPA comments are included in Appendix A (page A-99). The staff finds no indication in those comments of EPA's concerns in this area.

11.1.5.5 Effects on Drinking Water Supply Downstream (SC-A72)

Section 5.4 evaluates the potential radiological impact of the liquid effluents of Black Fox Station. The doses which would be received by persons drinking water from the Verdigris River

*Telephone communication with Mr. M. Z. Williams, Director, Claremore Regional Planning Commission, Claremore, Oklahoma (1/20/77).

**"Community Development Plan, Inola, Oklahoma," Northeast Counties of Oklahoma Economic Development Association, 1974.

downstream of the plant were estimated. Also, the potential impact of these doses is presented in terms of comparisons with the doses received from natural background radioactivity.

11.1.5.6 Radioactive Wastes (DOI-A105)

The solid radwaste system evaluated in Section 3.5.2 is concerned with the handling of radioactive solid waste to be packaged for offsite disposal and the quantities and types of anticipated solid radioactive waste are provided. High-level radioactive wastes, such as those produced at fuel reprocessing plants, are not part of the solid radwaste system evaluation.

As discussed in Section 11.1.5.3 above, the newly promulgated Interim Proposed Rule (NUREG-0116) and forthcoming final interim rule are designed to adequately supplement Table S-3 in regard to waste management and reprocessing. To that extent, future environmental assessments should be adequate.

11.1.5.7 Mineral Resources (DOI-A105)

The comment was made that oil and gas production at the BFS site should be allowed to continue The staff is of the opinion that the potential for accidents resulting in fire and/or explosion that will accompany this limited production far outweigh the benefits of its continuation during the plant operating lifetime.

11.1.5.8 Extent of Thermal Plume (DOI-A107)

The staff has calculated the extent of the thermal plume under the conservative conditions of an ambient river velocity of 0.045 fps which corresponds to a riverflow of 379 cfs. The important parameter in the plume calculations is not the river velocity but the ratio of the river velocity to the blowdown discharge velocity (.007 fps). At such a low ratio, the difference between the calculated plume and one for the stagnant case (zero flow) is much smaller than the accuracy of the model used.

11.1.5.9 Fish and Wildlife Management Plan (DOI-A107)

The staff agrees that a "plan and proposed implementation schedule" is desirable and necessary if the applicant's conclusion that "there will be a beneficial commitment of the site..." to native communities and wildlife habitats is to be realized. The intent of staff's formal question numbers 4.5, 4.6, 4.7 and 5.19 (ER, Suppl. 0) was to elicit a commitment from the applicant to develop a plan for the utilization of the site potential for effective wildlife management programs. However, since the staff concluded from their analysis that the proposed BFS site development does not pose any realistic threat to the existing local wildlife populations (Section 4.3.1.2, p. 4-9), and does afford potential benefits to wildlife without intensive management (Section 5.6.1.2, p. 5-31), the imposition of the economic costs of wildlife management as a staff requirement does not appear warranted. An example of specific staff recommendations to insure the successful establishment of native communities on the BFS site can be found in the last paragraph of Section 4.3.1.1 (p. 4-9).

11.1.5.10 Commitment to Different Ecosystem (DOI-A107)

The commenter suggested that a more thorough explanation be given for the term "productive" as used in the discussion of a different ecosystem.

The applicant concluded that "the commitment of the site to a different ecosystem" would be "more productive." Nowhere did the staff agree with the designation of the different ecosystem as "more productive," nor can the staff provide a definition of the applicant's intended meaning of the term "productive" in this context. The staff concluded (p. 5-31) that the "different ecosystem" in this case could "result in improved wildlife habitat." The staff is fully aware that this is not synonymous with any direct benefit to wildlife, since there is no mechanism discussed anywhere in the Environmental Statement which will guarantee the actual utilization of this habitat by wildlife.

11.1.5.11 Loss of Entrained Plankton (DOI-A107)

The staff believes that adequate discussion has been provided to support the claim that ichthyoplankton losses will be nondetrimental, even during low flow conditions. Supportive references on preferred spawning sites and fecundity values for the fish species present in the Verdigris

River (DES Tables E.1 and E.2) coupled with the low numbers of fish eggs collected by the applicant in the area of the proposed intake substantiated the view that ichthyoplankton losses will be minimal.

If the applicant's monitoring program does reveal entrainment losses greater than expected, due to the uncertainty over actual fish distribution patterns that may occur, mitigating measures will be taken at that time to match the type(s) of organisms entrained, e.g., a different type of mitigating action will be recommended for entrainment of game fish larvae in comparison to "rough" fish larvae. As it is not possible to forecast the exact nature of deleterious entrainment losses, if any, amendments to the Technical Specifications (which will be issued at the operating license review stage) will be made to correct entrainment losses based upon results of the applicant's monitoring program.

As discussed in Sec 5.6.2.1, losses generally are not expected to be significant. Losses occurring during low flow periods, unless such periods extend over a long period of time, should be more than compensated for due to the high reproductive potential of the Verdigris River biota. Any mitigating actions to be taken, if monitoring indicates entrainment losses to be significant, however, cannot be made at this time, but rather would have to be made at a later date based upon monitoring data.

11.1.5.12 Population Dose Commitments for Carbon-14, Krypton-85, and Tritium (ERDA-A95)

Appendix C of the environmental statement describes the methodology used by the staff in making population dose assessments for carbon-14, krypton-85, and tritium. Those models evaluate the population exposure at the mid-point of plant life, rather than an integration over the full atmospheric and ocean lives of these nuclides. The staff feels that this assessment as presented in the environmental statement is sufficient.

11.1.5.13 Onsite Storage of High-Level Wastes (SCHMELLING-A69)

This issue has been discussed in Section 11.1.3.3.

11.1.5.14 Effects of Radiation on Aging (YOUNGHEIN-A64)

A paper entitled, "Health Effects of Low-Level Radiation," by Dr. Rosalie Bartell was submitted for comment.

The evidence* on life shortening due to radiation exposure does not support Dr. Bertell's claims in her paper, "Health Effects of Low-Level Radiation." The staff feels that the life shortening effects have been properly evaluated in the environmental statement.

11.1.5.15 Risk to Humans from Radiation (FUNNELL-A97)

The comment was made that "any radiation is too much."

The staff currently advocates and uses the linear non-threshold theory of damage and risk to humans from radiation. There is a certain amount of biological damage and risk associated with any amount of radiation, no matter how small. However, the staff does not agree that "any radiation is too much." Physicians judge when the amount of risk caused by diagnostic and therapeutic radiation is large enough to offset the benefit which will be received from the diagnosis or treatment. In assessing the radiological impact of a nuclear power plant, the staff makes a similar risk versus benefit judgment. As explained in Section 5.4 of the environmental statement, the doses which people living near Black Fox Station might receive are very small, much smaller than doses from natural background radiation. Thus, it is the staff's judgment that the very small biological risks from these low doses do not offset the benefits of adequate electrical power.

11.1.5.16 Offsite Sampling (OSDOH-A98)

The commenter suggested that additional offsite sampling locations should be established.

For the purposes of routine operational radiological environmental monitoring, no additional airborne particulate or airborne iodine sampling locations are necessary. The Black Fox Station program as presented in Section 6.1 of the environmental statement meets or exceeds the recommendations of Regulatory Guide 4.8, Environmental Technical Specifications for Nuclear Power Plants.

*The Effects on Populations of Exposure to Low-Levels of Ionizing Radiation. Report of the Advisory Committee on the Biological Effects of Ionizing Radiation. National Academy of Sciences--National Research Council, Washington, D.C., November 1972.

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11.1.5.17 Frequency of Soil Sampling (OSDOH-A98)

Commenter suggested that soil sampling be done more often. The purpose of soil sampling is to monitor what is expected to be a very slow build-up of long-lived radionuclides such as cesium-137. For that reason, Regulatory Guide 4.8, Environment Technical Specifications for Nuclear Power Plants, recommends soil sampling every three years. Thus, more frequent soil sampling by Black Fox Station is not necessary.

11.1.5.18 Monitoring Systems for Liquid and Gaseous Effluents (OSDOH-A98)

A comment was made that the monitoring systems should be described in more detail.

The monitoring systems are evaluated and described to the extent necessary to show that the plant effluents will meet guidelines and regulations. The detailed description and evaluation of the monitoring systems will be provided in the Safety Evaluation Report.

11.1.5.19 Dose Assessment (OSDOH-A98)

The discrepancy in Table 5.9 of the draft statement has been corrected.

11.1.5.20 Dispersion Parameters Used in Dose Calculations (EPA-A101)

As indicated in Section 6.1.4 of the environmental statement, the gaseous dispersion and deposition used in the calculation of doses were based on:

1. the applicant's onsite meteorological data, and

2. the calculational methods of Regulatory Guide 1.111.

11.1.5.21 Releases from Turbine Building Ventilation Exhaust (EPA-A101)

Section 2.7.2.1 describes the site as it is before construction. There will be no cattle grazing onsite after BFS goes into operation. As indicated in Table 5.6 of the statement, the "Nearest" location means the location at which the highest dose is expected from appropriate pathways. In accordance with 10 CFR Part 50, Appendix I, the staff's dose estimates for comparison with Appendix I design objectives are calculated such that doses are not "substantially underestimated." Thus, the staff does not feel that the turbine building ventilation treatment options should be reexamined.

11.1.5.22 EPA's Drinking Water Regulations for Radionuclides (EPA-A101)

EPA's Drinking Water Regulations are scheduled to become effective on June 24, 1977. A comment was made that the FES should include references to these regulations.

The staff's methods of implementing EPA's Drinking Water Regulations for Radionuclides have not been formalized. The adherence of Black Fox Station to those regulations will be explained in the environmental statement prepared by the staff during the environmental review at the operating license stage.

11.1.5.23 Population Dose Commitments (EPA-A102)

The population dose assessments presented in the environmental statement consider: 1) the estimated U.S. population at midpoint of plant life, 2) 50-year dose commitments, and 3) the build-up of radionuclides in the environment to the midpoint of plant life.

The staff does not feel that dose commitments out to 100 years are appropriate or provide significant additional information. NUREG-0002, Final Generic Environmental Statement on the Use of Recycle Plutonium in Mixed Oxide Fuel in Light-Water Cooled Reactors, presents a generic assessment of the world population dose from light-water reactors.

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11.1.5.24 EPA's Proposed Uranium Fuel Cycle Standards (EPA-A102)

A comment was made that the FES should address direct radiation dose in the context of EPA's proposed uranium fuel cycle standards.

The EPA standards on offsite doses from facilities in the uranium fuel cycle have not been published in final form and the NRC has therefore not finalized plans for implementation.

11.1.5.25 Drinking Water (CASE-A73, A74)

The doses which people living in the vicinity of Black Fox Station might receive have been estimated and presented in Section 5.4 of the environmental statement. All significant pathways by which people may be exposed to the radioactivity from Black Flox Station effluents have been included in these estimates. Regulatory Guide 1.109 explains how the staff estimates the transfer of radioactivity into man and the consequent dose to man.

For the liquid pathways, the dose estimates were based on the average annual river flow of the Verdigris River. During drought conditions, higher concentrations of radioactivity might be expected in the river water; however, on an annual average basis the dose estimates given in the environmental statement are not expected to be exceeded.

11.1.5.26 Increases in Temperature of River Water (CASE-A74)

The inhabitants of the area are being informed of the expected increase in temperature of the Verdigris River water and of its effects on river biota by means of Environmental Statments which are available in the public docket in the Tulsa City-County Library, Tulsa, Oklahoma.

Unplanned discharges of excessively heated water are not expected since a holding pond is provided for cooling of the blowdown water before discharge to the Verdigris River. Since the Black Fox Station utilizes cooling towers (not a once-through cooling system), increasing the water temperature is detrimental to plant operating efficiency, and is not expected to occur.

There are no NEPA or NRC water quality standards. The State Thermal Water Quality Standards are applicable to the Black Fox Station. These standards provide for a mixing zone, thus discharge temperature is not relevant except in the case when the national water temperature is in excess of 90°F.

Section 5.6.2.2 discusses the effects of increased water temperatures on the river biota. Worst case conditions were discussed and conclusions made that no detrimental impacts to biota will occur. See also Section 11.1.5.25.

11.1.5.27 Synergistic Effects (CASE-A74)

The staff is unaware of any synergistic effects that could occur between the Tulsa sewage discharge and the Black Fox discharge. Whatever residuals are present will be added but there is no reason to believe the effects will be amplified.

11.1.5.28 Timeliness of DES (CASE-A74)

A comment was made that insufficient time was provided for reviewing and commenting on the DES. The period of time provided for commenting on the DES is set by the guidelines of the Council on Environmental Quality. All interested parties wishing to comment on the DES (including various agencies of the Federal government), are to do so within the established period, therefore no organization was put to any particular disadvantage.

The ER, as well as the PSAR, DES, and other documents relevant to the licensing action have been available for public scrutiny from the time of docketing of the BFS application at the NRC Public Document Room, 1717 H Street, N.W., Washington, D.C., and at the Tulsa City-County Library, Tulsa, Oklahoma. It is the responsibility of interested parties to visit these public rooms to obtain any desired information.

11.1.5.29 Damage to the Environment Caused by Ozone (CASE-A75)

The staff analysis in Section 5.7 indicates that ozone production due to BFS transmission lines will be an order of magnitude less than EPA standards. No impact to the environment, and therefore no cost, is expected.

11.1.5.30 Environmental Impact of Fuel Cycle (CASE-A75)

This issue is discussed in the revised Section 5.8 of this FES.

11.1.5.31 Effects of Dispersion of Asbestos into the Atmosphere (CASE-A75, YOUNGHEIN-A49)

A comment was made that the staff has not considered the effects on human health of the dispersion of asbestos into the atmosphere from the cooling towers. The 6 round mechanical draft cooling towers proposed for the BFS are expected to contain asbestos cement fill bars, and drift eliminators made of neoprene asbestos material in a modified cellular form.[1] These asbestos-containing materials are subject to deterioration due to freeze-thaw cycles, chemical attack by acidic components in the circulating water, absorption of water, leaching of calcium, and (perhaps) microbial action. These materials are, however, fireproof compared to wood or plastic fill. The deterioration rate of the asbestos material is expected to vary with the climate and watet quality (site-specific factors) and with season at any given site; it is therefore not possible to accurately predict the erosion of asbestos particles from the tower materials into the circulating water, which eventually is discharged to the Verdigris River. The staff has made some rough calculations in this regard, and results are discussed below. First, however, it is necessary to understand the nature of the problem.

"Asbestos" is a general name for fibrous forms of amphibole and serpentine, natural rock-forming minerals. These consist of chrysotile (a fibrous form of serpentine) and amosite, crocidolite, tremolite, actinolite, and anthophyllite (fibrous forms of amphibole). These minerals are used extensively in the manufacture of brake linings, gaskets, floor tile, roof coatings, caulks, insulation, cement products, and a variety of other products. About 95% of the asbestos used in the U.S. is chrysotile, $3Mg \cdot 2SiO_2 \cdot 2H_2O$, most of which is mined in Canada.

Surface waters or ground water that flow through rocks containing asbestos minerals can be expected to contain some amount of asbestos fibers; certain industrial discharges, runoff from waste disposal sites and highways, and rain and snow likely add to the asbestos load of surface waters. It is conceivable, therefore, that the source of water to a given cooling tower may contain asbestos particles. In the case of the BFS cooling towers, no data is available regarding the asbestos content of the Verdigris River, as far as the staff has been able to determine. Based on the geology of the Verdigris River basin, however, the staff expects that the ambient concentration of asbestos in the river water will be less than $1 \times 10^6$ fibers per liter, if any are detected at all by state-of-the-art methods (limits of detection are on the order of $10^4$ to $10^5$ fibers per liter). High asbestiform mineral concentrations are more characteristic of igneous and metamorphic rocks, with the exception of Arizona-type asbestos which is found as thin serpentine layers in limestone.[2] Except for small intrusive bodies near the headwaters of the Verdigris in Kansas,[3] the river basin consists of sedimentary rocks, as far as the staff has been able to determine.[4]

In theory, the cooling towers at the BFS can contribute asbestos to the ambient environment in two ways: (i) to surface waters via blowdown, and (ii) to air via the cooling tower drift plume. The staff has estimated the possible magnitude of these contributions, based on the following assumptions:

a. Weight of the asbestos cement fill bars per tower is 506.8 metric tons.

b. Loss in weight of bars over lifetime of the tower is 50.7 tons/30 years.

c. Fill bars are 16% asbestos, the balance is portland cement.

d. Erosion rate of the fill is uniform over the life of the towers.

e. Asbestos particles eroded from the fill are homogenously mixed with the circulating water.

f. Circulating water for the 6 towers is $1.244 \times 10^6$ gal/min ($4.6 \times 10^6$ liters/min).

g. Concentration factor of cooling tower is 9.

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h. Blowdown to holding pond from the 6 towers is 3000 gal/min ($1.134 \times 10^4$ liters/min).

i. Asbestos concentration in the blowdown to the river is the same as the concentration in blowdown to the pond.

j. Blowdown to the river is 3000 gal/min ($1.134 \times 10^4$ liters/min).

k. Drift per tower is 10 gal/min (37.8 liters/min).

l. The 30-day average flow of the Verdigris is 279 cfs ($4.74 \times 10^5$ liters/min).

Results of the staff's calculations are as follows:

| | | |
|---|---|---|
| a. | Asbestos addition to the circulating water from the 6 towers | 3.0 gram/min |
| b. | Asbestos concentration in the circulating water | 0.64 ug/liter |
| c. | Asbestos concentration in blowdown to the river | 5.8 ug/liter |
| d. | Asbestos concentration in river water after mixing | 0.14 ug/liter |
| e. | Asbestos emission in drift per tower | 22.7 ug/min |
| f. | Asbestos emission in drift from the 6 towers | 136 ug/min |

There is presently no state or federal standard for asbestos in surface waters or public water supplies, nor have any effluent limitations been established. The chrysotile content of river water in the eastern United States has been reported to range from 0 to 23.5 ug/gal., with averages ranging from 1.3 to 5.9 ug/gal (0.34 to 1.56 ug/liter).[5] Amphibole asbestos in the municipal water supply at Duluth, Minnesota, was reported to range from 1 to 30 ug/liter, corresponding to about 1 to $30 \times 10^6$ fibers/liter.[6] Beverages sampled in Canada contained between 1.1 and $12.2 \times 10^6$ fibers per liter.[7] At 22 towns in Ontario, Canada, the asbestos fiber count in the distribution system water ranged from 0.384 to $3.87 \times 10^6$ fibers per liter. The Ministry of Health of Ontario has indicated that "ingestion of asbestos at these levels does not appear to present a health hazard at this time."[8]

As outlined above, the staff has estimated that the blowdown to the Verdigris River from the BFS may contain up to 5.8 ug asbestos per liter. After mixing with the river, the river water may contain up to 0.14 ug/liter asbestos. This corresponds roughly to about $1 \times 10^5$ fibers/liter. In making these calculations the staff has assumed that none of the asbestos eroded from the fill will settle out in the cooling tower basin or in the wastewater holding pond. Depending on the size of the particles, appreciable settling my occur, but the magnitude is presently not possible to predict. The staff is currently conducting an investigation into the contribution of cooling towers containing asbestos fibers have been detected in cooling tower blowdown samples analyzed for asbestos by transmission electron microscopy, electron diffraction, and energy dispersive X-ray analysis. The limits of detection in these investigations were on the order of $10^4$ to $10^5$ fibers per liter.

In the absence of any state or federal standards for asbestos in water, or conclusive evidence that asbestos in water on the order of 1 million fibers per liter presents a health hazard, the staff does not expect that asbestos (if any) added to the Verdigris River water by the cooling towers on the BFS, will, after mixing in the river, pose a health hazard to downstream users, provided that the concentration of asbestos in the ambient water, from natural or man-made sources upstream of the BFS, is less than 1 million fibers per liter.

This conclusion may need to be revised, if the extensive studies now going on at several institutions indicate that 1 million asbestos fibers per liter in drinking water pose a health hazard. It is expected that within the next year, long before the BFS towers are in operation, federal standards for asbestos in water will be set. At the time of application for an operation license, this question will be re-evaluated. Analysis of the ambient concentration of asbestos in the Verdigris at the BFS will aid in that evaluation.

Currently, there is no national ambient air quality standard for asbestos fibers, although a proposal is under discussion that would set the standard at 30 ng/m$^3$.[9] Nonurban and remote urban airborne asbestos concentrations are usually less than 1 ng/m$^3$. Urban areas are usually below 30 ng/m$^3$, except in heavily industrialized areas or at toll booths on highways.[9] By way of perspective, automobiles in Connecticut were reported to contribute 1.5 tons/year of asbestos into the air from brake linings.[9] National emission standards for asbestos do not include a concentration limit, but indicate that there shall be no visible emissions of asbestos.[10] It has been calculated that the maximum allowable emission rate that would be consistent with the proposed national ambient air quality standard of 30 ng/m$^3$ would be either 20 or 24 gram/day at a distance of approximately 300 or 350 ft from the source, respectively.[9] As outlined above in the staff calculations, the emission rate of asbestos in the drift plume from the BFS cooling towers is estimated to be 22.7 ug/min per tower. This corresponds to about 0.03 g/day per tower, and 0.2 g/day from the 6 towers. The latter figure is one hundreth of the proposed limit of 20 g/day. The staff is of the opinion, therefore, that the asbestos concentration in the drift plumes from the BFS towers will pose no health hazard to persons outside the site boundary.

## Literature Cited


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9. L. Bruckman and R. Rubino. Asbestos: rationale beind a proposed air quality standard. J. Air Pol. Contr. Assoc. 25:1207-1215, 1975.

10. National Emission Standards for Hazardous Air Pollutants. (40 CFR 61; 38 FR 8820, April 6, 1973.)


### 11.1.5.32 Effects of Radiation Exposure (YOUNGHEIN-A44)

The BEIR* Report presented an estimate of 200 cancer deaths to a population of one million receiving one rem. In easier terms, this reduces to .0002 cancer deaths per man-rem. One can apply this to the estimated doses to be received by the 50-mile population and the U.S. population. These population doses are presented in the environmental statement. By this method one would estimate that the Black Fox Station effluents will cause much less than one cancer death in either the 50-mile or U.S. population over the plant lifetime.

Using the same method, one would estimate that over the lifetime of the plant, occupational radiation dose will cause about 8 cancer deaths. When this number is compared to the large number of workers who will be exposed (as many as 1000-2000 over 40 years) and the average annual worker dose of about 1 rem, one can see that this represents a very small hazard to the individual worker. From this analysis one can see that the cancer risk to the public is negligible and the risk to the workers is minor.

*"The Effects on Populations of Exposure to Low Levels of Ionizing Radiation," Report of the Advisory Committee on the Biological Effects of Ionizing Radiations, Division of Medical Sciences, NAS/NRC, November 1972.

11.1.5.33 Dangers from Plutonium (YOUNGHEIN-A44)

Plutonium will be produced inside the reactor at Black Fox Station and it will not be perfectly contained. However, only a very small amount is expected to be released. Muc less than $10^{-5}$ curies per year per reactor unit will be released in the liquid effluents, and no plutonium has been measured in the gaseous effluents of a power reactor.

These amounts of plutonium are not quoted in the environmental statement because they are insignificant when compared with the total amount of all radioactivity estimated for the Black Fox liquid releases.

11.1.5.34 Allowable Effluent Releases (YOUNGHEIN-A45)

The per unit gaseous effluent limitations referred to in the comment are 10 millirad/yr airdose due to gamma radiation and 20 millirad/yr airdose due to beta radiation. The limit on doses to individuals from noble gases are 5 millirem/yr per reactor to the total body and 15 millirem/yr per reactor to the skin. As presented in Section 5.4, the staff's estimate of the total body and skin doses which individuals might receive at the Black Fox Station site boundary from noble gases are 0.98 mrem/yr and 2.0 mrem/yr, respectively. These doses are for both units; per unit doses would be one half of these doses. Also, these estimates have conservatism built into them such as maximum usage factors. The new EPA Standards referred to in the comment (25 mrem whole body from the fuel cycle) have not yet been finalized. The compliance of Black Fox Station with those EPA standards will be evaluated when the EPA standards are implemented.

In any case, the dose individuals might receive from Black Fox Station on a yearly average basis are much smaller than doses due to background radiation. The Environmental Technical Specifications will govern Black Fox Station operation. These specifications will be prepared after the BFS review at the operating license stage. They will be structured such that Black Fox Station would not be expected to exceed the design objectives doses on an average annual basis over the plant life. However, it is possible (but improbable) that in a particular year, doses which are a significant part of 500 mrem might be received by members of the public. Such individual doses are not considered dangerous and only because of the NRC policy of keeping doses "as low as reasonably achievable" are plants required to maintain lower individual doses on a time averaged basis.

11.1.5.35 Genetic Risk to Nuclear Workers (YOUNGHEIN-A45)

When one talks of genetic effects, one means mutations. There are many things in our everyday world which cause mutations. It is generally believed that natural background radiation causes only a small part of the spontaneous mutation rate (the normal mutation rate). Radiation induced mutations and spontaneous mutations are of the same type. There is not direct evidence that radiation causes human genetic effects. However, it is generally believed that radiation can produce genetic effects and that there is a linear dose-genetic effects relationship. The natural incidence of genetic-effects is 60,000 per million births (6%). A genetic effect is not serious, or even recognized, in all cases.*

NUREG-0002** presents an estimate of 258 total genetic effects per million man-rem. The average worker at a nuclear power plant receives 0.8 rem annually according to NUREG-0109.*** The environmental statement estimates 1000 occupational man-rem annually for Black Fox Station. Ten total genetic effects can be estimated due to the forty-year operation of the plant. On an individual basis, the estimate would be 0.003 effects for the average worker exposed to genetically significant exposure for 15 years.

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*"The Effects on Populations of Exposure to Low Levels of Ionizing Radiation," Report of the Advisory Committee on the Biological Effects of Ionizing Radiation, Division of Medical Services, NAS/NRC, November 1972.

**NUREG-0002, Final Generic Environmental Statement on the Use of Recycled Plutonium in Mixed Oxide Fuel in Light Water Cooled Reactors, U.S. Nuclear Regulatory Commission, August 1976.

***NUREG-0109, Occupational Radiation Exposure at Light Water Cooled Power Reactors 1969-1975, U.S. Nuclear Regulatory Commission, August 1976.

11.1.5.36 Problems of Waste Heat (YOUNGHEIN-A46)

A comment was made that insufficient discussion regarding the problem of waste heat was contained in the DES.

The extreme temperatures observed in July and August have been considered in the design of plant cooling systems. The plant's impact on temperature and humidity should only be observable within very close proximity of the cooling tower structures.

The frequency of variability of weather conditions are considered in design of the plants. BFS is designed for a 100-year drought rather than a 50-year drought as stated herein. Although Oologah Reservoir has conservation storage equivalent to a 50-year drought, the plant's requirements and the inclusion of onsite storage makes the design drought for the plant approximately once-in-100 years.

The heat dissipation system is discussed in Section 5.3. The expected thermal plume is extremely small and all state thermal water quality standards are expected to be met (see also Section 11.1.5.26).

The impacts of thermal effluents have been discussed in Sec. 5.6.2.2, and the staff concluded that no fish kills are expected from thermal additions. During the summer, there will be essentially no temperature difference between river ambient and discharge from BFS, due to retention of discharge in the wastewater holding pond.

11.1.5.37 Effects of Waste Heat on Weather Phenomena (YOUNGHEIN-A46)

The effects of waste heat on any modification of weather phenomena should only be observed in the limited area of the plant site and only to a very limited degree. When the heat introduced by a heat dissipation system into the atmosphere at a point is compared to the large scale energy transformations already in progress in the surrounding atmosphere, this source is completely masked. Thus, discernible changes in atmospheric phenomena, if any, on a large scale should not occur.

11.1.5.38 Releases of Krypton-85 (YOUNGHEIN-A46)

The environmental effects of krypton-85 (which is released into the atmosphere from nuclear fuel reprocessing plants and not from reactors such as BFS) are included in the assessment of the environmental effects of the fuel cycle and are discussed in Section 5.8.

11.1.5.39 Increases of Radioactivity in Water (YOUNGHEIN-A49)

The Black Fox Station pre-operational environmental monitoring program will determine the levels of natural radioactivity in the water of the Verdigris River. The operational program will determine the actual increases in the radioactivity of the water of the Verdigris River due to plant effluents. The doses which are presented in Section 5.4 of the environmental statement for persons drinking water from the Verdigris River are very low. Only the thyroid doses (less than 1 mrem per year) are greater than 0.01 mrem per year. The additional risk or damage from these doses will be small and insignificant as compared to the impact from doses due to natural radioactivity even if the levels of natural radioactivity are higher than the U.S. or Oklahoma averages.

11.1.5.40 Recreation on the Verdigris River (YOUNGHEIN-A49)

A comment was made that the quality of recreation on the Verdigris River would be lowered.

As described in Section 5.6.2.2, there will be essentially no heat added to the Verdigris River from BFS, during the summer and, thus, great increases in algal growth and eutrophication will not occur. Turbulence and turbidity are limiting factors to planktonic growth in the Verdigris (Sec. 2.7.2.5), and this fact, coupled with the small thermal plume (even during maximum river-discharge temperature differentials [Sec. 5.6.2.2]) would thoroughly discount algal growth increases from occurring due to waste heat production from BFS.

11.1.5.41 Relocation of Residents (PSO-A83)

The staff does not have any estimate of the number of persons to be relocated.

11.1.5.42 Receptors of Radiation Doses (PSO-A83)

For the purpose of dete.mining compliance of the Black Fox Station with the design objectives of 10 CFR Part 50, Appendix I, the staff has used the receptors presented in the ER as actual existing receptors. The doses presented in Tables 5.6, 5.8, 5.11, and 5.12 of this statement reflect the use of actual existing receptors as called for in 10 CFR Part 50, Appendix I.

11.1.5.43 Nearest Drinking Water Intake (PSO-A83)

As indicated in Section 5.4.1.3, the actual water intakes for Broken Arrow are located in the middle of an oxbow off the main channel of the Verdigris River. The actual Broken Arrow intake location is roughly two and one half mile downstream of the plant discharge. However, in calculating the dose from drinking water from the Broken Arrow intake, the staff and the applicant used the dilution factor and travel time estimated for the point where the oxbow breaks off from the main channel. That point is slightly over one mile (6300 feet) downstream of the plant discharge. The use of this point instead of the actual intake location results in a conservative dilution factor, travel time, and calculated dose.

11.1.5.44 Use of Polyolesters and Phosphonate Materials as Anti-scalants (PSO-A84)

The staff has reviewed the information supplied by the applicant concerning the toxicity and biodegradability of polyolesters and phosphonate materials proposed for anti-scalant use at BFS, 1 and 2. However, the staff does not believe the supplied information is adequate to assess the impacts resulting from the use of the proposed materials without further evidence to support their overall environmental acceptability.

The staff does feel that the supplied toxicity information indicates that the use of Nalco and Dequest compounts as anti-scalants would be safe in regards to acute toxic effects to fish. Information supplied by the applicant reveals that concentrations shown to be acutely toxic to fish, e.g., >1000 ppm for 96-hr $TL_{50}$ to bluegills and rainbow trout for Dequest 2000, are much higher than those resulting from anti-scalant use at BFS, 1 and 2. However, information is lacking concerning the concentration of the compounds that could produce acute toxicities to other groups of aquatic organisms, e.g., phytoplankton, zooplankton, and macroinvertebrates. As physical and physiological characteristics of these organisms differ from fish, doubt exists as to what concentrations of the compounds would be acutely toxic to them. Furthermore, as long-term use of the anti-scalants would be expected at BFS, 1 and 2, the staff is equally concerned with long-term chronic effects to aquatic organisms. Little information supplied by the applicant addresses chronic effects (effects on reproduction, development, disease resistence, etc.) and/or concentrations that elicit chronic effects on aquatic biota found near the BFS site.

The staff has been unable to obtain information (including that supplied by the applicant) detailing the physical-chemical properties of the scale inhibitors under actual use conditions. The existence of an increased amount of colloidal material resulting from the interactions of the anti-scalants and scale forming materials is probable, although no information is presently available on its nature and behavior. The effects that this colloidal material could have on aquatic biota, both in regards to its inherent toxicity and effects relating to increased susptability to disease, parasitism, etc., remain in question.

Of greater concern to the staff than the toxic action of the proposed anti-scalants, is their potential for causing nutrient enrichment impacts. The information supplied by the applicant, shows that both the Nalco and Dequest compounds biodegrade over time, producing orthophosphate as one of the end products. As the use of the anti-scalants would be a continuous operation during the life-span of BFS, 1 and 2, the staff is concerned over the quantities of orthophosphate that would enter the Verdigris River. The information supplied by the applicant indicates that the different Nalco and Dequest compounds have different rates of biodegradation and produce different concentrations of orthophosphate depending on the formulation used. The staff is therefore uncertain over the ultimate levels and fate of orthophosphate to be discharged into the river resulting from use of the proposed anti-scalants. The possibility exists that discharged anti-scalants could accumulate to orthophosphate could result in nutrient enrichment problems particularly in these areas.

The staff is also concerned that water quality standards and effluent regulations being established and imposed on municipalities to treat wastewater and control levels of compounds, such as phosphorus, released to receiving streams would not be imposed upon BFS, 1 and 2. Phosphorus-bearing compounds released into the Verdigris River that result from BFS anti-scalant use could result in nutrient-associated problems to the river and place an additional demand upon wastewater treatment facilities of downstream municipalities.

With the aforement. ned uncertainties concerning the use of the proposed anti-scalants for Black Fox, 1 and 2, the staff has added the following condition in Sec. 5.6.2.2: the applicant will be required to submit to the staff an evaluation of the anti-scalant of choice, demonstrating the overall environmental acceptability of that compound for use at BFS, 1 and 2, prior to issuance of an operating license.

The staff feels that the results given by the applicant in regards to the toxicity and biodegradability of the polyolester and phosphonate material are not adequate to warrant their use as anti-scalants for BFS without further demonstration of their safety. The staff is concerned with the short-term and long-term effects of these materials to other aquatic biota, i.e., phytoplankton and zooplankton. Additionally, laboratory bioassay tests that have been performed did not incorporate other materials that would be present in the BFS discharge, nor did they simulate water quality conditions present in the Verdigris River. Little is thus known as to exactly how the anti-scalants would behave in the Verdigris River system. Additive and/or synergistic interactions could result with other compounds and ions in the BFS discharge and river. Based on the above staff's position as stated in paragraph 7, Section 5.6.2.2, remains unchanged.

### 11.1.5.45 Buildings Under or Near Transmission Lines (PSO-A84)

The staff believes that chicken barns constructed with wood columns and sheet metal roofs and sides are unusually large buildings. Furthermore, the number of such barns along the Arkansas portion of the transmission corridors, and the short lead time required for new construction precludes treating these as special cases. During informal discussions at the site visit, PSO's staff concurred with the staff concerns about these barns. The total length of the corridor of concern (ROW sections XIIa and XIIb) is less than 40.6 miles (65 km), so this requirement is not "unduly restrictive."

The disagreement is simply a matter of whether the inspection should extend to 30 meters or 100 meters from the right-of-way. Induced currents can be modeled mathematically and it should be simple to decide on an appropriate distance for inspection and grounding. It is our general experience that let go thresholds of about 5 ma will not be exceeded outside the usual right-of-way and that grounding at lower field strengths is not needed.

### 11.1.5.46 Aquatic Impact of Zero Flow (SCHMELLING-A69)

This environmental statement does not contain a discussion of aquatic impacts under the hypothetical conditions of essentially zero flow.

Discharge;

The staff acknowledges that if a station operation, under such hypothetical conditions, would continue over a prolonged period of time (beyond that required to fill the holding pond to its ultimate elevation) adverse impacts to the aquatic biota in the vicinity of the station discharge could occur. However, station operation will be curtailed prior to the time that the holding pond would be completely filled; thus no adverse effluent discharge impacts will be permitted to occur. The details of such curtailment procedures will be imposed in the Technical Specifications section of the operating license.

Intake:

The staff also acknowledges that adverse entrainment impacts could occur under the hypothetical, rare conditions of prolonged drought, decreased water quality, prolonged period of no lockage for river traffic, and other factors; however, the uncertainties of predicting the magnitude and time frame of such conditions as well as the technical difficulties of predicting the type and magnitude of impacts which would be likely to occur are sufficiently great not to warrant the effort at this time. However, if conditions that could significantly impact the Verdigris River aquatic life by entrainment would occur, curtailment of operation would be imposed by the Technical Specifications of the operating license. The availability of water for operation of the Black Fox Station is essentially independent of the flow history of the Verdigris River, because the source of water will be purchased releases from the Oolagah Reservoir, potentially supplemented by effluent releases from the City of Tulsa. Thus, the channel of the Verdigris River will merely act as the conduit of delivery. For these reasons power plant siting criteria based solely on river flow characteristics are not applicable in this case.

### 11.1.6 Environmental Measurements and Monitoring Programs

#### 11.1.6.1 Carbon-14 Monitoring (ERDA-A95)

It was suggested in this comment that there be some indication in the FES as to whether or not specific carbon-14 monitoring is planned.

As shown in Table 6.2, no specific carbon-14 monitoring is planned. The doses from carbon-14 to individuals living near the site will be very small, less than one mrem/year.

Carbon-14 will predominate the population doses from BFS effluents. However, environmental carbon-14 monitoring would not yield significant information about the amount of carbon-14 entering the food pathways for the general population.

### 11.1.7 Environmental Impact of Postulated Accidents Involving Radioactive Material

#### 11.1.7.1 Evacuation Plans and Emergency Medical Services (FUNNELL-A97, HEW-A94)

The staff recognizes the safety significance of this issue which is being considered in our safety review of the application and which will be discussed and made public in the Safety Evaluation Report.

#### 11.1.7.2 Accidental Release of Liquid Waste (YOUNGHEIN-A44) (EPA-A103) (CASE-A74)

This comment concerned unplanned discharges of radioactive waste water in general and at the Vermont Yankee Nuclear Plant and Hanford in particular.

The unplanned liquid waste releases are included with anticipated operational occurrences in the liquid source term and shown in Table 3.4. In Section 5.4, the dose impact has been determined and evaluated for the Black Fox Station using this liquid source term.

In the case of Vermont Yankee any discharges from the facility not specifically covered by a discharge permit issued by the State of Vermont is in direct violation of state regulations and must be reported to the applicable state governing agency. Along with notifying the state agencies Vermont Yankee has routinely, through the press media, notified the public. Events of this type are normally followed by a qualitative assessment of the event and the results transmitted to the applicable state agency, which in turn, again through the press media, notifies the public. When state regulations are violated, the violator is subject to civil penalties and in the case of Vermont Yankee, two of three inadvertant releases have been the subject of law suits initiated by the State of Vermont against the utility.

In accordance with Federal Regulations whenever specifications, established to protect the environment and the health and safety of the public, are violated the utility must notify the NRC Office of Inspection and Enforcement. This initiates an investigation by that office into the causes and effects of the event. Additional exchanges of information and subsequent analyses may be required depending on severity of the event. At the completion of the investigation enforcement actions wnich, again depending on the severity of the event and the underlying causes, may lead to civil penalties. All of the information reported and exchanged is made part of the public record and is available to interested parties. In the case of Vermont Yankee, the utility was cited for procedural deficiencies.

The Hanford explosion and the 85,000-gallon Vermont Yankee release resulted in very small releases of radioactivity. While the Vermont Yankee release involved much water, the amount of radioactivity was less than 2 curies of tritium and about 0.0005 curies of other radionuclides--less radioactivity than the plant normally releases in a year. Thus, doses and genetic risks from these accidents were of the same order of magnitude as for routine releases. See also Section 11.1.5.35 for staff's response on genetic risk.

In the event of a serious accident such as a core-melt with a ruptured containment, deaths and other health effects including genetic effects would result. However, such accidents have an extremely low probability of occurrence (cf. WASH-1400).

11.1.7.3 Probability of An Accident (CASE-A75)

A comment was received that too much emphasis has been placed on the Reactor Safety Study (WASH-1400) in theorizing the low probability of an accident. Staff points out that, although the Reactor Safety Study is the most exhaustive and detailed study performed to date on the risks of nuclear power plant accidents, and has received a broad and increasing endorsement by the informed scientific community, the staff does not rely upon that study to license a nuclear power plant. The staff requires, in its safety review, that plants be designed with a large number of elaborate and redundant safety systems and relies upon the actual design, quality assurance during construction, preoperational testing and operational maintainability of these plant systems to assure that accident risks will be acceptably low.

11.1.7.4 Effects of Tornado (YOUNGHEIN-A46)

A question was raised on the effects of a severe tornado and whether missile penetration or a vacuum causing high releases of radioactivity was a possibility. All nuclear power plants are required to be designed against the effects of a severe tornado considered characteristic for the area. The design basis tornado specified for the Black Fox site is one assumed to be moving at a speed of 70 pmh and with a rotational velocity of 290 mph at a radius of 150 feet from the center. A pressure drop of 3 psi in a time period of 1.5 seconds is assumed. All safety related systems and components whose failure or damage could release substantial amounts of radioactivity will be enclosed in structures capable of safely withstanding the effects of the above tornado. A representative spectrum of missiles such as poles and pipes is assumed to be lifted by this tornado and the plant structures are designed to withstand the impact of these missiles without penetration. While transmission lines could be disrupted by such an event, all nuclear power plants are also required to have internal emergency power systems which are sufficient to operate safety-related systems for an extended period.

11.1.7.5 Hazards of Nuclear Reactors (YOUNGHEIN-A48)

A comment was made that the hazards of nuclear reactors have been underestimated, that they contain large amounts of radioactivity, and can never be considered without risk. The staff agrees that nuclear reactors contain large inventories of radioactivity and cannot be considered totally free of risk. Nevertheless, the staff does not believe that the hazards of nuclear reactors have been underestimated. The special hazard associated with nuclear reactors is that of a large accidental release of radioactivity. This hazard has been addressed and estimated in the Reactor Safety Study (WASH-1400) where it concluded that the risk from this hazard was low. The staff agrees that elaborate and redundant safety systems to reduce this risk to an acceptably low level are not a luxury, and routinely requires such systems for all nuclear power plants.

The question of whether Dr. Rasmussen's being selected to head the Reactor Safety Study would present a conflict under applicable law was reviewed by the predecessor AEC at the time he was selected. This review did not disclose a potential conflict of interest and the statutues. See Section 11.1.7.3.

11.1.7.6 NRC Publication "Nuclear Safety" (YOUNGHEIN-A49)

The incidents listed in the NRC publication "Nuclear Safety" have been abstracted from reports submitted to the Commission. These incidents range from trivial or routine to some which are considered significant. A primary purpose of publishing a listing of such incidents is to facilitate the exchange of information among those engaged in designing, building, and regulating nuclear power. To publish the complete report of each incident in a publication such as "Nuclear Safety" would not be feasible and would negate the usefulness of the publication. The full reports are readily available to any member of the public who is interested in obtaining more in-depth information on any particular incident.

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### 11.1.8 The Need for the Plant

#### 11.1.8.1 Off-system Sales (SC-A-72)

Off-system sales are common throughout the electric utility industry because they lower the cost of electricity by obviating the need for generating capacity that would lie idle much of the year. If PSO did not export power, other facility would have to be built to supply the need that PSO satisifies. The staff does not believe anyone would deny the applicants the right to purchase power from other utilities to satisfy their own ultimate consumers. Since the practice of selling power for resale is legal, proper, beneficial, and widespread, the staff sees no reason to object to PSO's sales.

#### 11.1.8.2 Proposed Northeast Plants 3 and 4 (DOI-A107)

The applicant's proposed Northeast Plants 3 and 4 will be located about 22 miles north/northwest of the BFS. Units 3 and 4 will share the site with two existing gas-fired units. According to information supplied by the applicant (letter of September 23, 1976 to NRC), Units 3 and 4 will have a capacity of 450 MWe each. The units will be cooled by mechanical-draft wet cooling towers of the conventional rectangular arrangement and share a single 600 ft. smoke stack. The units will burn low-sulfur Wyoming coal. The scheduled dates for commercial service are June 1, 1979 and June 1, 1980. According to the letter, the effluents from this plant will meet applicable emission standards without scrubbers.

Cooling Tower Plumes

A chemical interaction between the cooling tower plumes from BFS with effluents from the Northeast plant could occur when the two plumes merge. Merger of the plumes from the BFS with that of the Northeast plant is possible only when the winds are from the NNW (about 6% of the time) or the SSE (16% of the time). The frequency of plume merger will be further reduced by the difference in release heights of the two effluents (60 vs. 600 feet) and plume rise. Thus, physical merger of the two plumes will be infrequent.

Under neutral and unstable weather conditions, the effluents from one source will become very dilute in traveling the 22 miles between sources and disperse vertically into the other plume. The dilution rate is increased by the average strong winds characteristic of Oklahoma. With SSE winds, the moisture added by the BFS cooling towers will be very small compared to that contained in the ambient atmosphere. Under stable weather conditions and weak to moderate winds, the vertical dispersion of the two plumes will be reduced. However, the difference in height of release will prevent the two plumes from merging and no interaction will occur.

For the reasons cited to above, the staff expects no effects due to the merger and chemical interactions of the cooling tower plumes with the effluents of the coal-fired Northeast Units 3 and 4.

Discharge Plumes in the River

The staff cannot justifiably discuss the possible interaction and resulting environmental effects of BFS with the proposed Northwestern plants 3 and 4. The thermal and chemical plumes from BFS, 1 and 2, will be small, and the staff has concluded that no deleterious impacts will occur to biota in the Verdigris River. It is doubtful that any interactions with the Northwestern plants 3 and 4 will occur in this regard.

#### 11.1.8.3 Advantages to Local Communities (YOUNGHEIN-A47)

The total cost of electricity is generally lower for large steam-electric plants than for smaller plants. While it is true that some persons feel there are disadvantages due to construction and operation of the power plant, there are also advantages to local communities in terms of tax payments by the utilities which are borne by all rate payers throughout the service areas to be served by the station. Other local residents will receive benefits in terms of employment or additional business income either directly or indirectly as a result of plant construction and operation. The capacity of Northeast 3 and 4 and the Black Fox Station will supply electricity to all of the PSO's service area not just the customers who reside in the county, where the generators are located.

11.1.8.4 Growth in Energy Demand (YOUNGHEIN-A47)

In the staff's evaluation even a modest growth in electricity demand coupled with the highly desirable goal of reducing the use of natural gas for electricity generation indicates a need for the addition of the BFS.

11.1.8.5 Need for Plant (SCHMELLING-A69)

See Section 8.2 for the staff's discussion of conservation and Section 9.1 for the staff's discussion of alternatives.

11.1.8.6 Population Growth (PSO-A85)

The staff believes that a reasonable assumption is that demand in the PSO service area will be the same as the national average. However, this forecast is more likely to be too low than it is to be too high. Recent indicators show population and income growing more rapidly in Oklahoma than they are for the nation. (U.S. Department of Commerce News, BEA 76-65, September 15, 1976.) Total personal income in the U.S. increased 19% between 1973 and 1975, while for Oklahoma, this figure was 23%. A continuation of this trend would likely be a factor causing higher than average rate of increase in electricity use. The staff concludes, however, that even with the more modest growth rates forecasted in the DES by the staff, the construction schedule planned by the applicant should be maintained in order to replace generation by natural gas units now on the system.

11.1.9 Alternatives

11.1.9.1 Energy Conservation (YOUNGHEIN-A47) (CASE-A75) (FUNNELL-A97) (SC-A72)

See Section 8.2 for the staff's discussion of conservation.

11.1.9.2 70% Capacity Factor (DOI-A107)

See Appendix J for discussion of capacity factors. See also response 11.1.10.7.

11.1.9.3 Cost of Cooling Ponds (DOI-A108)

In areas where sufficient flat land near the plant can be purchased at moderate (farm-land) prices, a cooling lake usually costs slightly less than would evaporative cooling towers.*,** As indicated in Section 9.3.1.6, a cooling lake could be constructed with the purchase of an additional 1500 to 2000 acres of land. Additional, unknown, costs would arise due to plant redesign, raising the plant 6 feet (to get the power center above the flood plain of the pond), escalation due to a one-year delay, construction of the dikes to contain the lake, lining the pond to prevent seepage, additional pumping, maintenance, etc. These costs would be very site-specific and estimating them would require a detailed engineering analysis. The staff does not consider the environmental advantages of a cooling pond over the CMDCTs selected to justify the economic penalty involved in the delay and to justify the use of the additional land.

11.1.9.4 Uranium Requirements (MALES-A5)

Our estimate that 11,800 MT of uranium would be required to supply each unit of the Black Fox is based on Table S-1 of WASH-1248. The table was developed to reflect an average LWR. We have substituted a paragraph based on the figures for a BWR that appear in Table 12 of WASH-1139 (74).

The 0.37% tails assay for ERDA enrichment services customers is not now expected. This is because Congress has directed ERDA to construct an 8.75 million SWU addition to its Portsmouth, Ohio facility. With the addition to that plant, it is expected that ERDA enrichment services customers will be served at a tails assay of about 0.25%.

* "Industrial Waste Guide on Thermal Pollution," Federal Water Pollution Control Adm., Corvallis, Oregon, Sept. 1968.

** Draft Environmental Statement, Wolf Creek Generating Station, Docket No. STN 50-482, U.S. Nuclear Regulatory Comm., Washington, D.C., July 1975.

11.1.9.5 Decommissioning (CASE-A75) (MALES-A6) (YOUNGHEIN-A49)

Mr. Scaletti, in his testimony before the Atomic and Licensing Board in the matter of Wolf Creek Generating Station, Unit No. 1, Docket No. STN 50-483, estimated decommissioning costs ranging from $1 million plus an annual maintenance expense of $100,000 per year for the lowest level of decomissioning to a cost of 83.4 million for complete restoration of the site.

Using 83.4 million as present cost of decommissioning and a 5% long-term escalation rate over 40 years (10 years to commercial operation plus 30-year plant life), the decommissioning cost would be $58/ million at the end of plant life in year 2015. The annual sinking fund payment required over 30 years at a 10% interest rate to produce this amount is $3.57 million per year. This sinking fund payment would add about .48 mills/kWh to the cost of electricity if the nuclear plant was operated at 70% capacity factor (.67 mills/kWh at 50% capacity factor).

11.1.9.6 Rise in Electricity Rates (MALES-A7)

The staff assumes that the source of these assertions is an article by Bob Myove which appeared in the Tulsa World on April 8, 1976. The following appears in this article: "PSC [PSO] estimates the average electric bill will rise 30% in the next five years and 75% in the next ten years." PSO has told the staff that the price increases mentioned in the article are in nominal dollars and represent estimated revenue needs before inflation is taken into account. At an assumed rate of inflation of 6% per year, all other prices will rise 34% at the end of five years and 79% at the end of ten years. Thus, the staff does not see PSO's possible price increase as significant.

11.1.9.7 Uranium Availability (YOUNGHEIN-A48) (MALES-A7)

The most comprehensive and authoritative appraisal of U.S. uranium resources and their availability results from the work of the U.S. Atomic Energy Commission and the U.S. Energy Research and Development Administration. Their evaluations are based on extensive field studies and resource appraisal efforts extending over 30 years. The evaluation of uranium resources in the Black Fox Environmental Statement is based on ERDA studies.

A number of workers have reviewed available data and expressed opinions regarding the uranium supply outlook. Some have little or no experience in uranium and sometimes no experience in raw materials. Many of those expressing a somewhat negative viewpoint compared to ERDA findings have been cited by Mr. Males in "Analysis." There are also workers who have expressed opinions of a more optimistic nature than ERDA. A few of these would be Brinck, Erikson, Searl, Holdren, Cochran, Bupp, and Chow.

Pessimistic views usually are based on improper analysis of ERDA published exploration, discoveries and production data and not on field evidence. Such analyses of historical data have not given proper consideration to increased drilling depths, inflation and the lack of a normal commercial market. Proper analysis of the history of uranium exploration and the resource position should provide encouragement about future developments.

In regard to comments on low grade ores, such ores can be attractive both from the standpoint of economics and net energy output. Analysis of sources such as Chattanooga shales at 60-70 ppm shows they would produce considerably more energy than required for their use.

Foreign uranium can serve as a supplemental source for U.S. buyers. Contracts for over 40,000 tons $U_3O_8$ have been made by U.S. buyers with Canadian, Australian, South African and French suppliers. Prospects for expanded foreign supplies and additional procurement are good.

Breeders can have no significant impact on uranium supply before the year 2000.

In summary, extensive study of U.S. resources provides a sound basis for assessing future uranium supplies. Only a portion of currently estimated U.S. resources will be needed to fuel planned plants. Appraisal of U.S. resources continues and additional resources are being found. Additional supplies could be obtained if needed from higher cost and foreign resources.

11.1.9.8 Proposed Transmission Routing (PSO-A86)

While it is true that the upland woods immediately off the BFS site is not designated as mesic or xeric, there was no available data to make the required distinction. Rather than require PSO to sample this woodland to determine its exact composition, the staff utilized a worst case analysis.

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Because of other factors (discussed below), the conservative evaluation is that the proposed transmission line does cross an upland wood habitat which is not known to be xeric.

Immediately west of and contiguous with this undetermined woods along Commodore Creek, there is a "tall riparian woods" (staff observations at the site visit). In addition to this, there are rocky bluffs along the east side of the Verdigris River adjacent to the undetermined upland woods; and bluffs are also mentioned in A. C. Bent's discussion of Southern Bald Eagle preferred habitat.* Staff's observations from a helicopter overflight at 500 to 700 feet above ground during the site visit suggest that the undetermined upland woods is more likely to be mesic than xeric.

The staff is willing to re-evaluate this area as a potential habitat for Southern Bald Eagles, but would require (a) an original of "Attachment 4," (b) actual vegetational data from the referenced woods, (c) a description of the sampling regime for the vegetational data in sufficient detail to allow staff verification that the samples were not biased toward drier sites within the woods (the onsite mesic woods samples were biased toward the drier sites), and (d) actual vegetational data, including tree heights, from the riparian woods to the west of the undetermined upland woods.

### 11.1.10 Evaluation of the Proposed Action

#### 11.1.10.1 Cost-Benefit Analyses (SC-A71)

Comment was made that the cost-benefit analysis is distorted as a result of inadequate analysis of the cost of water.

Final water cost figures have not been estimated. However, it is incorrect to allege that this omission totally distorts the cost-benefit analysis. As an example, charges currently being made for water by the Delaware River Commission would add less than a tenth of a mill per kWh to the BFS costs.

#### 11.1.10.2 Hold Harmless Agreement (SC-A71)

Details of the water supply contract between the City of Tulsa and PSO are not known at this time since the agreement has not been reached.

#### 11.1.10.3 Use of BFS Site for Recreation (DOI-A108)

The staff is aware of no program for public use of the BFS site, including recreation. For this reason it is inappropriate to modify the given statement.

#### 11.1.10.4 Capital Cost (YOUNGHF [illegible] 8) (MALES-A4)

The capital cost for nuclear generating units in the DES appears to be low when compared to recent studies. A study ("Economic Comparison of Baseload Generation Alternatives for New England Electric" by Arthur D. Little, Inc./S. M. Stoller Corp.) issued in March 1975, analyzed several reasonably current nuclear plant estimates by five A/E firms, a reactor manufacturer and the AEC. These estimates were normalized to a 1974 dollar basis (two units, 1150 MWe each), and the average cost was determined. The average cost was escalated to commercial service dates of 1983 and 1985 using separate escalating factors for materials, equipment, and labor. The most probable capital cost estimate was 863 $/kW, the low variant was 777 $/kW and the high variant was 992 $/kW.

The CONCEPT Code at ORNL is in the process of being updated. The new cost model for the BWR will not be available until sometime next year, but the new cost model for a PWR plant with mechanical draft cooling towers has recently been developed. The total cost for a PWR is fairly similar to a BWR. Therefore, the CONCEPT calculations for Black Fox which are presented in Table 9.1 were redone (see also Appendix H). Using the new cost model for a PWR plant, the comparison for Black Fox is shown in Table 1. The new cost model shows a considerably higher cost, 165 $/kW.

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* A. C. Bent, Life Histories of North American Birds of Prey, Part 1, Dover Publ., N.Y., 1961.

The new cost estimate agrees fairly well with the above study results for the most probable case--863 $/kW vs. 840 $/kW. The escalation factors and interest during construction for the two estimates were similar.

Table 1. Comparison of Costs Estimated With CONCEPT-IV BWR Cost Model With Preliminary New PWR Cost Model for Black Fox Unit 1

(October 19, 1976)

| | CONCEPT IV June 8 | New PWR |
|---|---|---|
| Net capability, MWe | 1220 | 1220 |
| Direct costs (millions of dollars)* | | |
| Land and land rights | 1 | 5 |
| Structures and site facilities | 60 | 93 |
| Reactor/boiler plant equipment | 118 | 139 |
| Turbine plant equipment | 120 | 121 |
| Electric plant equipment | 45 | 38 |
| Miscellaneous plant equipment | 7 | 11 |
| Subtotal | 351 | 407 |
| Spare parts allowance | 5 | 6 |
| Contingency allowance | 35 | 40 |
| Subtotal (direct costs) | 391 | 453 |
| Indirect costs (millions of dollars)* | | |
| Construction facilities, equipment, and services | 23 | 76 |
| Engineering and construction management services | 57 | 81 |
| Other costs | 18 | 4 |
| Subtotal (indirect costs) | 98 | 161 |
| Total costs (millions of dollars) | | |
| Total direct and indirect costs* | 489 | 614 |
| Allowance for escalation | 111 | 133 |
| Allowance for interest | 224 | 278 |
| Plant capital cost at commercial operation | | |
| Millions of dollars | 824 | 10[illegible] |
| Dollars per kilowatt | 675 | 840 |

*In 1976 dollars.

11.1.10.5 Costs of Ownership (YOUNGHEIN-A48) (MALES-A4)

Black Fox Station (BFS), Unit 1 and 2, is an integral part of planned generating facilities to supply capacity and energy to the systems of Public Service Company of Oklahoma (PSO), an Oklahoma corporation with corporate offices in Tulsa, Oklahoma; Associated Electric Cooperative, Inc. (Associated), a Missouri corporation with corporate offices in Springfield, Missouri; and Western Farmers Electric Cooperative (Western), an Oklahoma corporation with corporate offices in Anadarko, Oklahoma. PSO will own an undivided 60.87 percent interest, Associated will own an undivided 21.[illegible]4 percent interest, and Western will own an individual 17.39 percent interest in each unit.
Direct costs (millions of dollars)*

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The cost of money for PSO is 14.25%, Associated is 8.5%, and Western is 8.0%. The corresponding sinking fund fraction for depreciation for each of the utilities is .27%, .81%, and .88%. The total for cost of money plus depreciation is 14.52% for PSO, 9.31% for Associated, and 8.88% for Western. The pro-rated cost of money plus depreciation based on the ownership fraction is 8.84%, 2.02%, and 1.54% respectively or a composite total of 12.4%, for BFS Unit 1 and 2. Since the station will be on the PSO system, an allowance for property insurance of 0.25%, and property tax of 2.50% for the BFS location must be added (interim replacement is assumed to be included in operation and maintenance cost and nuclear liability and decommissioning cost are shown separately for nuclear plants, since these charges apply only to nuclear plants, they should not be incorporated into the fixed charge rate). Thus, a reasonable fixed charge rate for BFS Unit 1 & 2 would be 15.15% (12.40% + 2.50% + 0.25%). Although the applicant has chosen to use a fixed charge rate of 20% in the ER, the staff considers the 15.15% to be more realistic and will use it in generating cost calculations.

11.1.10.6 Unit Costs (YOUNGHEIN-A48) (MALES-A5)

The fixed cost of a power plant will reamin the same whether the plant operates or not. Thus, the unit cost (mills/kWh) of the fixed cost portion of power generation will vary inversely with the capacity factor. The variable cost portion of power generation will vary linearly with capacity factor so that variable portion of the unit cost (mills/kWh) will remain constant with varying capacity factors. The fixed cost of power generation consists of the fixed charges (interest charges on investment, depreciation, property tax, income tax, and insurance) on the capital cost of the plant, and a portion of the fuel, operation and maintenance cost. The percent of total generating cost that is fixed will vary from generating station to station depending on such things as, the fixed charge rate, the capacity factor, Pu recycle, high or low sulfur coal, and local transportation cost. The following table shows the order of magnitude of fixed and variable cost as a percent of total generating cost at a 70% capacity factor. Note that the percent of fixed cost for a nuclear plant is about twice the fixed cost for a coal plant. Thus, a nuclear plant is more sensitive to capacity factor than a coal plant and there is a greater economic incentive to operate the nuclear plant at as high a capacity factor as possible than there is to operate a coal plant. Furthermore, the pay out from efforts to improve the capacity factor of nuclear plants is about twice that for a coal plant.

FIXED AND VARIABLE COST AS A PERCENT OF TOTAL GENERATING COST AT A 70% CAPACITY FACTOR

| | | COAL | |
|---|---|---|---|
| FIXED COST | NUCLEAR | LOW SULFUR | HIGH SULFUR |
| Fixed charge | 45-70 | 30-40 | 30-40 |
| Fuel-Fixed | 5-20[1/] | negligible | negligible |
| O&M Fixed | 6 | 4 | 4 |
| | 56-96 | 34-44 | 34-44 |
| VARIABLE COST | | | |
| Fuel-variable | 15-30 | 55-65 | 45-55 |
| O&M-variable | 2 | 3 | 15 |
| | 15-32 | 58-68 | 60-70 |

[1/] The larger percentage is for no fuel reprocessing or Pu recycle.

The comment seems to be based on the misconception that a nuclear plant must be refueled each year, regardless of the amount of unused fuel remaining in the core loading. That is, a nuclear plant operating at a high capacity factor would burn up more uranium than a plant operating at a low capacity factor over a given period of time. This cor[illegible]ion is wrong. A nuclear plant need not be refueled each year. A nuclear plant may continue t[illegible] operate until its fuel is used up.

In an actual situation, factors external to the plant may dictate the nuclear plant refueling schedule. For example, the maintenance schedule of the nuclear unit as well as other generating units on a utility system and the time of year when the peak demand for electricity occurs may determine whether a nuclear plant is shut down early for refueling or left on-line as long as economically possible.

11.1.10.7 Capacity Factor (YOUNGHEIN-A48) (MALES-A5)

The summary of a staff study on baseload steam-electric plant capacity factors is enclosed as Appendix J. This presents results of a statistical analysis of coal and nuclear historical capacity factors of plants above 500 MWe. The summary briefly explains procedures for correctly specifying the statistical analysis to be performed and the results of such an analysis. The conclusion is that for coal plants the capacity factor is 56 ± 13% at a 95% prediction interval, and for nuclear plants, the capacity factor is 54 ± 14% for the same prediction interval. The width of these prediction intervals shows that a considerable shift would be required before there would be a statistical basis for predicting different capacity factors for coal and nuclear plants.

As indicated in Section 11.1.10.6, the low operating costs of nuclear plants provides a high incentive to operate at high capacity factors compared to coal plants which have higher operating costs.

The recognition of the importance of improving the capacity factor of nuclear plants is indicated by the number and types of programs being initiated by industry, private institutions and Federal agencies. FEA established in early 1974 an Interagency Task Group on Power Plant Reliability. The Task Group's objective was to broadly define the principal causes of apparently poor operating records and possible corrective actions related to nuclear and large fossil unit operation. The FEA Task Group "Report on Improving the Productivity of Electric Power Plants," was issued in March 1975.

The American Nuclear Society and Edison Electric Institute co-sponsored an executive conference on Improving Power Plant Reliability in September 1976 where a number of utilities, A and E firms and manufacturers of nuclear steam supply systems, steam turbine-generator sets, and other power plant equipment discussed programs to enhance the reliability and productivity of nuclear and coal-fired electric power generating units. The paper attached to the comment "New Directions Needed to Improve Power Plant Production" presents a sampling of the broadly based and expanding interest in this subject. The estimates of potential benefits of improved productivity are discussed and several independent estimates are presented in Figure 1 of the attached paper. Also presented is a discussion and a summary of performance goals (Figure 2) for various organizations. The FEA goals are a 1985 target of an industry-wide average of a 12% forced outage rate, an 80% availability factor and a 70% capacity factor for nuclear units and for coal-fired units 390 MW and larger.

The staff believes that a reasonable range of capacity factor expectations for BFS is 50% to 70%. There is substantital economic incentive to improve nuclear power plant capacity factors because of the very low cost of operation compared to other alternatives. Thus, there is likely to be an improvement in capacity factors in the future. The historical experience with plants over 1000 MWe is insufficient to make conclusions from a simple average of capacity factors to date.

11.1.10.8 Operating Lifetime (MALES-A6)

The breakdown of the direct capital cost of nuclear and coal power generating stations is shown in the following table as a percent of total direct cost.

| Account No. & Description* | Percent of Total Direct Cost: Nuclear PWR or BWR | Low Sulfur | High Sulfur |
|---|---|---|---|
| 20. Land & land rights | 1% | 1% | 1% |
| 21. Structures & site fac. | 23 | 14 | 14 |
| 22. Reactor (Boiler) Plant equip. | 34 | 41 | 45 |
| 23. Turbine Plant equip. | 30 | 35 | 30 |
| 24. Electric plant equip. | 9 | 7 | 9 |
| 25. Miscellaneous plant equip. | 3 | 2 | 2 |

*For a complete listing of items included in each account, see NUS-531, "Guide for Economic Evaluation of Nuclear Reactor Plant Designs."

Approximately 34% of the direct capital cost of a nuclear plant is associated with the nuclear reactor. The remaining costs are for equipment and materials that are the same as those found in a coal plant. Since the nuclear plant design is subject to safety review by NRC, reactor and other components in a nuclear plant must meet certain standards. Also, there is a quality assurance and inspection program for nuclear plants. None of these are imposed on coal plants by NRC or other agencies, therefore, it can be argued that a nuclear plant should have a longer life expectancy than a coal plant. However, in view of the fact that about 2/3 of coal or nuclear plants are composed of the same kinds of materials and equipment, their lifetimes should be the same for economic comparisons even though the reactor portion of the nuclear plant could have a longer life. For economic comparisons between nuclear and coal plants, the NRC staff uses a 30 year life for both types of plants.

11.1.10.9 Nuclear Fuel Costs (YOUNGHEIN-A48) (MALES-A6)

Table 9.1 in the DES has an error in footnote b. Nuclear fuel costs, except for uranium, were escalated at 8%/year through 1982 because of recent high rates of escalation and the prospect that these will continue for the immediate future. The 8% was selected on the basis of the staff's conclusion that this rate as used in WASH 1174-74 was reasonable for reflecting current escalation. Uranium costs were forecasted differently. An analysis of current production costs, reserves and price trends led the staff to forecast a price of $40 per pound of $U_3O_8$ in 1982. Beyond 1982, all nuclear fuel costs are escalated at 5%/year. The 1984 cost estimates as a result of these escalation rates are: $U_3O_8$, $45 per pound; conversion of $UF_6$ $2.83/lb. U; enrichment, $142 per kg SWU; and fabrication, $188 per kg U; and shipping and reprocessing spent fuel, $275 per kg U. The staff does not foresee $U_3O_8$ prices rising as rapidly as some current market indicators show. The modest growth in nuclear reactors indicate adequate domestic uranium supplies for a considerable period into the future. These factors were used to derive the nuclear fuel cost of 8.1 mills per KWh in 1984 dollars shown in Table 9.1.

ERDA enrichment services charge will escalate as power and other costs for operating the ERDA enrichment plants escalate. These costs comprise about 2/3 of the charge, the other 1/3 being depreciation on capital and inventory carrying costs. Staff beleives that an escalation rate of 5% per year is appropriate for the enrichment services charge.

Uranium prices have increased sharply in the last few years. In view of this past increase and considering increased U.S. uranium exploration and production activities and an improving supply situation, much lower future price growth is expected.

11.1.10.10 Coal Plant Capital Costs (MALES-A6)

The Arthur D. Little study mentioned in Section 11.1.10.4 regarding nuclear plant capital cost, also reviewed estimates for fossil plant capital cost. For three sets of architect engineer's estimates, there is good correlation in the ratio of fossil station costs to nuclear station cost in 1974 dollars. The nuclear station consisted of two 1150 MWe units and the coal station consisted of 3 units of 800 MWe each. For coal plants with $SO_2$ scrubbing equipment the capital cost (in 1974 dollars) is about 91% of the nuclear plant cost and for coal plants without $SO_2$ scrubbing equipment the capital cost (in 1974 dollars) is about 76% of the nuclear plant cost.

The station cost (1974 dollars) was broken down into direct cost (materials, equipment and labor) and these escalated to 1983-1985 commercial operation dates. The range of capital cost estimates is shown in the following table for 3 units, 800 MWe each.

| Coal Station Three 800 MWe Units | Low Estimate | Most Probable | High Estimate |
|---|---|---|---|
| With $SO_2$ scrubber $/kW | 641 | 697 | 802 |
| Without $SO_2$ scrubber $/kW | 537 | 565 | 593 |

The CONCEPT Code using approximately the same escalation factors (6%/year for equipment, 7.4%/year for labor, 4.3%/for materials) as Arthur D. Little (5.6%/year for equipment, 8.3%/year for labor, 4.2%/for materials) generated a cost of 523 $/kW without $SO_2$ scrubbers and 565 $/kW for a station with $SO_2$ scrubbers for 1983 and 1985 operation.

The applicant's estimate for two 650-MWe units without $SO_2$ scrubbers was 460 $/kW for 1983 operation and 461 $/kW for 1985 operation, and for a plant with $SO_2$ scrubbers, these cost estimates were 533 $/kW for 1983 operation and 535 $/kW for 1985 operation.

The various cost estimates are summarized in the following table:

| | Without $SO_2$ scrubbers | With $SO_2$ scrubbers |
|---|---|---|
| Arthur D. Little Most probable, 3 800-MWe units | 565 $/kW | 697 $/kW |
| CONCEPT, 2 1220-MWe units | 523 | 565 |
| Applicant, 4 650-MWe units 1983/1985 operation | 460/461 | 533/535 |

11.1.10.11 Coal Fuel Cost (MALES-A7)

See Section 9.1.2.2 for staff's discussion of coal fuel cost.

11.1.10.12 Costs of Nuclear Power (YOUNGHEIN-A47)

See Sections 11.1.10.4, 11.1.10.5, 11.1.10.6, 11.1.10.7, 11.1.10.8, and 11.1.10.9.

Reference is made to Table 9.1 which shows the costs of power generation by the two least cost sources; nuclear and coal. Nuclear has a decided cost advantage over coal for this location. Long-term waste storage is not particularly costly. About .2 of the 8.1 mills per kWh nuclear fuel cost in Table 9.1 is attributed to long-term waste storage.

11.1.10.13 Electricity Costs (YOUNGHEIN-A47)

Reference is made to Table 9.1 which shows the staff estimated cost of electricity generation from BFS.

11.1.10.14 Water Sources (PSO-A86)

A comment was made that all water for station use will come from the Oologah Reservoir via the Verdigris River. The water is drawn from the Verdigris River. Only some of the water molecules will come from Oologah Reservoir. Other water will come from tributaries, runoff, rain, potentially from Tulsa sewage effluent, etc., and may not originate in the reservoir.

The water is drawn from the Verdigris River. Only some of the water molecules will come from Oologah Reservoir. Other water will come from tributaries, runoff, rain, potentially from Tulsa sewage effluent, etc., and may originate in the reservoir.

## 11.2 LOCATION OF PRINCIPAL CHANGES IN THE STATEMENT IN RESPONSE TO COMMENTS

| Topic Commented Upon | Section Where Topic Addressed |
|---|---|
| Outdoor Recreation (DOI - A105) | 4.4.4 |
| Historic and Archeological Sites (DOI - A105) | 4.1.1.4 and 4.1.3 |
| Endangered Prairie Chicken (DOI -A106) | Table 2.10 |
| Wastewater Holding Pond (DOI - A106) | 3.6.1.4 |
| Impact on Ground Water (DOI - A106) | 4.1.1.3 |
| Railroad Spur Location (DOI - A106) | 4.4.1 |
| Area Involved in BFS (DOI - A106) | 4.4.3 |
| Grading and Sloping (DOI - A107) | 4.5.2.1 |
| Water Quality Standards (DOI - A107) | 5.5.1.1 |
| Impact on Illinois River (SC - A72) | 3.7.3 and 4.1.3 |
| Dose Assessment (EPA - A101) | 6.1.4 |
| Hurricanes (PSO - A79) | 2.6.3 |
| Industrial Park (PSO - A79) | 2.8.2 |
| Cemetery Location (PSO - A80) | 2.9.1 |
| Plant Water Use (PSO - A80) | 3.3 |
| Sketch of Station (PSO - A80) | Figure 3.1 |
| Schematic of Water Use (PSO - A80) | Figure 3.2 |
| BFS Water Use (PSO - A80) | Table 3.1 |
| Appendix I Evaluation (PSO - A80) | 3.5 |
| Air Ejectors (PSO - A80) | Figure 3.7 |
| Addition of Acid (PSO - A80) | 3.6.1.1 |
| Wastewater Effluent (PSO - A80) | Table 3.6 |
| Waste Discharge (PSO - A81) | 3.6.1.2 and 3.6.1.3 |
| Chemical Additives (PSO - A81) | Table 3.8 |
| Transmission Lines (PSO - A81) | 3.11 |
| Presettling Pond (PSO - A81) | 4.1.1.2 |
| Need for Biologist (PSO - A82) | 4.1.3 |
| Grass Planting (PSO - A82) | 4.3.1.1 |
| Noise Impact (PSO - A82) | 4.4.1 |
| Socio-Economic Impact (PSO - A82) | 4.4.4 |
| Anti-Scalants (PSO - A83) | 5.5.1.1 |
| Chemical Monitoring (PSO - A83) | 5.5.1.2 |
| Trace Element Concentration (PSO - A83) | Table 5.15 |
| Sampling Analyses (PSO - A85) | 6.1.3 |
| PSO Purchased Energy (PSO - A85) | 8.1.2 |
| Energy Costs (PSO - A85) | 8.2.1 |
| Schedule Delays (PSO - A86) | 8.3.1 |
| Reserve Margins (PSO - A86) | Table 8.10 |
| Forecast Load (PSO - A86) | 8.3.1 |

# APPENDIX A

## COMMENTS ON

## DRAFT ENVIRONMENTAL STATEMENT

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UNITED STATES DEPARTMENT OF AGRICULTURE
ECONOMIC RESEARCH SERVICE
WASHINGTON, D.C. 20250

STN 50-556/557 July 20, 1976

SUBJECT: Draft Environmental Statement

TO: William H. Regan, Jr., Chief
Environmental Projects Branch 3
Division of Site Safety and
Environmental Analysis
U. S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, D. C.

We have no comments on the Draft Environmental Statement related to construction of Black Fox Nuclear Generating Station, Units 1 and 2.

VELMAR W. DAVIS
Deputy Director
Environmental Studies

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Advisory Council
On Historic Preservation
1522 K Street N.W.
Washington, D.C. 20005

July 20, 1976

Mr. William H. Regan, Jr., Chief
Environmental Projects Branch 3
Division of Site Safety and
Environmental Analysis
Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Regan:

This is in response to your request of July 15, 1976 for comments on the draft environmental statement (DES) for the Black Fox Nuclear Generating Station, Units 1 and 2, Inola Township, Rogers County, Oklahoma. The Advisory Council notes from its review of the DES that while it appears no properties included in or known to be eligible for inclusion in the National Register of Historic Places will be affected by the proposed undertaking, additional cultural resource studies will be undertaken and the "Procedures for the Protection of Historic and Cultural Properties" (36 C.F.R. Part 800), will be followed as appropriate. Accordingly, we look forward to working with the Nuclear Regulatory Commission pursuant to the procedures as necessary in the future.

Should you have questions or require additional assistance, please contact Michael H. Bureman at P. O. Box 25085, Denver, Colorado 80225. Your continued cooperation is appreciated.

Sincerely yours,

Louis S. Wall
Assistant Director, Office
of Review and Compliance

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*The Council is an independent unit of the Executive Branch of the Federal Government charged by the Act of October 15, 1966 to advise the President and Congress in the field of Historic Preservation.*

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AGRICULTURAL RESEARCH SERVICE — WASHINGTON, D.C. 20250

UNITED STATES DEPARTMENT OF AGRICULTURE

OFFICE OF ADMINISTRATOR

STN-50-556
557

July 27, 1976

Mr. William H. Regan, Jr.
Division of Site Safety and
Environmental Analysis
Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

We have reviewed the Draft Environmental Statement related to the construction of the Black Fox Nuclear Generating Station, Units 1 and 2.

We are concerned over the permanent removal of agricultural land as proposed by the applicant.

We have no comments to add to those recommendations presented by your staff.

Sincerely,

H. L. Barrows
Deputy Assistant Administrator

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UNITED STATES DEPARTMENT OF AGRICULTURE
SOIL CONSERVATION SERVICE
State Office, Stillwater, Oklahoma 74074

July 30, 1976

U.S. Nuclear Regulatory Commission
Att: Director, Division of Site
Safety & Environmental Analysis
Office of Nuclear Reactor Regulation
Washington, D.C. 20555

STN-50-556
557

Dear Sir:

We have no comments on the anticipated environmental effects of the Black Fox nuclear generating station to be located near Inola, Oklahoma. We appreciate the opportunity to review the draft environmental impact statement.

Sincerely,

Roland R. Willis
State Conservationist

RECEIVED 10-10-76 U.S. NUCLEAR REGULATORY COMMISSION

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Docket Nos. STN 50-556
and STN 50-557

25 August 1976



U.S. Nuclear Regulatory Commission
Washington, D.C. 20555
ATTN: Director, Division of Site Safety and Analysis

Dear Director et al:

Pursuant to 10 CFR Part 51 and the Notice of Availability of DES for Black Fox Station Units 1 and 2 soliciting comments from the public, I have some. The focus of my comments is Section 9.1.2.2 and Section 10.3.4.3. which purport to analyze the comparative economics and fuel availability for the Black Fox Nuclear Stations.

Section 9.1.2.2 comprises two paragraphs and is wholly inadequate to the task of determining the economics of a 30-year $8 billion (minimum) economic decision which the Black Fox plants represent. I appreciate the NRC staff's interest in brevity. All that needed to be done was to (a) list assumptions used and the information on which those assumptions are based, and (b) the conclusions that logically follow.

Instead we are told, "in order to generate independent and objective comparative construction-cost estimates, the staff used CONCEPT, a computer program developed and maintained at Oak Ridge National Laboratory." Assumptions are only sketchily presented and no documentation is offered to demonstrate that the assumptions used are in some way connected with the real world.

From what can be deduced, the calculations in Table 9.1 have little to do with the operating experience and costs of similar nuclear installations in the U.S. and are apparently based on someone's opinion of what such experience and costs ought to be, computer programs notwithstanding. Such opinions include:

(a) the assumption that a nuclear plant will obtain 40,000 thermal megawatt days from a ton of enriched uranium fuel (a BWR, in this case),

(b) the apparent assumption that a nuclear plant will operate at the same lifetime capacity factor as the best coal alternative (which is not two 1150-MWe coal plants),

(c) the assumption that a completed nuclear plant will cost $726/kWe in 1984,

(d) the assumption that uranium will escalate in price at only 5%/year,

(e) the assumption that unit costs of a coal and nuclear plant increase linearly as the capacity factor decreases at the same rate,

(f) the assumption that a 10% discount rate and a 12.6% fixed charge rate, including operating and de-commissioning costs, is valid and applies equally to coal and nuclear plants in terms of cost escalation between now and 1984,

(g) the assumption that $30 million will cover all de-commissioning costs, or $13/kWe,

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(h) the assumption that coal and nuclear plants may be assumed to have the same



operating life, and

(i) the assumption that there will be a smoothly and economically-run reprocessing and plutonium recycle program by 1986.

None of these assumptions is warranted by present-day knowledge and no laboratory documentation is offered to demonstrate that such vast improvements will occur by 1984; nor is it shown that even if such improvements in nuclear technology did occur, that they would not be matched or exceeded by improvements in coal technology, or solar or conservation, for that matter.

I don't think economic analysis should be based on fantasy. I don't believe cost estimates should be presented without detailing assumptions involved. Perhaps my concern about the disingenuous NRC staff economics is sharpened by my knowledge that I may be helping to pick up the tab later on.

Since it is difficult to analyse a group of initials, I will try some simple comparisons between NRC staff assumptions and what the nuclear market has to tell us, documented in the attached report on PSO's cost projections, and enumerated below:

1.(a) The NRC staff assumes a capital cost of $1.67 billion for 2300 MWe of nuclear capacity (using only the business power produced), or $726/kWe, for 1984 operation, in 1984 dollars.

(b) We have data from twelve utilities, one reactor manufacturer, and several consulting firms pertaining to nuclear plant capital costs in the 1980's. They are consistent. They range from a low of $880/kWe for a nuclear plant already under construction and scheduled for 1982 operation to an average high of $1,157 for a series of four nuclear plants scheduled for operation between 1982 and 1987. The astounding nature of the NRC staff estimate is that a nuclear plant could not be built today for $726/kWe. The Shoreham, Long Island, nuclear reactor is scheduled to go on line in 1978 at a completed cost of $848/kWe. According to Edward Cowan of the New York Times, "the cost of constructing a nuclear plant has gone from $134 a kilowatt in 1967 to $720 in 1974 and $773 in 1976, according to government and industry data" (17 July 1976). Ebasco Services cites capital costs of $1,135/kWe for a completed nuclear station in the mid-1980's, a good median estimate. Allow PSO a 10% reduction for building two plants on the same site. On what grounds does the NRC staff estimate 1984 capital costs of $726/kWe in the face of overwhelming evidence that the final cost will probably be well over $1,000/kWe?

2.(a) The NRC staff assumes a 10% interest rate and a fixed charge of 12.57% for nuclear costs, including operating and de-commissioning costs.

(b) While PSO's nuclear cost projections may be open to question, we believe PSO should know its own prospects for borrowing money and paying fixed charges. PSO alleges that it will have to pay 7.5% interest (mandated by the state Corporation Commission), provide 11.5% return on equity to investors (borrowing half from each source), pay 7.75% in various taxes, and 0.25% in insurance--a total fixed charge rate of 20%. But that's not all. If operating and de-commissioning charges are included in PSO's projected fixed charge rate as they are in the NRC staff estimate, then PSO's fixed charge is actually more than 23%. Further, the Atomic Energy Commission, in WASH 1174-74, recommends a FCR of not less than 15%. On what grounds, then, does the NRC staff adopt a FCR of only 12.57%, barely more than half PSO's estimate of 23%, including operation and de-commissioning?

3. (a) The NRC staff assumes, in section 10.3.4.2, that Black Fox 1 and 2 would use 11,800 metric tons of raw uranium oxide over 40 years of operation at 80% capacity factor. This works out to more than 40,000 thermal megawatt-days per ton of enriched uranium fuel without reprocessing and more than 30,000 MWtd/mtU with reprocessing, for a boiling-water reactor (BWR).

(b) Major reactor manufacturers now predict, according to the ERDA-33 report, that future BWR's will obtain 25,000 MWtd/mtU. This "guarantee" must be taken in light of present reactor performance, which averages 16,700 MWtd/mtU for all reactors (excluding older inefficient plants); assuming BWR fuel efficiency of 75% that of PWR's, present-day BWR's extract something less than 14,000 MWtd/mtU. ERDA has confirmed the above reactor average (actually, ERDA's estimate for all reactors through 1975 was 14 million kWhe/stU$_3$O$_8$, which works out to less than 12,000 MWtd/mtU). The NRC staff also apparently assumes near-perfect reprocessing and plutonium recycle in the absence of proven, economical technology, NRC licensing, and acceptance of the consequences. Whether the NRC staff has considered a possible increase in ERDA's tails assay from enrichment to 0.37% is not clear. On what grounds does the NRC staff assume a tripling in the fuel efficiency of BWR's from less than 14,000 to more than 40,000 MWtd/mtU? Or, on what grounds does the NRC staff assume both a doubling in BWR fuel efficiency and complete reprocessing of spent fuel with reasonable economy by 1986?

4. (a) The NRC staff assumes both nuclear and coal unit costs rise linearly, at the same rate, as the capacity factor declines.

(b) While it is theoretically possible for a nuclear plant to achieve such fuel flexibility similar to that of a coal plant, in practice maximum fuel efficiency will not be achieved unless the capacity factor and burnup are predicted in advance of fueling the reactor. The fuel cost flexibility projected by the NRC staff won't be realized unless the utility both predicts and achieves the stated nuclear plant capacity factor. Early or late re-fueling will not affect coal plant economics but has been a factor in a large number of nuclear plants now operating. On what grounds does the NRC staff assume the same fuel flexibility for nuclear plants as is assumed for coal plants?

5. (a) The NRC staff apparently believes a nuclear plant will operate at a capacity factor similar to that of the best alternative coal plant and that this



capacity factor will fall in the range of 50-70%.

(b) The NRC staff is surely aware that the present operating performance of nuclear plants 1000-MWe or larger through 1975 was only 44%. Excluding the Brown's Ferry and Trojan plants, the overall c.f. was 52% for large nuclear plants. Assuming (generously) that large nuclear plants will average 50% c.f. in years 1-3 of operation, 65% in years 4-8, 55% in years 9-10, declining steadily to 25% in years 11-30 (as the AEC predicts the final c.f. will be), then the lifetime average would be only 46%. This is not far from the lifetime c.f. projection made by Swedish engineers Peter Margen and Soren Lindhe for all nuclear plants of 42.7%, and operating experience so far indicates large plants run 5%-10% behind the overall average c.f. Large coal plants are not the best alternative to large nuclear plants; a ... plant of 550-MWe to 690-MWe is much more reliable and may be expected to achieve a c.f. in the range of 65-75%. Current operating experience of fossil fuel plants compiled by Edison Electric Institute indicates that all units 390-MWe and larger averaged 64% c.f., but calculation by the Council on Economic Priorities showed these units were base-loaded only 90% of the time and therefore a c.f. of 71% for base-loaded fossil plants could be assumed by extrapolation. All but one nuclear units over 100-MWe in size is base-loaded, and thus no similar extrapolation can be made. Thus the c.f. for fossil units may be expected to be at least 10-15% higher than nuclear units, and medium-sized fossil units 15-30% higher than large nuclear units. If the NRC staff uses similar capacity factors to project coal and nuclear costs--as is apparently the implication of the third sentence in Section 9.1.2.2--on what grounds are such similar capacity factors assumed?

Low nuclear capacity factors to date have resulted largely from poor fuel performance, equipment failures, malfunctions in the cooling systems, material stress and buildup of radioactive crud in the cooling systems of older plants, and so on. Dr. Karl A. Gulbransen, with 25 years of experience in chemical and metallurgical properties of metals and alloys used in nuclear plants and now of the University of Pittsburg's Department of Metallurgical and Materials Engineering, has stated that "there appears to be no way to overcome the inherent material problems associated with zirconium alloys and the current design of the reactor" and that "no backup or alternative design is available." Raising nuclear plant capacity factors and performance may require either extensive reworking of reactor design, adding to capital costs, or costly and frequent repair work as the plant ages to maintain operation, as has already occurred. On what grounds does the NRC staff assume that significant improvements in nuclear plant capacity factors will not occur without large expenditures in light of evidence to the contrary?

Finally, experience with coal plant technology has shown real improvement over the years--a nine-fold improvement in thermal efficiency since 1900, for example. If improvements in nuclear plant capacity factors are assumed to occur, on what grounds is it assumed that equal or greater improvements will not also occur in the capacity



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factors of coal plants?

6. (a) The NRC staff assumes the same lifetime, 30 years, for a coal and nuclear plant.

(b) A 30-year operating life for a nuclear plant is by no means assured. No nuclear plant in the U.S. has been in operation longer than 18 years, no 500-MWe-plus reactor longer than 8 years. Older nuclear plants are suffering severe corrosion, stress, and radioactive buildup in the cooling system; plants older than 12 years operate at a capacity factor averaging 39.2%. While coal plants may require servicing of pollution control equipment, operating experience shows the plant itself will last 40-50 years. Coal plants taken out of service earlier than that were usually retired for reasons of obsolescence, not failure. OG&E currently amortizes coal plants over 40 years, and it is not likely that utilities will retire $750 million to 1.5 billion plants for reasons of obsolescence alone in the future. If a coal plant operates for 45 years, its capital costs in mills/kWhe will be cut by approximately one-third. On what grounds does the NRC staff assume that the operating lives of a coal and nuclear plant will both be 30 years, given the evidence that coal plants historically have lasted longer than 30 years and nuclear operating life has not been established?

7. (a) The NRC staff allows $30 million for de-commissioning costs.

(b) Experience with de-commissioning is sketchy. Mothballing alone for the tiny Saxton plant cost $12.50/kWe, which would be about $26 million for the Black Fox plants. Entombment of the Hallam and Bonus plants averaged $25/kWe, a cost of $57 million for the Black Fox stations. Site restoration for the small Elk River reactor cost $118/kWe, as much as $135 million for the Black Fox plants. Estimates by eight other utilities indicate mothballing costs excluding site surveillance of $6 million average; an average of $30 million for entombment; and around $110 million for site restoration; all for single nuclear plants. Even PSO estimates, along with the AEC, $1 million initial mothballing plus $100,000 monitoring and surveillance (presumably for at least 150 years), but admits "a more probable cost" would be "two to three times higher." It seems the NRC staff estimate, which should at least include mothballing and surveillance for at least 150 years for two large nuclear stations, is distinctly on the low side when compared both to past decommissionings and estimates by other utilities, including PSO's "more probable" projection. A de-commissioning allowance of at least $80 million should be established. On what grounds does the NRC staff make such a low decommissioning estimate?

I do not believe either NRC or PSO's customers, or the state of Oklahoma, should have to run the risk that PSO will not be financially able (or even in existence) 30-150 years in the future to see that appropriate decommissioning and site restoration steps are followed. There is no reason why future generations who will not benefit from the Black Fox plants should be forced to assume responsibility for



the decommissioning. I did not see an NRC staff recommendation that PSO should be required to post bond for the maximum anticipated decommissioning costs. Why was bonding not recommended?

8. (a) The NRC staff escalates nuclear fuel costs at 5%/year.

(b) The cost of uranium paid by utilities has been escalating at more than 100%/year for the past two years. The cost of enrichment will escalate rapidly as ERDA matches commercial rates charged by new private entries into the enrichment business who must profit, pay taxes, and pay commercial electricity rates. Tails assay may rise as high as .37%, increasing uranium feed costs to utilities. Bertram Wolfe, General Manager of Fuel Recovery and Irradiation Products for General Electric Company, judges that reprocessing and storage of spent fuel will cost around $250-$300/kgU by 1985, more than five times present charges. Assuming, as do most business and investor sources, that uranium will cost at least $50-$60/lb. by 1985, enrichment around $140/SWU, reprocessing and storage $250/kgU, with corresponding increases in fuel preparation and fabrication and prevailing fuel carrying charges, the escalation rate will be more than 10%/year. The AEC, in fact, in WASH 1174-74, estimates nuclear fuel cycle costs will escalate at 8%/year--which itself leads to very low fuel projections (ie, uranium at $29/lb. in 1985, compared with Nuclear Fuel Exchange Corporation's estimate of $50/lb. in 1985 on 1975 contracts). PSO as yet has no fuel supply contract. On what grounds does the NRC staff estimate nuclear fuel cycle costs will escalate at an extraordinarily low pace of 5%/year when even the AEC suggests 8%/year, and current market trends indicate that 10%/year will be conservative?

9. (a) The NRC staff projects 1984 coal plant capital costs at $555/kWe, apparently for a plant which "just meets applicable EPA standards."

(b) There is some basis for this judgment since PSO is starting up two coal plants in 1979-80, 450-MWe each, for around $320/kWe base price, $420/kWe with "advanced design" emission controls. At 10%/year escalation, a capital cost of $615/kWe from the latter figure is somewhat higher than NRC's estimate. Capital cost projections made by OG&E ($240/kWe for 1977-78 operation, base price) are similar. Thus the NRC staff estimate seems somewhat low and is perhaps intended to reflect economy of scale inherent in building two 1150-MWe coal plants. But, as pointed out earlier, very large coal plants generally operate at lowered capacity factor and are not the best alternative to nuclear plants. A reasonable estimate would be to assume coal capital costs of $625-650/kWe for a low-sulphur burning station, $750-800/kWe for a high-sulphur station, 650-690-MWe each, 1984 operation, with all applicable pollution controls of advanced design. Technological improvements assumed for nuclear stations should be assumed for coal stations also, unless clearly unwarranted. Further, fixed coal plant charges should be spread over at least 40 years.



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10. (a) The NRC staff assumes a coal fuel cost of 12.6 mills/kWhe for "Wyoming coal delivered to the Tulsa area" in 1976, escalated at 5%/year to yield fuel costs of 18.6 mills/kWhe in 1984.

(b) The NRC staff estimate, in contrast to its projections of nuclear costs, is way too high for coal. The average price of coal in the U.S., including high costs in the East, was only $17.73/ton delivered, according to the Federal Power Commission in late 1975--an average of only 8.8 mills/kWhe in 1975 which a 5% escalation would put at only 9.24 mills/kWhe in 1976. Further, Electrical World's 1975 biannual steam-station cost survey found average coal plant costs outside the Northeast totaling only 13.8 mills/kWhe busbar. If the NRC staff estimate, discounted 5% to 12 mills/kWhe, for coal fuel alone is in any way accurate, then these plants must have cost nearly nothing to construct and operate. Finally, we have a contract price statement from Oklahoma Gas & Electric Company for Wyoming coal delivered to northern Oklahoma--$15/ton, or approximately 7.5 mills/kWhe (assuming 9,500 BTU/lb. coal and 9,500 BTU/kWhe in coal plants), for 1977 delivery. Escalated at NRC's suggested 5%/year rate, the cost would be only 10.6 mills/kWhe in 1984. No sources in government or industry we've seen expect the price of coal to escalate rapidly in the future (including FEA, President's Council on Wage and Price Stability, Investor Responsibility Research Center, Mitre Corporation, etc.). Nevertheless, even assumption of a high 8%/year rise in the cost of coal at the mine, 10%/year increase in transportation costs, and a 16% fuel carrying charge would mean 1984 coal costs of only $30.27/ton, using OG&E's contract as a base. This would be a fuel cost of only around 15.1 mills/kWhe using high escalation rates. On what grounds does the NRC staff assume a 1976 Oklahoma coal fuel cost of 12.6 mills/kWhe when the state's largest utility has a 1977 contract price of only $15/ton delivered (7.5 mills/kWhe, approximately), and the average 1975 price for the whole nation was only $17.73/ton delivered (8.8 mills/kWhe)? (In fact, 1975 coal prices in Texas were only $3.41/ton, according to the FPC, and the western U.S. has much lower coal prices than the East). On what grounds does the NRC staff and its computer project a coal plant fuel cost of 18.6 mills/kWhe in 1984 when even a high rate of cost escalation would yield only around 15 mills/kWhe for Oklahoma utilities?

A run through any number of calculations will show than no reasonable combination of cost assumptions will yield lower costs for a 1984 nuclear plant than for a 1984 coal plant built in northeastern Oklahoma. In fact, making only two adjustments in the NRC staff's cost assumptions--using PSO's fixed charge rate of 20% instead of NRC's 10%, and substituting OG&E's coal price projection for the NRC's, escalated at 5%--and leaving all other assumptions intact, yields 1984 coal generation unit costs 9% lower than corresponding nuclear generation costs. Using reasonable assumptions for coal plant ($650/kWe capital costs for a plant which meets EPA standards, $30/ton fuel costs, 70% lifetime capacity factor, 20% FCR for 30 years, 40-year plant life



and 3 mills/kWhe operating costs) and a large nuclear plant ($1,000/kWe capital costs, 10 mills/kWhe fuel costs, 50% lifetime capacity factor, 20% FCR, 30-year plant life, and 3 mills/kWhe operating costs) yields 1984 coal plant unit costs 43% lower than nuclear plant costs--even assuming reprocessing of spent nuclear fuel--for approximately 10.074 billion kWhe generated per year. This margin should probably be considered conservative since nuclear costs, both capital and fuel cycle, are currently much more unstable than coal prices and can be expected to escalate much more rapidly.

We suggest a hard look at coal and nuclear technology as they actually operate today, and as they may reasonably be expected to be applied commercially two to ten years down the road. Oklahoma Gas & Electric Company has also examined the coal/nuclear alternatives and found low-sulphur coal "far and away the best solution," according to its president, James Harlow. Medium-sized coal plants present a much more flexible choice than do large nuclear plants for a future in which electricity demand promises to be uncertain--assuming the added capacity is needed at all.

The NRC staff estimates do not represent the kind of careful, conservative, realistic economic analysis PSO's customers have the right to expect from a public agency regarding an $8 billion-plus decision spanning thirty to 200 years into the future. Two paragraphs and the initials of a computer program are not adequate to justify a doubling of a medium-sized utility's capitalization in one stroke, when its customers will pick up the tab. I hope the final Environmental Statement reflects a more realistic economic examination of the Black Fox plants and alternatives.

A second issue involves the NRC staff's inadequate examination of conservation alternatives. If PSO's projections for the rise in electricity rates is correct (39% by 1980, 75% by 1985), then historical price elasticity established elsewhere in the country predicts a slowing (and perhaps even reversal) of growth in electricity consumption in PSO's service area. Conservation programs such as those undertaken in Los Angeles and Seattle, and currently being implemented for Oklahoma state institutions and various industries, can reduce demand even more with no economic or social penalties. The brief conservation analysis in the accompanying report (pp 48-52) indicates that PSO's coal plant additions already scheduled for 1979-80 should be more than enough capacity for the forseeable future even without planned conservation.

Finally, we don't believe the NRC staff's estimation of domestic and foreign uranium supplies, even though more detailed, is adequate. Too much reliance is placed on ERDA's preliminary NURE estimates for which ERDA admits no confidence parameters have been established and on sketchy and incomplete resource projection by means of geological analogy. Dr. M. King Hubbert, geophysicist with the U.S.G.S. and perhaps the nation's foremost expert on energy resources, has testified that geological analogy projections can yield "large overestimates." Hubbert and others use comparisons of resource discoveries per foot of drilling which have been historically more accurate and are widely used in industry today. They conclude that sufficient recoverable uranium does not exist to fuel a large nuclear program; in terms of the Black Fox plants, perhaps as much as half their uranium fuel will have to come from very low grade sources which in all probability will not be econo[illegible]ally exploitable. Foreign uranium supplies are very questionable and the effects of even early introduction of the breeder likely to be negligible. We suggest that NRC's staff examine the projections made by resource evaluation authorities such as Hubbert, M.A. Lieberman, M[illegible]rgan Huntington of the U.S. Bureau of Mines, Hans Alder of ERDA, and M.C. Day of Louisiana State University, and include them in t[illegible] final statement.

Documentation and detailed discussion of uranium su[illegible]plies, conservation, and the economics of the Black Fox plants and its alternatives are included in the accompanying report, which should be considered as part of my co[illegible] on the NRC staff's Draf[illegible] Environmental Statement.

I thank the NRC staff for its attention to these comments and hope they will aid in preparation of a more complete and realistic Final Environmental Statement.

Sincerely,

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ANALYSIS OF PUBLIC SERVICE COMPANY'S

PROJECTIONS FOR BLACK FOX NUCLEAR STATIONS

By Mike A. Males, Oklahoma City
Marvin Cooke, Tulsa
22 August 1976

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22 August 1976

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# ANALYSIS OF PUBLIC SERVICE COMPANY'S PROJECTIONS FOR BLACK FOX NUCLEAR STATIONS

## A. SUMMARY AND CONCLUSIONS

In 1978 Public Service Company of Oklahoma (PSO) plans to begin construction on two 1150-megawatt boiling-water nuclear generating stations to be located 25 miles from downtown Tulsa. Approximately 61% of the Black Fox plants will be owned by PSO, while the remainder will go to Associated Electric Co-operative of Missouri, PSO's partner in the project, and other utilities which subscribe.

Once begun, the construction of these plants will represent an irreversible commitment to the economics of nuclear power, a commitment whose gravity may be judged by the following comparison:

> PSO's share of the two Black Fox plants is estimated to be well over $900,000,000. In 1975 PSO's entire capital assets--including all its generating plants, transmission lines, distribution network, buildings, property, and construction work in progress--amounted to only $574,746,980.

If PSO's cost estimates are accurate, the two plants will supply 260 billion kilowatt-hours of electricity (kWhe)* to the PSO service area over their 30-year lifetimes at a total construction and operation cost of slightly less than 3¢/kWhe--$7.8 billion in all. Depending on the rate of population growth in PSO's service area, the average residential/commercial/industrial electricity customer will pay $10,000-$15,000 (1985 dollars) for the Black Fox plants alone.[1]

We have carefully examined the economic projections contained in PSO's massive Environmental Report (ER) on the Black Fox plants. Our conclusions regarding the validity of PSO's projections are as follows:

- PSO's cost analysis differs radically from other recent nuclear studies, including projections made by business investor reports, the Atomic Energy Commission and its successor Nuclear Regulatory Commission, and other utilities planning similar-sized nuclear plants for the early 1980's.**
- PSO has drastically underestimated the capital costs of the Black Fox plants --in fact, a nuclear plant could not be built today for the price PSO projects for 1984.
- PSO has greatly overestimated the amount of electricity Black Fox 1 and 2 will produce by assuming they will generate 80% of the power they are capable of generating. Nuclear plant experience to date shows an average capacity factor of only 55% and large plants of the type PSO plans to order operating in the 4[illegible]% range. Not one nuclear plant in the country has consistently operated at 80% of capacity, and Atomic Energy Commission studies now suggest using capacity factor projections of 57-65%.

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* A kilowatt equals 1,000 watts, and a kilowatt-hour is a measure of electricity equal to the continuous generation of one kilowatt for one hour.

** The Atomic Energy Commission (AEC) was recently abolished and its functions split between the Nuclear Regulatory Commission (NRC) and the Energy Research and Development Administration (ERDA). Some AEC data remains the most current on its subject.

. PSO has understated the fuel needs of Black Fox 1 and 2. PSO projects a power yield of over 50,000 thermal megawatt-days/ton of enriched uranium, far in excess of even optimistic nuclear industry projections of future reactor yield (25,000 MW(t)d/ton), to say nothing of reactor operating experience (16,700 MW(t)d/ton).*

. Assumptions of readily available uranium supplies are clouded by many authoritative surveys of domestic resources which forecast shortages instead--including those done by ERDA, the General Accounting Office, U.S. Bureau of Mines engineers, the U.S. Geological Survey, major investment firms, and independent geologists. Uranium supply after 1990 is very uncertain.

. Future electricity demand projected by PSO to justify the need for Black Fox 1 and 2 may be unreasonably high. Conservation measures already undertaken by private and governmental electricity consumers elsewhere in the nation--and in the Tulsa area--indicate a decline in electricity consumption and an overall slowing in the rate of growth. The primary reason for increased energy conservation seems to be rising price.

. Overall cost projections for the Black Fox plants, using the most recent data available and conservative assumptions, will be in excess of 6¢/kWhe, more than twice the cost originally forecast by PSO. Based on economic judgments alone, virtually any energy alternative--including conservation programs, coal-fired generating plants, and solar installations--will be preferable in the long run to building the Black Fox plants, barring unprecedented breakthroughs in nuclear technology.

. Construction of medium-sized coal-fired stations in place of the Black Fox reactors will provide greater flexibility, create more jobs, and generate power 20-35% cheaper than would nuclear stations. Comprehensive efforts to reduce peak and total electricity demand will yield even greater savings.

We believe the large divergence between our conclusions and PSO's are attributable to several factors. The major problem in analyzing PSO's Environmental Report has been PSO's failure to identify all of the assumptions used in projecting costs, but those assumptions that are presented indicate use of outdated information:

. The data used by PSO is apparently from 1972 and 1973. Both the AEC and private industry sources have raised nuclear cost estimates substantially in recent years. The AEC, in fact, has raised nuclear capital projections 500% since 1968. PSO has not revised its estimates.

. PSO assumes annual cost escalation of 5%. Nuclear construction costs have actually been increasing at a 15%/year rate since 1965, and industry sources see no end in sight. Cost increases for coal-fired plants have been much less dramatic, averaging under 10%/year.

. PSO's estimates on how well the Black Fox plants will perform are much more optimistic than operating experience of nuclear plants would justify and even exceed maximum industry projections for improvements in reactor operation.

The cost projections made by PSO and conclusions reached in this report regarding the Black Fox stations are summarized in Table 1. The derivations of our cost estimates are outlined in the remainder of this report.

We strongly suggest that PSO's customers carefully examine both PSO's Environmental

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* A megawatt equals 1,000 kilowatts and may measure either heat (thermal) or electricity. It takes around 3 megawatts of heat to produce one megawatt of electricity in reactors.



TABLE 1

COMPARATIVE COST PROJECTIONS

| COST ITEM (1985 DOLLARS) | PSO'S [illegible]JECTION* | OUR PROJECTION |
|---|---|---|
| Capital costs, two 1150-MWe nuclear stations** | $1.545 billion | $2.346 billion |
| - per kilowatt of capacity | $672 | $1,020 |
| - fixed charges on debt | 20% | 20% |
| - in mills/kWhe, levelized over 30 years | 18.4 | 44.7 |
| Decommissioning costs | $1 million plus $100,000/year indefinitely | $47.5 million |
| - in mills/kWhe, levelized over 30 years at 20% fixed charge | 0 | 0.9 |
| Operating and Maintenance charges, in mills/kWhe, levelized over 30 years | 2.7 | 2.7 |
| Nuclear fuel cycle costs, in mills/kWhe, levelized over 30 years (including reprocessing credits)*** | | |
| - mining and milling, $U_3O_8$ | (does not itemize) | 3.4 |
| - conversion to $UF_6$ | | 0.1 |
| - enrichment | | 2.5 |
| - fuel preparation and fabrication | | 0.6 |
| - reprocessing and storage | | 1.2 |
| - carrying charge, 16% | | 3.3 |
| - total fuel costs | 5.1 | 11.1 |
| Other costs | 3.1 | 3.1 |
| TOTAL COSTS, IN MILLS/kWhe, LEVELIZED OVER 30 YEARS | 29.2 | 62.5 |
| REACTOR PERFORMANCE ASSUMPTIONS | | |
| Expected operating life | 30 years | 30 years |
| Capacity factor, 30-year average | 80% | 55% |
| Total kWhe generated/year, 30-year average** | 16,118.4 million | 11,081.4 million |
| Power yield, in thermal megawatt-days/metric ton of fuel, 30-year average | 50,350 | 25,000 |

* From Environmental Report (ER). Costs for two Black Fox plants are averaged.
** The Black Fox plants are actually 1220-MWe in size, but 70 MWe is for use on-site and thus is not available for sale. Both PSO's and our cost estimates above account for this by using only the salable capacity, 1150-MWe.
*** PSO's fuel cost estimate assumes a plutonium recycle credit; ours does not, since feasibility is not proven and licensing not granted. Those who believe in ultimate transition to plutonium recycle may subtract 1.3 mills/kWhe credit from our estimate. Both estimates include $U_{235}$ reprocessing from spent fuel.



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Report (available at the Tulsa main library) and this report and demand re-evaluation of electricity costs and power demand from PSO. In the last 24 months utilities across the country have carried out just such re-evaluations and, according to Business Week, "have cancelled or delayed some 190,000 Mw of generating capacity. ,of which 130,000 was nuclear--the equivalent of about 130 large plants."[2] Reactor manufacturers received only four new domestic orders in 1975 and none in the first quarter of 1976. If re-evaluation of the Black Fox plants based on realistic cost assumptions is not done now, the economic life of the Tulsa region may be disrupted and promising energy alternatives lost.

B. NUCLEAR ECONOMICS

(1) Capital Costs

> The unwillingness of nuclear engineering companies to promise delivery of a $1 billion to $1.5 billion plant six or seven years in advance for a fixed price is symptomatic of the runaway economics--an unanticipated surge of capital, labor, and uranium costs--and other shocks that have buffeted the nuclear power industry in the last few years.
> - Edward Cowan, New York Times energy and economics specialist[3]

> A number of federal energy officials and independent energy analysts wonder today whether electricity generated with nuclear power might be priced out of the market by rapidly rising construction costs and uncertainties surrounding the price and long-range supply of uranium fuel.
> - Robert Gillette, nuclear staff expert for Science magazine[4]

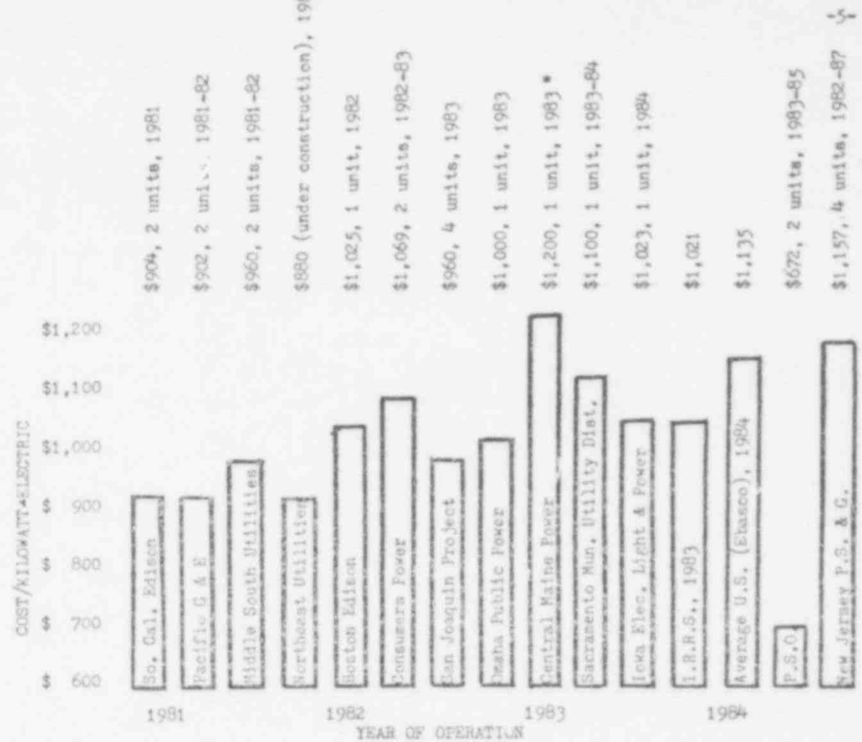
> We need all the electricity we can get in Iowa. But there are monumental unanswered questions in the economics of nuclear generation. There are literally no answers. Until we can get them, our commission will do what it can to prevent any company from investing in a nuclear plant.
> - Martin Van Nostrand, Chairman, Iowa Public Utility Commission[4]

PSO has estimated, in its Environmental Report and subsequent statements as recently as 30 June 1976, that the two Black Fox stations will cost a total of $1.545 billion, or $672 per kilowatt of capacity for 2,300,000 kilowatts (2,300 megawatts), excluding land acquisition costs.

PSO has apparently not revised its cost data in several years. A nuclear plant could not be built today for that price. The industry-wide average for nuclear capital costs in 1976 was $773/kWe.[5] Ebasco Services, the nation's leading reactor engineering firm, predicts capital costs of $1,135/kWe by 1984. Graphic comparison between PSO's projection and those made by leading utilities and business sources is offered in Figure 1.

Many utilities had made projections similar to PSO's in the early 1970's. Long Island Lighting, for example, originally forecast its 819-MWe plant at $278/kWe; current costs are pegged at $848/kWe, operation to commence in 1978. Sacramento Municipal Utility District estimated $722/kWe for an 1100-MWe addition to its Rancho Seco nuclear unit, but a 1976 revision brought that price up to $1,100/kWe. Consumers Power of Michigan






*Central Maine Power estimate includes first fuel core.

COMPARISON OF PSO'S NUCLEAR CAPITAL COST FORECAST WITH THOSE MADE BY OTHER INDUSTRY SOURCES[6]

FIGURE 1

made three escalating projections in 1975, the last one at $1,069/kWe for its two planned nuclear units. Atomic Energy Commission estimates for nuclear capital costs are five times as high in 1974 as in 1967, and still behind the times.[7]

The above estimates are by no means pessimistic. Lewis Perl, one of the nation's leading utility consultants, told the Atomic Industrial Forum in late 1974 that "the costs of nuclear plants appear to be escalating at a rate of 15 percent per annum and the costs of fossil plants at a rate of 10 percent."[8] If unabated, 1985 nuclear costs would be over $1,700/kWe. Bank of America similarly predicted that per-kilowatt costs for nuclear plants now planned could be as high as $1,907. Likewise Rand Corporation.

There is little reason to believe nuclear capital costs will radically slow down or reverse their rapid escalation rate in the near term. In fact, there are many reasons to believe they may escalate as fast or faster. The principle causes of cost increases in recent years remain unresolved and may well be inherent in the nature of nuclear technology:

(1) Delays in construction. The long, ten-year lead time between planning and operation of nuclear reactors is often blamed on public opposition and federal regulatory foot-dragging. In reality, virtually all of the delays to date are attributable to administrative and management problems within the nuclear industry and utilities themselves. A recent study by the Federal Power Commission found only 32 plant-months of delay caused by federal regulatory changes or citizen lawsuits, compared with 229 plant-months of delay due to such management shortfalls as late equipment delivery, poor labor productivity, labor shortages, equipment failure, and rescheduling of related facilities.[9] Less than 5% of the delay in reactor construction is the result of citizen action, and utility executives surveyed by business publications unanimously cited economics rather than public opposition as the primary reason for deferring nuclear plants.[10]

(2) Design changes. Safety- and efficiency-related design changes have sharply increased the costs of nuclear plants due to the experimental nature of nuclear technology. While expensive, design evolution is essential if nuclear technology is to be, in the words of nuclear proponent Dr. Hans Bethe, "not static but. . .a developing art." Another vigorous nuclear advocate, H. Peter Metzger, observes:

> Those on both sides of the nuclear issue agreed that delays in the construction of nuclear reactors imposed by environmental considerations were well worth the improvements that finally were built into the new nuclear technology.[11]

Many reactor design changes remain to be implemented, however:

(a) The federal NRC has pinpointed 27 areas where safety design will have to be reworked on a priority basis. NRC staff documents list an additional 183 unresolved safety problems identified as under study and 44 more tabled for the moment because of "manpower limitations or information is not available." Included for study are such major components as steam tube rupture, pressure vessel failure during steam explosions, and turbine flywheel malfunctions which could breach reactor containment.[12]

(b) Major design changes will follow the NRC's review of last years $200 million Brown's Ferry reactor fire in Alabama, which the NRC called "the worst accident in light-water reactor history." The Brown's Ferry plant superintendent testified that the reactor "lost redundant components that we didn't think we could lose" during the hours-long cable fire. William Anders, then chairman of the NRC, stated that remedial actions for existing and future reactors would involve "massive costs."[13] De-centralization of reactor cable networks and other modifications are expected to cost at least $100 million per reactor for existing plants; perhaps as much as $16 billion overall.

(c) Boiling-water reactors, the kind PSO plans to order, are particularly in line for design changes which will increase cost. In the fall of 1974 all 21 boiling-water reactors in the United States had to be shut down for inspection, and several suffered prolonged outage for repairs to cracked cooling pipes. Vibrations in traversing in-core probes remain a serious problem which may force organic re-design.

(d) Reactor performance, in terms of fuel consumption, reliability, and forced outage, has been poor. Improvements must be made if nuclear power is to expand. Reliability problems are discussed in a later section.

(3) The nuclear industry. The whole atomic industry is, in the words of Harvard Business School Professor Irvin C. Bupp, "in a bucket of trouble." It is difficult to find experts who don't agree with that assessment. Differing reasons are offered within the business community for the nuclear "malaise:"

(a) The harshest criticism is leveled by the nation's second largest investment consulting firm, Mitchell Hutchins of New York. Rejecting claims that nuclear troubles are the result of influences beyond the industry's control, Mitchell Hutchins advised its clients of severe internal problems:

> As one might expect, poor management lies behind this series of technological failures. The managerial shortcomings are on two levels--competency and honesty--neither of which is consistent with the trust the public now places in this industry for 8% of the electricity produced in the nation and the bulk of mid-term energy growth. . .the nuclear industry has broken faith with the public over and over again, in its presumed technological and managerial competence.[14]

Both the management-related delays described earlier and the current legal difficulties of the nuclear industry support the Mitchell Hutchins conclusions. Westinghouse recently defaulted on $1.9 billion worth of nuclear fuel promised to utilities as part of reactor contracts, claiming inability to produce the fuel at the contract price. Sixteen utilities are suing Westinghouse, with nuclear fuel costs certain to rise no matter which side wins. Westinghouse's main competitor, General Electric (together they control 70% of all reactor sales), is faced with a similar fuel shortfall but has not yet defaulted. General Electric recently settled a $62.8 million lawsuit with Jersey Power and Light, in which the latter alleged cost overruns and delays, and was promptly slapped with another suit, this time for $125 million by Nebraska Public Power District alleging negligence and failure of key reactor systems, settlement pending. General Electric is also currently defending in two lawsuits filed by eleven New England utilities seeking $300 million from G.E. for alleged breach of fuel reprocessing contracts.[15] A majority of the nation's utilities operating nuclear plants are engaged in legal action against reactor and fuel suppliers.

(b) General Atomic's president, Richard McCormack, blamed the public/private dichotomy of the nuclear industry in explaining his firm's decision to drop out of the reactor field altogether:

> The fundamental cause of our malaise is the nature of the nuclear business itself. It was born in the government and consciously weaned by statutory and administrative policies to grow through an adolescence of government support. But the business was never firmly founded, and the magnitude of the problems of getting it established in the private sector were never fully appreciated.

"Frankly," McCormack concluded, referring to all atomic enterprises, "we are a sick industry."[16] The financial trouble of the atomic industry is not altogether justifiable in light of the $8 billion in federal money poured directly into reactor research (not counting the government research on nuclear weapons which benefited the reactor program) --more than 1.5 cents for each of the 500 billion kilowatt-hours generated from nuclear plants in the 1957-75 period. This federal subsidy far exceeds that given to other energy sources, and nuclear power continues to receive more research funding than all other fuels combined, as well as federal insurance, uranium enrichment, and fuel reprocessing aid. A sick industry, especially one which has received so much public doctoring, is not likely to be handing out bargains in the near future.

(c) Of the five (now four) major reactor manufacturing firms in the United States, only Westinghouse is now turning a profit from its atomic enterprises. Some of the reason for this is the fierce competition for reactor sales in the 1960's and early 1970's which led reactor manufacturers to offer nuclear plants and attractive fuel packages at below market price to utilities seeking to "go nuclear." Reactor manufacturers lost hundreds of millions of dollars on these "loss leaders" designed to stimulate reactor sales and may lose billions more (especially Westinghouse) to adverse court judgments stemming from default on uranium supply and reprocessing contracts. General Electric's 1972 annual report explains why a manufacturer would take such immense risks: "our potential revenue base in a nuclear plant, for example, is some six times that of a fossil plant because we can supply the reactor, the fuel, and fuel reloads as well as turbine generators and their auxilliary equipment." While "loss leader" reactor sales have provided nuclear-generated electricity to consumers at artificially low prices, courtesy of reactor manufacturers, these losses will now have to be made up and future reactor sales made at market price. These factors will stimulate the increase in nuclear plant capital costs, as will the general financial distress of the nuclear industry.

The features of the nuclear industry and nuclear technology itself do not predict a slowdown in spiraling nuclear capital costs. A joint Harvard School of Business Administration/Massachusetts Institute of Technology study concluded, "The capital costs of large light-water reactors show no signs of stabilizing and indeed, are apparently still climbing at alarming rates."[17]

Both the Atomic Energy Commission and a Washington-based consulting firm, Investor Responsibility Research Center, suggest base cost estimates of a 1000-MWe nuclear plant of $433-520/kWe, escalating 8%/year during an 8-year construction period, beginning in 1975. The IRRC study found much of the AEC data relating to interest rates and cost escalation outdated, but nevertheless adopted some of the AEC assumptions and calculated a 1982 capital cost of $811/kWe assuming a 10% interest rate--figures which today appear too conservative. The IRRC, in fact, concluded, "the cost of nuclear power plants has been increasing at more than 8 per cent per annum."[18] These conservative projections, however, still yield costs in the range of $880-1040/kWe for 1984.



Even PSO, in its "Memorandum of Understanding" with Associated Electric Co-operative of Missouri, notes that "industry projections for a completed nuclear station, scheduled for operation in 1983, may exceed eight hundred dollars ($800) per kilowatt depending on inflationary pressures on labor, materials, and components, and the evolving standards and requirements" of licensing.[19] PSO does not use these "industry projections" to calculate actual Black Fox costs, however, in its economic assessment.

Although we believe the costs of a nuclear station completed in 1983-85 could easily exceed $1,135/kWe, the average cited by reactor engineering firm Ebasco Services, we have estimated $1,020/kWe for purposes of this study, or a total cost for Black Fox 1 and 2 of $2,346 billion. We assume that PSO's costs will be about 5% less than those for single plants because PSO plans to build two plants on the same site. And we assume--very optimistically--that the surge in reactor prices which has been fairly consistent since 1965 will slow down from 15%/year to 8%/year.*

(2) Decommissioning

At the end of its operating life a nuclear plant must be de-commissioned in a special way so that its radioactive components do not contaminate the surrounding area. Decommissioning a large nuclear plant is a complicated process. Years of neutron bombardment have made interior components of the reactor highly radioactive, increasing the hazards to plant workers and surrounding populations as the plant ages. Present-day experience with de-commissioning small reactors is sketchy and suggests ultimate costs will be much greater than anyone now predicts.

PSO apparently plans to "mothball" the two Black Fox plants in the year 2015, which consists of the following (as listed in the Environmental Report):

- Deactivation of the reactor.
- Removal and disposal of wastes of the type normally discharged during operation.
- Decontamination of process systems in appropriate areas of the station.
- Removal of all nuclear fuel, control rods, and other reactor internals from the site. . .
- Sealing of buildings or portions of buildings which contain contaminated process piping or components.
- Maintaining necessary security measures and systems such as fire detection and protection systems and ground water intrusion detection systems.
- Surveillance and periodic maintenance of the protective measures for the duration of the "mothballed" state to prevent degradation thereby assuring the protection of the health and safety of the public (sic).[20]

The duration of the mothballed state is estimated by the AEC and NRC to be 150-180 years. Thus the two Black Fox hulks will remain for generations as features of the Inola landscape, posing danger of radiation leakage well into the 22nd Century, at which time they would presumably be dismantled and the site restored.

* N.B.: These estimates are very conservative. A straight 8%/year escalation would work out to costs of more than $1,400/kWe by 1984, which is not inconceivable. Upward cost revisions by [illegible]ies and industry analysts may not have run their course.

PSO estimates the cost for this type of de-commissioning at $1 million initial expense plus $100,000/year for surveillance and monitoring (presumably for 150 years), or $16 million total de-commissioning costs--but admits "a more probable cost" would be "two to three times higher."[20] As with capital costs, PSO does not use its own estimate of the "more probable cost" in its economic analysis of Black Fox 1 and 2.

No one really seems to know what de-commissioning will cost. Entombment of two small nuclear plants in the late 1960's cost $17.50/kWe and $32.24/kWe respectively, which would be $50-90 million for the Black Fox plants in 1985 dollars. Site restoration for another tiny nuclear plant completed in 1972 cost nearly $120/kWe. Estimates for future de-commissioning of larger nuclear plants made by utilities indicate an average initial cost of $6 million plus maintenance and monitoring costs; $21-45 million for entombment; $90-128.5 million for site restoration.[21] An engineer who worked on the de-commissioning of the Peach Bottom 1 reactor estimates that full dismantling and site restoration will be equal to or larger than the original capital cost of the nuclear steam supply system, perhaps $80-300/kWe, $900 million to $3.4 billion for the Black Fox plants.[22]

There is also disagreement over how long a surveillance period is required before the sealed plant may be safely entered and dismantled. The AEC, as noted, suggests 180 years, which means the great-great-great-great grandchildren of the builders of the nuclear plant would see it to its final resting place. But Dr. Marvin Reskinoff, a high-energy physicist with New York's Public Interest Research Group, pointed out that the radionuclide nickel-59 remains hazardous for 1.5 million years, rendering simple dismantling procedures impossible.[23]

What PSO's financial condition will be in 150, or 1.5 million, years will require something more than accounting principles to predict. Bonding should be required to assure that the costs of de-commissioning the Black Fox plants will be paid by those who benefit from the electricity they produce--not future generations who will inhabit the Tulsa area in the 23rd Century. Dollar costs are not the issue here. Realistically, however, we use PSO's "more probable" estimate at a fixed charge of 20%--around $45-50 million total, $9-10 million per year, or a levelized cost of 0.9 mills/kWhe, for de-commissioning allowances.*

(3) Fixed Charges

PSO calculates fixed charges on the Black Fox plants--the percentage of total capital which must be paid each year regardless of plant output--at 20%. The Environmental Report breaks down the fixed charges:

* A mill equals one-tenth of a cent, or $0.001.

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| | | |
|---|---|---|
| Interest on debt | 3.75% | $ 58.1 million/year |
| Return on equity | 5.25 | 81.3 |
| Income tax | 5.25 | 81.3 |
| Depreciation | 3.00 | 46.4 |
| Property tax | 2.50 | 38.7 |
| Insurance | 0.25 | 3.8 |
| TOTAL | 20.00% | $309.6 million/year |

PSO's share of the Black Fox plants is around 61%. PSO's partner in the Black Fox project, Associated Electric Co-operative of Missouri, is a rural electric co-operative and elegible for low-interest federal loans and guarantees. The potential benefits of this arrangement are explained in the "Memorandum of Understanding:"

> If PSO becomes financially unable to complete construction of the Station, Associated, at its sole election, shall have the right to finance the completion of the Station. PSO will repay all costs of Associated in obtaining such financing as soon as it is possible for PSO to do so.

What the federal government decides to do seems to be the key element in all planning about nuclear power. David Dinsmore Comey, environmental director for the Chicago-based Businessmen for the Public Interest and a nuclear economics critic, described the problem at a recent Federal Energy Administration hearing:

> The annual requirements for new capital for the entire electric utility industry have recently bounced from $5 billion to roughly $10 billion, and the industry is having grave difficulties raising even these sums. . .only the U.S. Government is likely to be available for these capital requirements. . .[24]

A Federal Energy Administration task force comprised of industry, government, and academic representatives concluded that utilities would need at least $650 billion for construction between now and 1939, assuming moderate growth and inflation--four times today's total utility worth and 35% of the capital market.[25] What such immense capital requirements will do to interest rates is not predictable, but massive federal help for utilities is the often-proposed answer. But the federal government may be reluctant to underwrite further nuclear ventures if nuclear costs don't stabilize soon and if alternative energy sources become correspondingly more attractive. And the enormous federal drain on capital supply which will be necessary to significantly aid utility and nuclear construction may do more damage to other industries seeking to raise capital than the benefits for the utility industry would offset.

(4) Insurance Economics

The catastrophic accident risk factor in nuclear energy--whatever its probability--is now largely born by the public, not industry, due to federal intervention. The federal government now provides insurance to the nuclear industry and utilities at one-sixth the cost of the lowest premium charged by private insurers and exempts the nuclear industry from damage claims totaling in excess of around $600 million. Nuclear insurance costs seem destined to rise rapidly as the burden is shifted to utilities and industry, although the liability limit will still mean that residents living in the vicinity of the

Black Fox plants may be legally denied all but a fraction of the compensation due them in the event of an accident. Joseph Marrone, General Counsel of the Nuclear Energy Liability-Property Insurance Association, declared the need for more direct insurance pricing:

> It is time for private industry to substantially increase its share of the responsibility for financial protection of the public so that the nuclear industry, the financial community, and insurers can plan accordingly.[26]

(5) Capacity Factors

The "capacity factor" of a power plant refers to the number of kilowatt-hours the plant produces divided by the number of kilowatt-hours it could produce if operating 100% of the time at full power, expressed as a percentage. While the NRC has confused calculations somewhat by using extraneous indices such as "availability factor," "reliability factor," and "maximum dependable capacity," the capacity factor is all that counts from an economic point of view because it measures the plant's total electricity production as a percentage of the size (and therefore cost) of the plant.

Louis J. Roddis Jr., president of Consolidated Edison Company of New York during its nuclear development phase, stated, "most, if not all, of the economic studies that led utilities to go nuclear were based on assumed energy deliverability of 80% or more."[27] PSO's study, as founded in the Environmental Report, is no exception:

> All costs are based on station operation at 80 per cent capacity factor.[28]

Previous cost-benefit analyses by the AEC for 20 nuclear plants based all projections on assumed capacity factors of 80%. Recently, however, the AEC took a sober look at the actual performance of nuclear plants and revised its estimate downward to 65.2%, even suggesting that a lifetime capacity factor of 57.4% was all that could be expected.[29]

As might be expected, the capacity factors of nuclear plants to date has been worse still. NRC data listed net annual capacity factors of all operating commercial nuclear plants as 58.8% average in 1973. In 1974 the net annual average dropped to 52.8%. In 1975 it was 54.8%.[30] The cumulative average to date is 54.3%.

Large nuclear plants fared even worse. Nuclear reactors 1000-MW or larger (the Black Fox plants are planned at 1150-MW) produced only 46% of the electricity they were designed to generate in 1974, 44.5% in 1975, 36.4% in the first quarter of 1976.[30]

The economic benefits of a new, large nuclear plant disintegrate as the capacity factor drops. Between seventy and seventy-five percent of the costs of the Black Fox plants are fixed--that is, they do not vary with output and must be paid regardless of the amount of electricity the plant produces. Coal-fired plants, whose costs are closely tied to the costs of fuel rather than capital, are much more flexible in this regard.

What, then, is the reason for poor nuclear plant performance to date? Will it improve in the future? The answers are not encouraging. All but one of the 100-MW or larger



nuclear plants operating today are "base-loaded," while fossil-fuel plants may be operated only during times of peak electricity demand. The reasons are obvious. A nuclear plant requires a larger capital investment but promises lower fuel costs than do fossil-fuel plants so that utilities are motivated to operate nuclear plants as much as possible to recover capital investment and save on fuel costs. Shutdown of a nuclear plant is difficult and costly, requiring weeks to months of plant loss. Thus utilities are reluctant to remove a nuclear plant from service unless it is absolutely necessary. Disappointingly low capacity factors reflect organic design weaknesses which may be improved only with costly technological changes.

Not one of the 56 commercially operating nuclear plants in the country has consistently run at 80% capacity factor or better. Were the capacity factors of newer nuclear plants steadily improving over their elders, it might be fair to assume a gradual (not drastic) improvement in future operation, as did the AEC. But nuclear capacity factors have held steady at 52-58% since the 1960's. Utility industry trade magazine Power, in a special report by the editors, reviews the "relatively poor track record" of successive nuclear plant designs:

> The [third] generation--consisting essentially of the first plants over about 800-MW--has shown little improvement over the second in many instances; in some cases it has even done worse. A few of the still-more-advanced units have not fared any better.[31]

Louis Roddis declared, in a speech to the Atomic Industrial Forum, that nuclear plants would never fulfill their "expectation of deliverability." A Wall Street Journal survey of operating (and non-operating) nuclear plants reported, "their unreliability is becoming one of their most dependable features," citing typical examples of reactor shutdown:

> The incredibly complex facilities are plagued by breakdowns that experts blame on faulty engineering, defective equipment, and operating errors. Failures range from hours-long annoyances to months-long closedowns. Repair costs often run into millions of dollars, and some utilities stoically shell out up to $200,000 a day for replacement electricity to distribute to their customers in the meantime.
>
> For example, within the past year, in addition to the Millstone fiasco [involving costly replacement of defective reactor parts], a routine 10-week refueling at a Wisconsin Electric Power Co. plant grew into a five-month closedown for turbine and steam generator repairs the company says were to correct design mistakes. A Yankee Atomic Electric Co. plant in Rowe, Mass., needed a six-month $6 million repair job when some bolts failed in the reactor core. And a steam valve blew at a Virginia Electric Power Co. plant killing two workers. Another steam line ruptured at a Florida Power & Light Co. plant, apparently as a result of an engineering fault, and two other plants had to have defective fuel replaced. Operating licenses of six reactors were restricted because of fuel problems. . .
>
> Such breakdowns have caused no blackouts yet. But in the future, more and more power will be coming from nuclear stations--as much as 50% by the year 2000--and then failures could be traumatic not only for utilities but for consumers as well.[32]

Since then numerous boiling-water reactors have been shut down for inspection and repair, the disastrous Brown's Ferry fire closed two 1065-MW reactors, and the Humboldt

Bay nuclear plant has been recommended for shutdown because of a recently discovered earthquake fault, among countless reactor outages. In an average six-month period one-fifth of the nation's nuclear plants will be forced out of service for safety or performance problems (in addition to routine re-fueling shutdown), and many plants are restricted by the NRC to operation at low power levels.

The Wall Street Journal survey unkindly but accurately termed them "atomic lemons." Dr. Norman Rasmussen of Massachusetts Institute of Technology, whose $3 million study judged nuclear plant safety systems nearly 100% reliable, addressed the performance question with puzzlement:

> Probably one of the most serious issues that the intervenors can raise today, with good statistics to back their case, is that the nuclear power plants have not performed with the degree of reliability we would expect from machines built with the care and attention to safety and reliability that we have so often claimed.[33]

It is generally agreed that the capacity factor of a nuclear plant improves gradually for the first four to twelve years of service, followed by a steady decline for the remainder of the plant's life. Peter Margen and Soren Lindhe, Swedish engineers who are vigorous champions of atomic power, estimate nuclear reactors (all sizes) would average only 42.7% capacity over their 30-year lifetimes. Comey explains why:

> Corrosion problems set in, leaking fuel becomes a problem, and system components break down due to fatigue and other wear-related problems. An additional hazard is the accumulation of highly radioactive crud in the primary system, which means that any repair work on this system will consume enormous amounts of time and personnel in order to avoid excessive radiation exposure. In some instances, thousands of workers have had to participate in the repair of a single plant, and a worker can receive his maximum permissible exposure after working on the primary system for less than sixty seconds, thus "burning him out" for the next three months.[34]

An engineer for Consolidated Edison agrees:

> Radiation build-up of this nature creates severe manpower availability problems due to the exposures encountered and greatly increases the cost of any work to be done. . .[35]

Although data from nuclear plants over seven years old is limited because there are few plants in that category, it is not encouraging. Older plants operate at less than 40% of capacity.

Operating and maintenance costs for nuclear plants rise quickly as capacity factors drop. Repair expense is obviously one reason, but there is another: the cost of replacement electricity, which is usually omitted from utility nuclear cost estimates. However, it is real to utility customers. Con Edison, cited above, paid $200,000 per day for replacement electricity when its Indian Point reactor broke down, while Consumers Power of Michigan spent $7 million per month to make up for power lost when its Palisades nuclear plant was undergoing repairs. If a reactor produces only 20% less electricity than expected (operates at 55% of capacity rather than 75%, for example), the costs of



replacement electricity can exceed the total annual reactor fuel costs, adding 10 mills per kWhe or more to total plant costs, according to Dr. Charles Komanoff, engineer and utility analyst for the Council on Economic Priorities.[36]

For this report estimates, we have taken the cumulative operating experience of all 1000-MWe-plus reactors through 1 April 1976, and calculated the overall capacity factor at 44.3%. We then excluded the still-smoldering Brown's Ferry reactors from the calculations (assuming that Black Fox 1 and 2 won't repeat their fate) as well as the newer Trojan plant in Oregon, and re-calculated the average capacity factor for remaining large plants at 52%. While this average should decline in the long run as these plants age, we assume some improvements in reactor efficiency may raise capacity factors as high as 55%. Business Week warns:

> Utilities started planning 1100 megawatt nuclear plants before even seeing how plants half that size worked out.[37]

and experience will have to tell. For now, any projected capacity factor higher than 55% would be contrary to generally accepted experience and estimates and will have to await improvements in reactor technology sufficient to justify it.

We accept PSO's judgment that Black Fox 1 and 2 will operate for 30 years although no operationally-proven data underlie this estimate. No nuclear station in the country has operated longer than 18 years, and no large unit (500-MWe-plus) has operated longer than 8 years. Surprises are possible in either direction, but optimism must be tempered by the fact that current nuclear plants are not wearing as well as expected.

We also accept PSO's estimate of 2.65 mills/kWhe (1.2 mills/kWhe fixed, 1.44 mills/kWhe varying with plant output) operation and maintenance costs, although excessive shutdown time will inflate these costs considerably. We feel that PSO should include the costs of replacement electricity both in fuel and in operation and maintenance costs because PSO contends the Black Fox plants are needed to meet system power demand. We do not include replacement power costs, either as fuel or as operation and maintenance, because we don't feel all of the Black Fox power will be needed for system demand anyway, even if replacement power were available from other sources. If PSO and its partners in the Black Fox project will really need a reliable supply of electricity at the levels they project, they will have to begin planning a Black Fox 3 station equal in size to the first two.

(6) Fuel Costs

> The problems of nuclear power go far beyond simple dollars-and-cents calculations. They thread through practically every segment of the nuclear fuel cycle.
>
> - Business Week, "Why Atomic Power Dims Today," 17 November 1975

Unraveling PSO's nuclear fuel cycle costs from information presented in the Environmental Report is impossible. Details are haphazardly presented, and only the overall totals are firm: PSO projects an average 30-year levelized fuel cost of 5.13 mills/kWhe for Black



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Fox 1 and 2 and anticipates using 4,500 tons of natural uranium ($U_3O_8$, or "yellowcake") processed into 1,230 tons of enriched uranium fuel.*

Suffice it to say that the usual cost projection order is re-established:

(a) PSO makes one estimate,

(b) the Atomic Energy Commission offers a higher estimate,

(c) other utilities planning nuclear units estimate still higher, and

(d) operating experience of current nuclear plants indicates much higher future costs than any of the above. For (b), (c), and (d) above, the cost indicators are as follows:

(b) Atomic Energy Commission, 5.6 mills/kWhe nuclear fuel costs in 1982 with 8% annual escalation, or 7.0 mills/kWhe in 1985, while the Nuclear Regulatory Commission estimates 8.1 mills/kWhe for 1985.

(c) other utilities, including New York Power Pool and Seattle City Light, 8-11 mills/kWhe in 1985.

(d) estimates based on current fuel costs, current reactor operating efficiency, and prevailing escalation rates, 12-23.2 mills/kWhe, according to studies by Komanoff, California Energy Commission, Rand Corporation, et al.[38]

Some of PSO's assumptions which led to its extraordinarily low fuel cost estimates can be isolated. PSO, for example, expects an astounding 107 million kilowatt-hours of electricity to be generated by the Black Fox stations for each ton of natural uranium mined (480 billion kWhe generated by two 1150-MWe stations over 30 years at 80% capacity factor divided by 4,500 tons of natural uranium mined) and 30,350 thermal megawatt-days per ton of enriched uranium fuel (see fuel cost derivations). PSO assumes that 1,230 tons of enriched uranium fuel can be obtained from 4,500 tons of mined uranium. Not even the most enthusiastic advocate of nuclear power is on record with assumptions such as these.

The AEC, with usual early-1970's optimism, predicted that a 1000-MWe nuclear station would consume roughly 6,350 tons of natural uranium "yellowcake" in its 40-year lifetime, generating roughly 44 million kWhe for each ton mined. Yields as high as 60-70 million kWhe/ton of natural uranium were hopefully forecast, assuming breakneck speed in improving reactor efficiency.

As with all such previous hopes, experience has dimmed them to a considerable degree. The published estimate is now 209 tons of "yellowcake" per 1000-MWe reactor per year, or 14,395 tons of "yellowcake" over the 30-year lifetime of Black Fox 1 and 2. Even that seems optimistic alongside the operating experience of today's reactors.[39]

According to ERDA figures, average reactor yield to date, excluding such low-mileage plants as Dresden 2 and Indian Point, has been only 19.8 million kWhe/ton of natural uranium, or 16,700 thermal megawatt-days/ton of enriched fuel. ERDA's figures may well be

* "Ton," unless otherwise stated, means metric ton," equal to 2,205 pounds or 1000 kg.



on the generous side. U.S. Mining Enforcement and Safety engineer Morgan G. Huntington, after extensive study, calculated that current gross electricity production from all U.S. reactors to date has averaged only around 14 million kWhe/ton of natural uranium (11,800 thermal megawatt-days/ton of enriched uranium) and that 22 million kWhe per ton of natural uranium (18,600 thermal megawatt-days/ton of enriched uranium) is the most that can be expected.[40] Data from California utilities indicate that Huntington's figures are closer to actual reactor experience.*

Industry and advisory sources are not much more enthusiastic. Nuclear proponent Dr. Hans Bethe, writing in April's <u>Scientific American</u>, cites the ERDA-33 report which states that reactor "manufacturers now maintain they are confident their fuel will meet the guarantees of about 25,000 MW(t)d/ton for Boiling Water Reactor fuel." While reactor manufacturers have been guaranteeing this for years without delivering, this last-stated figure sets a good upper bound for what Black Fox 1 and 2 may accomplish under optimum improvements in reactor efficiency by 1985.

Since it is impossible to derive PSO's projected fuel costs in detail from the Environmental Report, we have re-figured Black Fox fuel costs on an annual basis, summarized in Table 2. The assumptions and formulas involved in calculating nuclear fuel cycle costs are generally accepted and may be used by anyone familiar with elementary algebra (the calculations of the quantity of fuel needed by the Black Fox plants are detailed in Appendix 1). Estimates of future reactor efficiency require judgments on how much performance will improve or regress. Our cost estimates are based on the following data which is the most recent obtainable from industry sources:

(a) We assume the Black Fox plants will average 55% of capacity over their 30-year lifetimes, which means they will generate around 11.1 billion kWhe per year.

(b) We accept the industry estimate that, in the future, boiling-water reactors will extract 25,000 thermal megawatt-days/ton of enriched uranium, or 29.7 million kilowatt-hours of electricity for each ton of natural uranium mined--a 50% improvement over the most generous estimates of present reactor performance. This improvement will be difficult to achieve if capacity factors are not significantly raised.

(c) Calculating fuel needs is tricky, because it depends upon the ability of the utility to predict in advance the capacity factor and burnup rate. Unlike fossil-fuel plants, nuclear plants cannot be stoked with a little extra uranium if needed; the whole nuclear plant must be shut down and re-fueled, a costly and time-consuming process utilities prefer to do only once a year. Too much fuel loaded will mean too much

* The Atlantic Council, hardly an anti-nuclear group, gave their best estimate of reactor efficiency as 200,000 kWhe/kilogram of enriched uranium, or 25,600 MW(t)d/ton of enriched uranium for all reactors. Boiling-water reactors derive only about 75% as much energy from their fuel as do pressurized-water reactors but can operate with less-enriched fuel.[41]



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unburned uranium left at the end of the year; too little will mean early re-fueling or operation at lowered capacity--all of which entail higher fuel costs. We assume PSO will predict and achieve 55% capacity factor even though this is extremely difficult. Vogt and Carlson, of Nuclear Assurance Corporation and Georgia Tech, stated:

> To date, mainly due to poor fuel performance, over half of the operating nuclear power plants have been forced to replace fuel prematurely.[41]

(d) Natural uranium ($U_3O_8$) prices are estimated at $58/lb. in 1985. In 1975 uranium prices were at $25/lb., three to four times higher than in 1973, and Business Week reported utilities paying $38/lb. for 1980 delivery.[42] By February 1976 utilities were buying uranium at $40/lb. on the spot market, $50/lb. for 1980 delivery on contracts which specified payment of market price at time of delivery if higher than $50/lb. Ebasco Services recommends an escalation rate of 7%/year, the AEC 8%/year, both of which assume drastic reduction in current 100%/year escalation. The key to stabilization in uranium prices lies in whether new high-grade resources are discovered (see uranium assessment in this report), but this is by no means assured. A comprehensive uranium study by Mitchell Hutchins of New York, the nation's second largest investment consulting firm, expressed alarm:

> Uranium will remain in short supply--ie., available only at a rising price--both short and long term. . . as is the case of "cheap" oil, the days of "cheap" under $100/pound uranium may be gone for good.[43]

The Mitchell Hutchins report noted that prices up to $300/lb. by 1985 were conceivable. We assume, with reservations, that uranium supplies will expand and that uranium prices will stabilize in the 1980's for purposes of cost estimates used in this report; if neither happens, no nuclear cost estimates of any kind will be needed.

(e) Enrichment costs, measured in SWU (Separative Work Units, or the work needed to enrich 1 kilogram of 0.711% $U_{235}$ uranium to 3.0% $U_{235}$ uranium fuel), have risen sharply since ERDA's proposal that government enrichment prices be raised to a "commercial" level of $76/SWU in 1976. An ERDA official and several utilities have estimated 1980 SWU costs at $100, and modest 7%/year escalation would yield charges of $140/SWU by 1985. If enrichment is turned over largely to private enterprise, as is now intended, costs will probably be much higher since private operators would have to profit, pay taxes, and buy commercial electric power to run enrichment facilities (currently uranium enrichment consumes 2-3% of the electricity produced in the United States).[44] PSO has an ERDA contract, but ERDA will have to match private charges. SWU charges of $140 are assumed.

(f) Prices for conversion to uranium hexaflouride ($UF_6$) are based on estimates by Edison Electric Institute of $6/kilogram of uranium.[45]

(g) Fuel reprocessing (recovery of unburned fissionable $U_{235}$ and plutonium from used reactor fuel) is a shaky prospect at present but may become feasible if uranium prices continue to spiral upward. Comprehensive reprocessing should not be automatically assumed. Edison Electric Institute, a national investor-owned utility trade association,



TABLE 2

NUCLEAR FUEL CYCLE COSTS, 1985

| FUEL CYCLE STEP | COST/UNIT | QUANTITY/YEAR | ENRICHMENT | COST/YEAR |
|---|---|---|---|---|
| Mining and Milling | $58/lb $U_3O_8$ | 649,595 lbs | 0.711% | $ 37,677,000. |
| Conversion to $UF_6$ | $6/kgU | | | |
| IN | | 249,874 kg* | 0.711 | |
| less 0.5% process loss | | 1,250 kg | 0.711 | |
| OUT | | 248,624 kg | 0.711 | 1,499,000 |
| Enrichment | $140/SWU | | | |
| raw IN | | 248,624 kg | 0.711 | |
| raw OUT (153,769 SWU) | | 44,429 kg | 2.6 | 21,528,000 |
| recycle IN | | 54,408 kg | 0.85 | |
| recycle OUT (43,695 SWU) | | 13,016 kg | 2.6 | 6,117,000 |
| total OUT (0.3% tails assay) | | 57,445 kg | 2.6 | |
| Process Recycle** | | 4,323 kg | 2.6 | |
| Fuel Preparation and Fabrication | $105/kgU | | | |
| IN | | 61,768 kg | 2.6 | |
| less process recycle** | | 4,323 kg | 2.6 | |
| less 1% process loss*** | | 618 kg | 2.6 | |
| OUT | | 56,827 kg | 2.6 | 6,486,000 |
| Reactor | | | | |
| IN | | 56,827 kg | 2.6 | |
| less 3% burnup | | 1,704 kg | 2.6 | |
| OUT | | 55,123 kg | 0.85 | |
| Reprocessing and Storage | $235/kgU | | | |
| IN | | 55,123 kg | 0.85 | |
| less 1% process loss | | 551 kg | 0.85 | |
| OUT | | 54,572 kg | 0.85 | 12,954,000 |
| Reconversion to $UF_6$ | | | | |
| IN | | 54,572 kg | 0.85 | |
| less 0.3% process loss | | 164 kg | 0.85 | |
| OUT (recycled in enrichment step) | | 54,408 kg | 0.85 | |
| | | SUBTOTAL | | $ 86,261,000 |
| | | 16% FUEL CARRYING CHARGE | | 37,092,000 |
| | | NET FUEL CYCLE COSTS**** | | $123,353,000 |

* 1.179 lb $U_3O_8$ equals 1 lb U, and 1 kg equals 2.205 lbs.

** Sum of 2% process recycle in preparation and 5% in fabrication steps.

*** Sum of 0.5% loss in preparation and 0.5% loss in fabrication steps.

**** True believers in plutonium recycle can subtract a plutonium credit of $14 million, or 1.3 mills/kWhe, from these figures.

offered a caveat in a 10 July 1975 report:

> Reprocessing and recycle of uranium and plutonium should be included in utility industry planning when and if there is a clear and compelling economic advantage associated therewith and as government regulation allows. Based on today's cost estimate, the beneficial economic impact of reprocessing and recycling is expected to be small, if indeed, positive.
>
> A combination of (a) escalating cost; (b) unresolved health and safety, environmental and safeguards regulations; and (c) lack of resolution of the closely related high-level radioactive waste treatment and long-term storage problem all together make reprocessing and recycle poor candidates for acceptance today as firm factors in utility industry planning.
>
> At best, reprocessing and recycle may come to represent a modest contribution to the solution of very large uranium oxide and enrichment supply problems.

Komanoff agrees, for virtually the same reasons:

> Reprocessing and recycle are unlikely because of (i) radiological and safety issues, (ii) possible reduced value of recycled uranium due to impurities, and (iii) the high cost and technical uncertainties of reprocessing itself.[46]

Nuclear reprocessing industries would agree with these assessments. At present there are no commercial scale reprocessing facilities operating anywhere in the world. Nuclear Fuel Services' reprocessing plant in West Valley, New York, is closed for extensive expansion and overhaul to reduce radiation exposure and effluent problems, and NFS is looking to unload the whole operation. General Electric completely abandoned its $64 million Morris, Illinois, plant as a technical failure. Allied-General's new reprocessing facility in Barnwell, South Carolina, is in similar straits: components necessary for plant operation are estimated to cost twice as much as the original plant, and plutonium handling facilities are questionable additions. Everyone is poking around for federal help.[47]

The "marginal economic value" of reprocessing alluded to by EEI may be further eroded by the presence of un-fissionable $U_{236}$ contamination in spent fuel. Bertram Wolfe, General Electric Company's General Manager of Fuel Recovery and Irradiation Products, estimated fuel reprocessing would cost $250/kilogram in 1985, five times original projections. Utility executives responding to an EEI survey cited figures in the $220-250/kg. range. Dr. Marvin Resnikoff, physicist at the State University of New York at Buffalo, predicted reprocessing would cost 40% more than the value of recovered uranium and plutonium in 1980, or $148/kg., with costs escalating at perhaps 9%/year.[48] We use a median estimate of $235/kg. for $U_{235}$ recovery, but we feel it is premature to claim credit for plutonium recycle before NRC approval and demonstration of appropriate technologies.

(h) ERDA now sets the allowable $U_{235}$ content of the "tails" discarded from uranium enrichment plants at 0.29%, soon to be raised to 0.3%. This will significantly increase feed requirements and costs to utilities. We assume a "tails assay" of 0.30%.[49]

(i) Fuel is financed in much the same manner as capital items. The fuel inventory is carried before and after use in the reactor. Thus a normal 16% fuel carrying rate equals carrying charges of about 43% of the total fuel costs per year.



C. URANIUM AVAILABILITY

> Given. . . the uncertain supply of uranium we cannot look on this [nuclear energy] as any savior. And I think it's important to realize that no significant uranium supply has been found in this country in the last two years, despite an intensive search.
>
> \- Dr. Charles Mankin, Director, Oklahoma Geological Survey, 18 July 1976[50]

> This supply uncertainty is compounded by the restrictive export policies of of foreign uranium producers, particurly Canada and South Africa. If and when the US finds itself (marginally) dependent upon foreign sources for uranium, there is no guarantee of continued US access to that supply in competition with other (e.g., Japanese, Western European) buyers.
>
> \- the Atlantic Council Nuclear Fuels Policy Working Group[51]

> Demand. . .is projected to be far greater than any resource estimates that can be made on the basis of present factual information.
>
> \- Hans Adler, ERDA Nuclear Fuel Cycle and Production Division[52]

While nuclear energy has been promoted as an electricity source which would supply as much as 50% or 60% of our power needs and reduce the need for dependence on foreign fuel supplies, serious questions have been raised regarding the adequacy of domestic uranium reserves to fuel such an ambitious nuclear program. A recent comparative report by the Nuclear Regulatory Commission indicated that nuclear power plants--per 1000-MWe per year--used up a larger percentage of their known fuel reserves than did oil-fired or coal-fired power plants and nearly as much as natural gas-fired plants.[53] Extrapolating from the NRC's figures, only 167 1000-MWe nuclear plants could be fueled using domestic reserves for 30 years, while 333 oil-fired, 83 natural gas-fired, and 5,550 coal-fired plants of 1000-MWe each could be fueled from their domestic fuel reserves.

Westinghouse, the nation's leading uranium supplier, found itself unable to provide 50 million pounds of natural uranium to utilities at the contracted prices and defaulted, prompting law-suits. General Electric, the second largest supplier, announced a 20 million pound deficit but is apparently awaiting resolution of the Westinghouse case before deciding on a course of action. And Homestake Mining Company has taken legal action to absolve itself of a contract to provide 150,000 pounds of uranium to Washington Public Power System.[54]

The message has not been lost on utilities. Florida Power Corporation announced in January 1976, that it would build no more nuclear plants until uranium fuel was assured. South Carolina Gas & Electric followed suit.[55] Virginia Electric Power Company reported to its stockholders that "the extent to which the company can obtain uranium for its requirements" after mid-1977 "is not known." And Commonwealth Edison of Chicago, the nation's largest nuclear utility, admitted it had no idea where its uranium would come from after 1980; its fuel manager could only say, "We must believe the resources will be there to keep those monsters running."[56]

Overall, ERDA's figures showed 40% of the nation's committed nuclear generating capacity has "no uranium supply arrangements" for even the first fuel core; 90% had no contractual arrangement beyond the seventh annual fuel reload. Only eight of the nation's fifty-six operating nuclear plants had any kind of agreement for uranium fuel after the seventh annual re-load (1982). Uranium suppliers, in fact, are currently offering firm contracts on a two-year basis only; 1980's supply contracts offer an indefinite escalation clause or often only "market price at time of delivery," whichever is higher. Suffice it to say that such uncertainty is not present in the coal industry, where firm 25-year contracts may be obtained at specified escalation rates.[57]

PSO has no contract for uranium supply and offers no opinion as to where its fuel for the Black Fox stations will come from.[58]

The questions are: will the uranium supply deficiencies straighten themselves out as the price of uranium goes higher and higher? How much higher? Or do they reflect a real shortage of uranium resources which no reasonable expenditure will relieve?

Opinions are widespread. There is general agreement that the stated official goal of 1,000 large nuclear plants operating by the end of the century will not come to pass. Even the more recently stated goal of 700 large reactors is very doubtful. PSO's Black Fox units will be approximately the 200th and 210th nuclear plants to come on line, if the nuclear program advances more or less as docketed. Whether or not uranium supplies will be adequate depends on what set of assumptions are adopted.

The most authoritative study of domestic uranium reserves is being done by ERDA and the U.S. Geological Survey. Called National Uranium Resource Evaluation (NURE),* the study seeks to determine the extent of uranium reserves which may ultimately exist in the United States. The emphasis is not only upon estimation of proven reserves, but also estimation of total potential reserves, a very inexact proposition. The necessary uncertainty is apparent from ERDA's description of resource evaluation methodology:

> The basic assumption is that the potential resources of an area being appraised may be approximately equal to those of a thoroughly explored area, provided that both are similar with respect to size and certain key physical and geologic characteristics. . . From knowledge of these characteristics, criteria of favorability for types of deposits can be developed, thus providing a basis for quantifying estimates of potential resources in inadequately explored areas. The recognition and assessment of these favorability criteria in known areas, and their extrapolation to areas under appraisal, is the basis for ERDA estimates of potential resources.[59]

The pitfall in this type of analysis is pointed out by Professors Raphael Kazmann and Joel Selbin, of Louisiana State University's Departments of Civil Engineering and of

* To which critics add the prefix, "Mathematically Arbitrary."



Chemistry, respectively:

> The record shows that it is easy to total up postulated resources based on geologic analogies but that it is difficult to convert these undiscovered resources to fuel you can count on.[60]

Consequently, ERDA's uranium reserve estimates are optimistic compared with other estimates of potential supplies. The preliminary NURE estimates, along with explanations of the particular resource category appraised, are as follows.*

| CATEGORY | DESCRIPTION OF CATEGORY | METRIC TONS ULTIMATELY RECOVERABLE |
|---|---|---|
| Proven Reserves | Includes proven reserves and by-products from other mining operations. | 710,000 |
| Probable Potential Resources | Those estimated to occur in known productive uranium districts: (1) in extensions of known deposits, or (2) in undiscovered deposits within known geologic trends or areas of mineralization. | 980,000 |
| Possible Potential Resources | Those estimated to occur in undiscovered or partly defined deposits in formations or geologic settings productive elsewhere within the same geologic province. | 1,150,000 |
| Speculative Potential Resources | Those estimated to occur in undiscovered or partly defined deposits: (1) in formations or geologic settings not previously productive within a productive geologic province, or (2) within a geologic province not previously productive. | 540,000 |
| TOTAL RECOVERABLE URANIUM RESOURCES | | 3,380,000 |

TABLE

ERDA'S PRELIMINARY ESTIMATE OF TOTAL URANIUM RESERVES[61]

ERDA, officially at least, is inclined to be optimistic:

> Guarded optimism is warranted that significant increases in the present resource estimates will result from current and future investigations.[62]

But few other analysts, including geologists who compiled the ERDA survey, are so optimistic. For reasons apparent from the descriptions of resource categories given above, the lower categories are considered of doubtful value.

Assuming that all the proven and probable uranium resources are successfully utilized, less than 300 large nuclear plants could be fueled for their 30-year lifetimes, using assumptions outlined in Table 2. Using current reactor performance data, only 130 nuclear plants could be fueled. Thus the Black Fox plants would be assured of uranium fuel

* The thoroughness of ERDA's survey in covering "a wide variety of geologic environments" is evidenced by ERDA's definition of "productive": "past production plus known reserves exceeds 10 tons $U_3O_8$." Included are all reserves which can be recovered at a "forward" cost of $30/lb or less, which is expressed in 1975 dollars and excludes "past expenditures for property acquisition, exploration, and mine development" and "are independent of the market price at which the estimated resources would be sold."[63] When ERDA and other sources express estimates in short tons, we have converted them to metric tons for the sake of uniformity.

supplies for operation at full capacity only if the nuclear reactor program tapered off quickly after they were built. In this latter case, the nuclear program will have siphoned off large amounts of capital without providing a large share of electricity in return, compared (as always) to alternative energy sources.

Thus the factors which may work to improve uranium fuel availability are vital to projecting the viability of the Black Fox stations, and include:

(a) discovery of new fuel reserves and technology to exploit them,

(b) importing uranium,

(c) development of the breeder reactor at an early date,

(d) a labyrinth of governmental actions, including arbitrary uranium price ceilings, stockpiling and sale of fuel to utilities at a large discount, and/or development of low-grade uranium reserves at public expense. These possibilities are taken one by one:

(a) Discovery of new reserves. ERDA's optimism in this regard has been noted. Also expressing optimism (using ERDA figures as a data base) are a conglomerate of government agencies under the title of Federal Energy Resources Council, which concluded:

> The adequacy of uranium to provide fuel (over their 30-year lifetime) for all existing plants and additional reactors which may be placed into service by 1990 is a reasonable planning assumption.[64]

The adequacy assumed is in the neighborhood of 2 million tons of $U_3O_8$, three times presently known reserves.

Several independent geological analyses cast doubt on the ERDA figures, and several of the geologists who worked on ERDA's preliminary survey are in disagreement with official estimates and interpretations. Geologist Hans Adler, with ERDA's Nuclear Fuel Cycle and Production Division, stated:

> Demand. . . is projected to be far greater than any resource estimates that can be made on the basis of present factual information. . . a number of predictions, based on largely statistical treatment, have accorded the eastern half of the U.S. the same degree of favorability for uranium discovery as the western half. Such treatment. . .appears to be contrary to available geological evidence.[65]

Over 90% of proven U.S. uranium reserves are in the West. Dr. M.A. Lieberman, electrical engineer with the Energy and Resources Group at the University of California at Berkeley, agreed with Adler's conclusion:

> As far as is now known, the western sandstone deposits are a unique geological occurrence in terms of their extent and magnitude.[66]

And Robert D. Nininger, ERDA nuclear fuel specialist, notes the uncertainty of postulated resources:

> Some portion of it may not exist and some may not be found in time.[67]

The summaries of resource evaluations given in ERDA's survey indicate the previously-cited uncertainty is quite large. While ERDA includes about 130,000 tons of uranium available from mining other products in the "proven resources" category, it subsequently



concedes that "the future quantity of by-product uranium output will be dependent on the demand for phosphoric acid." Much of the postulated resources are couched in terms such as, "postulated to occur," "discovery possibilities exist," and "deposits may occur." In one example, ERDA projects 71,000 tons of uranium oxide for the Central Lowlands region of the U.S. althouth it "contains no important uranium-mining areas." Seventy-seven thousand tons are estimated for the Appalachian Highlands although only "small deposits are known." The Columbia Plateau is assigned 18,000 tons although thick lava flows "probably will deter exploration" in much of the area. "Possible" and "speculative" resource projections mean just what they say.[68]

Warren I. Finch, chief of the U.S. Geological Survey's Uranium Resources Branch, noted that uranium discoveries needed amount to <u>five times</u> that found so far "if the nuclear power industry is to survive on domestic fuel." But what would that require? Discovery of nine uranium-bearing regions equivalent to the giant four-state area known as the Colorado Plateau, or of two hundred new areas equal in mineralization to the Wyoming Basins region. "The major question confronting exploration geologists," says Adler, "is where in the U.S. will facsimiles of these two regions be found even once, much less 9 or 20 times."[69]

In these terms, outside the pencil-and-paper speculations which have understandably had to substitute for working knowledge, the uranium supply problem seems formidable indeed. "No major uranium deposits have been identified in this country in the last seventeen years," Frank Armstrong, also of the U.S.G.S. Uranium Branch, stated, despite intensive exploration efforts by both public and private interests.[70] Ray Dickeman, president of Exxon Nuclear Corporation, calls current uranium finds "disappointing."

The generally-accepted reason is that high-grade ore (having a uranium content of 500 parts per million or more)--which is currently the source of nuclear fuel--is rapidly dwindling, and intermediate ores (100-500 ppm) are curiously lacking. A <u>Wall Street Journal</u> assessment concluded:

> Geologists are especially concerned because they think most of the easy-to-find uranium deposits near the surface have already been discovered.

The remaining ore is "very expensive to mine;" obtaining the 100,000 tons of ore needed annually by the year 2000 would require mining low-grade shales covering 100 square miles of land per year at costs of \$100 to \$200 per pound "with devastating environmental effects." Despite official hopes that the low-grade (60-80 ppm) shales can be used as a fall-back when richer deposits are gone, "most government and mining-industry officials figure the shale will never be mined."[71] The net energy obtained in any case would be low, requiring several times the energy and cost of mining equivalent coal.

Siegfried Muessing, uranium expert for Getty Oil, agrees:

> In spite of increased knowledge of the way uranium occurs, the ore bodies

> are getting harder and more expensive to find. . . This results not only from the increased depth at which (ore) targets must be sought, but perhaps also from an increasing scarcity of these targets.[71]

ERDA's survey notes further that the quality and grade of ore is dropping, from an average of 0.24% uranium oxide in 1965 to 0.16% today, and the recovery of potential $U_3O_8$ is also lower--93% compared to 95% ten years ago. Low-grade ores have $U_3O_8$ concentrations of 0.01% or less, and $U_3O_8$ losses will be even higher. Factors such as these make extrapolation of the usefulness of lower-grade reserves difficult.[72]

Many experts in the field of resource projections--including Dr. M.C. Day of Louisiana State University; Dr. M. King Hubbert, former explorations director for Shell Oil and now geophysicist with the U.S.G.S., perhaps the foremost energy resource expert in the country; Morgan Huntington of the U.S. Bureau of Mines; and Lieberman--are critical of ERDA's "geological analogy" methods. Lieberman in particular states that ERDA's "estimates of undiscovered resources. . .are not based on any objective procedures that I can discern," and notes that "the way this [geological analogy] procedure may tend to produce large overestimates is described extensively" in a report to the Senate Committee on Interior and Insular Affairs by Hubbert. The ERDA total, concluded Lieberman, required "16 separate estimates" of which "many are based on considerable speculation."[73]

Lieberman, Hubbert, Huntington, and others substitute two resource projection methods widely used in industry: (i) projection based on amount of resource discovered per foot drilled on a continuing basis, and (ii) a "logistic growth curve" of yearly data on production and reserves. Hubbert, using these methods, accurately predicted U.S. oil reserves as long ago as 1956. Lieberman explains why these techniques have a reputation for accuracy:

> Economic and political conditions act to determine the exploratory footage drilled in a given year, but have little influence on the discoveries found per foot drilled. As Hubbert has stated in connection with petroleum exploration: ". . .the officials of a large oil company may authorize its staff to double the amount of exploration drilling in any given year and consequently increase discoveries per year; no oil company management, however, can successfully order its staff to double the quantity of oil to be found per foot of exploratory drilling."

ERDA data show that the ratio of pounds of $U_3O_8$ discovered per foot drilled decreased from a high of 18.6 in 1956 to 2.4 in 1974. Independent estimates of the ultimate quantity of $U_3O_8$ which may be found in concentrations greater than 200 ppm show remarkable consistency: Hubbert predicts only 675,000 tons will be recovered, with 590,000 already discovered; Lieberman calculates that only 80,000 tons remain to be discovered and that total production will not exceed 570,000 tons; Huntington's figures parallel those of Hubbert. All agree with Day and Lieberman:

> Based on the optimism expressed in AEC documents, one may feel that the solution to the uranium shortage is simply that of more exploration, and perhaps it is. In terms of the record to date, however, it would seem there is little basis for such optimism. . . the pounds of uranium oxide per foot drilled has decreased significantly. . .[74]



> The success of discovery indicates that little high-grade uranium ore remains to be discovered. . . a serious shortfall in uranium supply will develop during the late 1980's.[75]

At 200 ppm or less, uranium deposits will yield less energy per ton of ore mined than will coal. Recovery of these low-grade resources will be physically and technically possible, but monetary and environmental costs will be so great that many utilities may find it cheaper to abandon their nuclear plants altogether. Day, in fact, calculates that each ton of 70 ppm uranium shale mined would yield only 980 kWhe, compared with 2,250 kWhe per ton of bitumin us coal mined.[76] Nuclear power would then lose its only economic advantage--the promise of lower fuel costs.

The General Accounting Office, in a preliminary report to Congress in February, 1976, forecast a severe uranium shortage within the next ten years.[77] Even Oak Ridge National Laboratory, the government's giant nuclear engineering installation in Tennessee, predicted through its information office,

> There will be a shortage of uranium. . . [between 1980 and 1982] all known reserves of uranium will be commited for reactors that will operate 30 to 40 years after that.[78]

And ERDA, acknowledging that a "statistical basis for establishing confidence limits" in its survey figures "has not yet been developed," stated that "uranium supply arrangements for planned U.S. nuclear fuel capacity do not provide extensive coverage of future needs." In recognition of the supply problems, ERDA is prepared to allow utilities to import 10% of their uranium in 1977, with allowable imports rising to 100% by 1983.[79]

For most of the nuclear and utility industries, a coming domestic uranium shortage seems to be a foregone conclusion. "It is probably too late to avoid an important uranium import program," says Exxon's Dickeman.[80] If Lieberman, Huntington, Day, Hubbert, et al. are correct, we will reach the maximum number of nuclear plants which can be maintained on domestic resources within two years, if we have not already.

(b) Uranium Imports. Dependence on foreign uranium and the potential of cartel-controlled prices is not an appealing prospect. Even so, many observers are not optimistic that large increments of foreign uranium will be available if needed to offset domestic shortfall. The Atlantic Council writes:

> The world uranium market consists of a limited number of producing and exporting countries, whose resource allocation and trade policies today tend to discourage the export of natural uranium. . . The limited number of national sources of uranium, and of sources of enrichment services, may be contrasted with the many nations. . .having nuclear power plants in operation, under construction or planned.[81]

And Sir John Hill, chairman of the United Kingdom Atomic Energy Authority, states:

> The world's proved resources of uranium in the grades presently exploited are not large, and all these will be committed to conventional reactors ordered up to the end of this year [1975].[82]

By 1985 the U.S. is estimated, if the nuclear program advances, to have around 30% of the world's installed nuclear generating capacity, but only 29% of the world's uranium reserves. Nations with no large domestic oil, gas, or coal resources--such as Western Europe and Japan--will compete fiercely for uranium imports. Mitchell Hutchins concludes:

> Foreign nuclear programs will absorb the bulk of these foreign supplies. The remainder of these foreign reserves are only likely to be made available to domestic utilities at prices geared to the domestic industry's rapidly rising supply/demand-determined price level.[83]

That is, cartel-controlled prices which, says Forbes magazine, "the users, with tens of billions tied up in capital-intensive plant, would have no choice but to pay."[84] The Atlantic Council, again, observes:

> Formation of a formal (OPEC-like) uranium cartel could occur. Reserves are, so far at least, concentrated in only a few countries. However, the market perception may well be that informal action by each exporter will amount to the same thing as formal cartelization. Where numbers of sellers are few, the possibility for tacit cooperation is always great. If these few countries or companies which possess a significant portion of the non-Communist world's economically marketable uranium also control nationally, or as the principal participant in a multinational arrangement, a significant portion of the non-Communist countries' enrichment capacity, then by choosing different tails options (more uranium and less enrichment, or vice versa), these few countries or companies potentially can control the non-Communist world price of uranium and enrichment. This potential development could be effectively acted upon by the US only by the rapid expansion of domestic uranium reserves and production capacity, and enrichment capacity.[85]

Of the eight potential uranium-exporting countries surveyed by the Atlantic Council, only one, Australia, was seen as a possible major source of supply. Australia is currently experiencing a vigorous debate concerning the safety of uranium mining and the wisdom of exporting nuclear materials, and what its export policies will be remains a mystery. At best, capacity will be no more than 2,600 tons/year by 1979. Canada, another country with uranium reserves, is expected between now and 1985 to offer "firm export commitments, between 1985 and 1990 conditional export commitments, and after 1990 no exports because of domestic requirements," according to the Atlantic Council. None of the remaining countries known to have major uranium deposits--France, Niger, South Africa, Gabon, Sweden, and the Soviet Union--is seen as a major exporter.[86]

Even ERDA expresses little confidence in the reliability of foreign supply.[87] At best imports may serve a temporarily significant buffer against domestic resource drain--if they are not counterbalanced by U.S. uranium exports. Through 1980 the United States has committed 10,600 tons of $U_3O_8$ to foreign markets and contracted for 13,700 tons in imports.

(c) Development of the breeder reactor. The liquid-metal fast breeder reactor (LMFBR), whose fission process creates more fissionable fuel from low-grade uranium resources than the reactor itself consumes, promises to extend the supply of uranium available for conventional reactors as well as generating electricity at the same time.

PSO is not ordering a breeder. Nor is the breeder expected to have any significant impact on either the price or the availability of fuel for conventional reactors of the proposed Black Fox type. LMFBR advocate Dr. Ralph Lapp writes that even early development of a commercial breeder "would have no significant effect on uranium requirements in the year 2000," although it would possibly depress uranium prices later on.[88] And Lieberman concurs:

> It is clear that on the time scale discussed, the planned introduction of the breeder reactor can play no role. . . Even a "crash program" to develop the breeder will be unable to forestall the coming supply and demand uranium squeeze; it is far too late. (Whether the breeder will ever compete economically with light water reactors is another question which is not addressed here and is still unresolved).[89]

Speedup in breeder deployment is not expected by any responsible authority; delay is far more likely. Federal breeder development program costs have soared from $2 billion to $10-12 billion. ERDA believes the potential economic benefits will be great. The Joint Economic Committee of Congress and the conservative American Enterprise Institute disagree, concluding that the breeder will be so costly to develop that "none of the [hypothesized] cases will show a net discounted benefit from the LMFBR."[90] The National Resources Defense Council, with support from the General Accounting Office estimates that for every dollar in energy benefits from the breeder, the government must spend ten dollars in development subsidies.[91]

The root of the problem is technical. The high neutron flux in current breeder designs causes metal cladding on fuel assemblies to swell, reducing coolant flow and threatening a major accident. Leaving more space between fuel assemblies slows down the "breeding rate" considerably. Estimates from the U.S. demonstration breeder indicate that it will require 20-60 years to double its original quantity of fissionable fuel. The French Phenix, the only breeder in the world to operate even reasonably well, has a doubling time of 60 years. Utilities, with bitter memories of the serious accident which completely scrapped Detroit Edison's Enrico Fermi breeder in 1966 during its first power ascension, will not rush to invest in the new breeder even if technically available. The LMFBR's technical, safety, and economic problems are such that its effects on the fuel supplies of the Black Fox plants is likely to be negligible.

(d) Government intervention. There is no way to predict accurately what the federal (or state) government will do as the economic problems of the nuclear industry multiply. Currently ERDA is practicing a schizophrenic policy with regard to nuclear fuel supply. On the one hand ERDA is providing uranium enrichment services at low cost and promising the availability of its approximately 45,000 metric tons of $U_3O_8$ at bargain rates of $11/pound (even though it cost ERDA $14/pound) to utilities unable to contract for uranium supply through the private market. The cost to taxpayers of this arrangement could run into the billions of dollars. On the other hand ERDA is, in an effort to cut enrichment costs in its budget, steadily increasing the "tails assay" of uranium wastes so that utilities must provide ever growing quantities of raw uranium to receive the same enriched fuel product. Science magazine's Allen L. Hammond questioned this arrangement:

> Uranium will without question eventually be in short supply, and the nuclear power industry is already experiencing financial trouble. It would seem difficult, then, to defend [ERDA] enrichment policies that exacerbate both problems.[92]

However, the nuclear industry has little grounds for complaint because ERDA still enriches uranium at far less cost than would private industry.

The moral of the enrichment tale is that the government giveth and taketh away. Whatever federal help PSO and the nuclear industry receive will be born in equivalent amounts by taxpayers and thus may be of little comfort to electricity consumers.

The larger problem involved in federal (or state) intervention is that the market price of nuclear-generated electricity becomes even more hopelessly distorted, utilities (in the words of American Electric Power's Donald Cook) are led even further "down the wrong road," and the consumer is unable to make intelligent choices because the true price isn't there to serve as a gauge. Yet federal action to save the $80 billion nuclear industry remains a possible development.

In sum, then, large uncertainties exist with regard to uranium supply which neither foreign imports nor development of the breeder reactor can be expected to alleviate. Something in the neighborhood of at least 1.5 to 2 million tons of $U_3O_8$ must be domestically produced if the Black Fox plants are to have sufficient fuel to operate to the year 2015. If tentative and admittedly sketchy NURE estimates are accurate, such uranium resources exist in reasonable quantity. If, however, such experts as Dr. M. King Hubbert and others, using industrially-proven projection techniques, are correct, more than two-thirds of the needed uranium will have to come from ill-defined, low-grade, enormously expensive uranium deposits which will in all probability destroy the economic viability of the nuclear fuel cycle. Uranium price estimates by Mitchell Hutchins of $200-300/pound as early as 1985 and the warnings of the Atlantic Council will take on a new meaning:

> Specific uncertainties concerning the capital requirements for expanding the (private) uranium mining and milling industry derive from the difficulty in extrapolating cost experience to the grades of ore which will have to be mined in the future. Also, the capital requirement for spent fuel storage and waste disposal is in part contingent upon the unresolved issues of reprocessing and recycling. . . At the level of risk involved, current interest rates are not good indicators of the discounting required to consider the relative profitability of investments five or ten years hence.[93]

The final results of the NURE program won't be available until 1981 and probably won't be evaluated for several years after that. In the meantime uncertainty persists. Is the risk worth taking? Examination of alternatives to the Black Fox nuclear stations may help answer that question.



## D. ALTERNATIVES TO BLACK FOX

> We note a distinct tendency in the nuclear energy literature to underestimate nuclear power costs, more often than not by simply omitting some costs, or neglecting the potential effects on costs of practical or operational experience such as significantly lower capacity factors than theoretical projections would suggest.
> - Richard J. Barber Associates, Washington consulting firm[94]

> All things considered, it appears that purely on economic grounds and ignoring shortage problems resulting from state regulation of electricity rates, the future of the United States nuclear reactor industry is less bright than most recent Government forecasts indicate.
> - Paul L. Jaskow, M.I.T. Economics Department, and Martin L. Baughman, Associate Director of Energy Modeling, University of Texas, in the Bell Journal of Economics and Management Science[94]

> Publicly available information on the costs of nuclear power versus other alternatives tends to strongly overstate the case for nuclear power and understate the case for the alternatives.[94]
> - report to ERDA

> I agree there was a dream, and five years ago, when we were generating power at $100 a kilowatt, the dream seemed justified. Right now, it looks like the dream has ended, but I caution you all the returns aren't in. At this moment, though, it is probable that nuclear energy is going to be a great deal more expensive than enthusiasts such as myself first thought.
> - Dr. Ivan M. Weinberg, nuclear scientist and consultant[94]

> Utilities have been led down the garden path by the reactor people. . . The only place on the planet where you can make a case for nuclear power 8 or 10 years out is New England.
> - Prof. Irvin C. Bupp, Harvard Graduate School of Business Administration/Center for Policy Alternatives, M.I.T.[95]

> An erroneous conception of the economics of nuclear power. . .was largely responsible for sending the electric utility industry down the wrong road. The economics that were projected, but never materialized--and never will materialize--looked so good that the companies couldn't resist it.
> - Donald C. Cook, Chairman, American Electric Power Company, the nation's largest utility system[96]

As noted earlier, PSO's figures indicate its customers will spend around $7.8 billion over 30 years to build and operate the Black Fox plants. Current cost estimates outlined in this report indicate the total costs will exceed $11.5 billion. In return, the Black Fox plants are expected by PSO to produce over 260 billion kWhe within the PSO service area (less if current capacity factors prevail). This total, again assuming PSO projections are accurate, would mean the Black Fox plants will generate 25% of PSO's peak power demand in 1985 and 8% of the total power demand between 1985 and 2015.[97]

The question of alternatives, then, is simple to offer and difficult to answer: in what other way can PSO's service area be supplied with the equivalent of 25% of its electricity and peak power requirements by 1985 for an equivalent cost?

POOR ORIGINAL



719 284

719 126

It is very unsettling to rea[illegible] that it will cost us $8 billion to supply 8% of our energy needs between 1985 and 2015. One wonders what the other 92% will cost. And where a small-to-medium-sized service area like PSO's is going to raise the astronomical sums necessary to finance such an energy appetite.

Fortunately there are good alternatives. Most of them depend more on what PSO's customers do than what PSO does. There is every reason to believe electricity demand is slowing down its rate of growth considerably, removing the need for vast new additions to generating capacity. Systematic conservation programs may accelerate this decline even further. Use of alternative solar energy sources, primarily for heating and cooling, can sharply reduce demand if applied on a commercial scale.

As may be apparent from this introduction, the best solutions do not depend on one approach, but combine approaches in a flexible manner. If nuclear plants generated electricity at 25 mills/kWhe, their inflexibility and temperamental natures could be overlooked--there would be no good alternatives from an economic standpoint. Conversely, at generating costs of 50-70 mills/kWhe, nuclear energy has so many good alternatives and competitors that it may well disappear altogether.

For short-range planning, and assuming that growth in electricity consumption continues, we will analyze the economics of the following alternative:

. Planning and construction of three 650- or 675-MW coal-fired plants in place of the nuclear stations, scheduled to come on line in 1985, 1986, and 1987. The problems of coal generation are large, but not so large as nuclear. Such medium-sized coal-fired plants promise to generate electricity at least 18-33% cheaper than the large Black Fox nuclear stations even using pessimistic assumptions. Employment benefits would be 40% greater than nuclear investment.

The potential of the following alternatives to reduce long-range utili[illegible] demand in an economical way will be briefly assessed, with detailed applications to the PSO service area offered in a later report:

. Comprehensive energy conservation measures designed to reduce peak load and overall electricity demand, based on successful applications elsewhere in the country and projected benefits. Such measures can be implemented with little or no reduction in "standard of living" and a net increase in employment.

. Installation of solar radiation and wind energy equipment which could greatly reduce utility demand for heating, cooling, and hot-water supply, both in the 1976-85 period and beyond. Electricity systems may even become competitive. Employment benefits would be two to four times greater than nuclear investment would yield.

The following factors will a[illegible]d in the reduction in ne[illegible] generating capacity:

. Electricity conser[illegible]ation prompted by rising prices of energy, which PSO future demand project[illegible]s do not take into account. Additionally, the PSO service area has become saturated with electricity-consuming air conditioners and home appliances, a[illegible]d further increases from this sector will not be large.

. Industrial and governmental electricity consumers in the PSO service area have already undertaken programs to reduce their energy consumption, with benefits already becoming apparent. Large consumers are exploring ways to generate their own power.

. A slowdown in the construction of new electricity generating plants, which consume startling quantities of electricity. The Black Fox plants alone, exclusive of transmission facilities, will consume an amount of electricity equal to 24% of the total projected increase in demand during their construction.

. A gradual reduction in PSO's electricity sales to outside utilities and steady improvement of the capacity factor of PSO's generating plants (which is feasible because many of PSO's plants are not base-loaded), which could virtually remove the need for new construction before the year 2000 to meet a relatively modest increase in electricity demand (but not a large increase in peak demand).

The difficulty lies in formulating an effective public energy use policy which will overcome the current state of inertia.



(1) Coal

The principal problems involved in using coal as a power plant fuel do not concern fuel supply, nor technical problems, nor private/public industrial shortfalls, nor the host of unsolved riddles which plague the nuclear industry from one end to the other. The coal industry is troubled instead by the prospects of too much success--how to quickly develop coal mines and rail transportation systems to supply growing demand, how to solve labor and management problems that periodically threaten--and attendant environmental attrition--the effects of strip mining, Western water supply for coal processing, particulate and sulphur oxide pollutants from burning high-sulphur coal. The Atlantic Council listed seven "potential constraints" on the expansion of the coal industry:

(a) Required Capital--expansion to target levels will probably require an additional 25-30 billion dollars of investments in an industry which is currently capitalized at 5 billion dollars.

(b) Required Manpower--an additional 125,000 miners and 10,000 mining engineers are required for an industry which is having trouble meeting current demands.

(c) Impact of Health and Safety Regulations--decreased productivity due to more rigorous application of mine health and safety legisl[illegible]tion is expected to continue.*

(d) Impact of Unions--the impact of an increasingly powerful coal miners' union may affect productivity as the industry expands.

(e) Impact of Strip Mining Legislation--delays in the expansion of the industry due to uncertainties surrounding proposed strip mining legislation are likely to affect the industry's ability to expand.

(f) Transportation Requirements--expansion to target levels will require the substantial upgrading of railroads, particularly th[illegible]se i[illegible] the Northeastern US, and maximum utilization of alternative coal slurry pipelines.

(g) Impact of Air Pollution Regulations--there are major unresolved issues as to the allowable discharges from coal burning electric generating stations and the facilities (scrubbers) to be used in controlling discharges.[98]

Several of the above "constraints"--such as Required Capital, Required Manpower, Impact of Health and Safety Regulations, Impact of Unions--apply equally to the future of the

* The alternative appears to be perpetuation of the extreme hazards of coal mining, restitution of which currently costs the federal government nearly $1 billion per year in aid to disabled miners and families. Enforcement of mining safety and health regulations appears to cut fatalaties and injuries by a factor of ten or more.

nuclear industry. But transportation, strip mining, and air pollution problems are real. In the late 1960's and early 1970's these disadvantages, and the rampant optimism of nuclear sales departments, tipped the economic balance briefly in favor of nuclear stations. That balance, outside the Northeast where coal transportation problems are most acute, is now shifting rapidly back to coal.

Resolution of air pollution and strip mining problems presents few technical difficulties--West Germany, for example, reclaims strip-mined land with virtual 100% success, and de-sulphurization equipment already installed on coal plants promises to reduce sulphur emissions to negligible levels. Yet these solutions are expensive and troublesome.

The assured supply and technical familiarity of coal and coal systems make it an economically stable fuel, relatively speaking. Major coal suppliers offer contracts on a 25-year basis at predictable escalation rates, contrasting with the maximum two-year uranium supply contracts and radical escalation demands which have characterized the nuclear fuel industry. Prolonged coal plant outages are rare. Few government or industry observers expect coal prices to escalate uncontrollably as the coal industry expands:

> The costs of producing coal do not increase rapidly as coal production is expanded.
> - Federal Energy Administration[99]
>
> The long-term equilibrium price of coal in most locations west of the Appalachians will be relatively independent of the long-term rate of growth and demand.
> - Pr. ident s Council on Wage and Price Stability[100]
>
> The outlook for coal prices in the next decade is favorable. . .with good prospects for stable prices (in 1975 dollars) and in some parts of the country declining prices. . . the development of western coal reserves will place substantial downward pressure upon coal prices.
> - Ibid
>
> Over a period of several years, supplies of coal will increase greatly, and increases in the cost of producing coal will result--to a considerable degree, at least--in reduction of profit margins, rather than an increase in coal prices.
> - Investor Responsibility Research Center[101]
>
> In sharp contrast to other fuels in the United States energy mix, coal's contribution to meeting our energy requirements is demand constrained.
> - Mitre Corporation[102]

A brief "environmental impact" comparison between coal and nuclear stations is offered in Appendix 2. We see no reason to believe that either the environmental effects or the fuel supply difficulties will be greater for a well-maintained coal-fired plant than for a well-maintained nuclear plant, and technical certainties are on the side of coal.

The best coal alternative to two 1150-MW nuclear plants is not two 1150-MW coal plants. Fuel costs are higher for coal plants, and fuel efficiency gained by building medium-



sized coal stations more than offsets their slightly higher capital costs. A base-loaded 600-MW or 650-MW coal plant will run at a consistent capacity factor of 70-75%, which means that only three such stations would have to be built to supply the equivalent of two 1150-MW nuclear plants. If medium-sized units are built, later units may be cancelled or deferred if expected demand doesn't materialize, and coal's lower fixed costs means that plants may be shut down and fuel conserved if demand drops after the plants are built. The lead time needed to built coal plants is much less than for nuclear plants--only 6-7 years are required, so that 1978 would be a reasonable starting date for planning coal units scheduled to come on line in 1984-86.

On the surface, the current industry debate over whether coal- or nuclear-generated electricity is cheaper appears as an ambiguous squabble between two competing special interest groups seeking to present their own fuel in the best light. One utility executive argues for nuclear, another for coal, while the National Coal Association and the Atomic Industrial Forum fight it out on a national basis. Yet there are significant patterns in the debate, even given the large uncertainty about future costs of energy.

According to Professor Irvin C. Bupp, whose Harvard Business School department and colleagues at Massachusetts Institute of Technology have been studying nuclear economics for the past three years,

> The only way you can conclude that nuclear power will be cheaper eight to ten years from now is to make systematically optimistic assumptions about nuclear costs and be systematically pessimistic about coal.[103]

The one exception cited by Bupp and others is the Northeastern United States (another possible exception is California, but this is less certain). There air pollution regulations, high rail transportation distances and costs, and the high sulphur content of eastern coal make coal-generated electricity more expensive than anywhere else in the world. Utility executives in the Northeast--including those of Consolidated Edison of New York, Boston Edison, Jersey Utility Corporation--insist that nuclear power is the best choice for their generating units. Bernard Schwartz of Consolidated Edison declares that "there's no contest in our state."[104]

The other general group insisting nuclear energy is cheaper than its alternatives is (predictably) the nuclear industry itself. Ebasco Services, a major reactor consulting firm, released a well-reasoned report report last August estimating that nuclear plants should generate electricity for 2 mills/kWhe cheaper than coal plants--assuming both units operated at a 75% capacity factor. Business Week examined Ebasco's report and asked, "But will the (nuclear) plants perform that well? In the past they have not."[105] Substituting actual operating capacity factors for coal and nuclear plants makes coal by far the cheaper choice.

Another survey, this time by the Atomic Industrial Forum (AIF), concluded "that the total cost of a kilowatt hour (kwh) produced by nuclear power. . .was 12.50 mills. This



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is 63 percent less than oil (33.38 mills) and 27 percent less than coal (17.14 mills)." There were several major flaws in the AIF survey, however:

(a) Only 18 utilities reported both coal and nuclear costs to the AIF survey, and 12 of these were located in the far East and Northeast. Conspicuously omitted were such poorly-operating nuclear plants as the Brown's Ferry reactors and Commonwealth Edison of Illinois' malfunctioning nuclear units.

(b) The cost of nuclear electricity is still artificially low because of the impact of "loss leader" reactors sold at below commercial prices by reactor manufacturers during the 1960's, and of below-market-value fuel contracts now facing default.

(c) The cost of replacement power due to power plant outage or low capacity factors was apparently not included. In fact, as Business Week and others noted, there is a good deal of evidence that utilities are ignoring some costs and underestimating others associated with nuclear units.*[106]

The AIF's own figures, broken down by region, yield some interesting results:

| | Far East and Northeast | Midwest |
|---|---|---|
| Average nuclear cost/kWhe | 12.67 mills | 14.96 mills |
| Average coal cost/kWhe | 19.10 mills | 14.75 mills |

Now that it is generally conceded that nuclear fuel and capital costs are rapidly outrunning coal costs, by a margin of 5%/year (according to utility analyst Lewis Perl) or $18/kw/year (in 1973 dollars, according to Bupp et al), coal seems by far the best economic choice for utilities outside the Northeast. Oklahoma Gas & Electric Company's president, James Harlow, reported the results of his utility's examination of coal and nuclear costs in the April 1976 OG&E Meter bulletin:

> The results of the study indicated low-sulfur Wyoming coal was far and away the best solution. . . We did, at the time the decision was made, seriously consider construction of nuclear plants. However, the long lead time and high capital costs discouraged us, and we still have not committed for any nuclear capacity.[107]

Other midwestern and southwestern utility analysts seem in general agreement with this

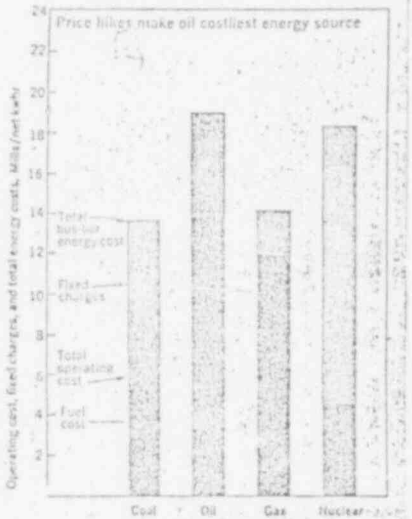
* Commonwealth Edison is a good example. Com Ed's president, Thomas Ayers, estimated nuclear savings to his customers of $100 million in 1974. Later examination of Com Ed's records by David Comey showed that Ayers had incorrectly calculated capacity factors, omitted plant capital and operating costs, and left out altogether two of Com Ed's nuclear units which raised overall nuclear costs. A later letter from Com Ed to Comey revealed that the utility's five best nuclear units actually generated electricity at 7% higher cost than its five best coal units in 1974, while Comey pointed out that use of operating capacity factors for 1974 (33.0% for nuclear units and 52.8% for coal) meant that nuclear-generated electricity cost 16.4 mills/kWhe, coal 10.8 mills/kWhe. Consolidated Edison of New York similarly claimed a $95 million cost advantage due to operation of its Indian Point nuclear units, but analysis by Komanoff and others showed that Con Ed had compared only the costs of nuclear fuel to oil fuel. A total cost comparison, including capital amortization, fuel, and operation and maintenance, concluded that the Indian Point nuclear units actually cost $18 million more to own and operate than comparable coal units. It may be that assessment of full costs in this manner will show that nuclear power is not economically viable even in the Northeast.[108]



assessment. They are supported in their judgment by an impressive array of independent studies such as the one by Harvard Business School and M.I.T., already cited.* Another study by the Energy Task Force at Washington University in St. Louis concluded:

> Under a series of different assumptions about the price of fuel, the addition of pollution controls to coal-fired plants, and the improvement in nuclear plant capacity factor. . . by 1985 nuclear power will probably become more expensive than electricity produced by coal-fired plants.[109]

Another survey, this time by the reputable utility industry trade magazine Electrical World, of 30 generating plants outside New England found nuclear electricity costs nearly as expensive as oil, and 30% higher than coal. All plants surveyed were of modern design and reflected sharp increases in electricity costs. Since the price of nuclear units now planned is three to five times higher than those which now comprise the majority of operating reactors, the fact that nuclear plants have already lost their economic advantage is a bad omen for the future.




ELECTRICAL WORLD'S NINETEENTH BI-ANNUAL POWER PLANT COST SURVEY, 15 NOVEMBER 1975.

There is, in short, not so much ambiguity in conflicting claims regarding nuclear power economics if (a) the region of the country, (b) total generating costs, and (c) actual operating experience of nuclear plants are accounted for. Nuclear plants are currently competitive in the East and far West but are overtaking coal costs even in these areas. "Systematically optimistic" or "systematically pessimistic" assumptions can distort future projections to a large degree, but the basic pattern of nuclear economic deficiency using any reasonable set of assumptions remains. If the federal government shifts its research funding preoccupation away from nuclear (which currently generates 8.5% of the nation's electricity) toward coal (which now generates 44.6% of our electricity), renewable energy sources, and conservation, nuclear economics will suffer even more.

We have projected the costs for three medium-sized coal plants scheduled for operation

* Other studies citing coal's advantage over nuclear, cost-wise, include those by Bank of America in California, the Investor Responsibility Research Center in Washington, D.C., the Rand Corporation, and the California Energy Council, among others. The National Coal Association obviously agrees.[110]

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in 1984, 1985, and 1986, with results summarized in Table 4. Cost assumptions are:

(a) Capital costs are assumed to be $760/kWe for three 600-MWe coal stations which burn low-sulphur coal, and $920/kWe for three 650-MWe stations burning high-sulphur coal. These costs are considerably higher than those forecast by either PSO or Oklahoma Gas & Electric Company and are intended to be very conservative. OG&E has estimated costs for a completed low-sulphur coal station at $240/kWe in 1977-78, while PSO is planning two 450-MW coal plants with "advanced design precipitators" to control emissions for $375 million ($420/kWe) for 1979-80. At high (10%/year) escalation, PSO's estimate would add up to costs of $720/kW by 1985; $600/kWe at 8%/year escalation. Estimates from twelve utility, industrial, and government sources show average 1985 coal plant costs at around $700 for low-sulphur stations and $850 for high-sulphur stations.[111] Another set of estimates, this time from three nuclear industry sources, indicate low-sulphur coal plant costs averaging 70% of nuclear plant costs; high-sulphur coal plant costs around 85% of nuclear costs ($714/kWe and $867/kWe respectively, using our nuclear cost estimate of $1,020/kWe).[112] Our estimate is intended to be pessimistic and reflect some of the costs of developing controls to meet stringent emission standards we hope will be imposed on any new coal plants (the Interior Department now estimates that half the coal burned in power plants does not meet clean air standards), even though all above cost projections include advanced pollution control equipment. No credit is assumed in our estimate for simultaneous on-site construction.

(b) "Scrubbers" for high-sulphur coal burning plants are variously estimated to add $75-175/kWe to the cost of a coal plant. We have chosen an estimate at the high end of this range because de-sulphurization is the most experimental technology in coal generation.[113]

(c) We assume operation and maintenance costs for low-sulphur stations 10% higher than those for nuclear plants, 80% higher for high-sulphur plants. (Northeast Utilities estimated high-sulphur coal plants would have operation and maintenance costs 40% higher than nuclear plants; Georgia Power predicted coal costs only 13% higher.)[114]

(d) Fixed charges of 20%/year for 30 years are assumed.

(e) The average life of a coal-fired plant is 40-50 years. To fairly compare coal and nuclear costs, one would have to either (i) estimate the costs of ten years of new generating capacity to replaced the de-commissioned Black Fox nuclear plant in 2015, or (ii) levelized fixed coal plant costs over 40 years and represent total costs in straight-forward mills/kWhe terms.* We have chosen the latter.

(f) Capacity factors of 72% for base-loaded low-sulphur coal stations and 65% for high-sulphur coal stations are assumed, based on historical data. Data from Edison Electric Institute and the Council on Economic Priorities show average capacity factors for all fossil units larger than 390-MWe was 64%, but only 90% of the units were base-loaded. Thus the real capacity factors were calculated at 64% divided by 90%, or 71%, with coal units showing generally higher capacity factors than oil or gas units.[114] We

*OG&E, for example, amortizes coal units over 40 years.



assume only marginal improvements in these capacity factors and a 7% capacity factor penalty for use of de-sulphurization equipment.

(g) OG&E estimates, on a 1977 contract, that the price of delivered coal will be $15/ton from Wyoming ($5 fuel, $9 transportation, $1 carrying charge). Escalating coal costs at the same 8%/year rate afforded uranium prices (although uranium is currently far outpacing coal in cost escalation), transportation costs at 10%/year, and adding a fixed charge of 16% yields 1985 low-sulphur coal costs of:

| | |
|---|---|
| Coal (at mine) | $ 9.25/ton |
| Transportation | 19.30/ton |
| 16% FCR | 4.57/ton |
| TOTAL | $33.12/ton |

We estimate, to allow for maximum strip-mining and union wage cost increases, a price of $40/ton for low-sulphur Western coal, $50/ton for high-sulphur Eastern coal. Oklahoma is relatively favorably situated for Western coal and even has considerable deposits of high-sulphur coal within PSO's service area. A 1985 coal cost of $30/ton delivered or less could easily be defended on the basis of current trends.[115]

TABLE 4

1985 COAL PLANT COSTS

| COST ITEM (1985 DOLLARS) | LOW-SULPHUR STATION 3 600-MWe PLANTS | | HIGH-SULPHUR STATION 3 650-MWe PLANTS | |
|---|---|---|---|---|
| Capital costs* | $1.368 billion | | $1.794 billion** | |
| - per kilowatt of capacity | $760 | | $920 | |
| - fixed charges on debt, 30 years | 20% | | 20% | |
| - in mills/kWhe, levelized over 40 years | | 18.1 | | 24.2 |
| Operation and Maintenance charges, in mills/kWhe, levelized over 40 years | | 3.0 | | 5.1 |
| Coal fuel costs, in mills/kWhe, levelized over 40 years*** | | 18.2 | | 18.0 |
| Other costs | | 3.1 | | 3.1 |
| TOTAL COSTS, IN MILLS/kWhe, LEVELIZED OVER 40 YEARS | | 42.4 | | 50.4 |
| COAL PLANT PERFORMANCE ASSUMPTIONS | | | | |
| Expected operating life | 40 years | | 40 years | |
| Capacity factor, 40-year average | 72% | | 65% | |
| Total kWhe generated/year, 40-year average | 11.353 billion | | 11.103 billion | |
| Power yield, BTU/lb. coal | 9,500 | | 13,000 | |

* About 6% of the power is used on-site. These plants are actually 635-MWe low-sulphur, 690 high-sulphur in size. Cost estimates use only salable capacity.
** Includes de-sulphurization equipment to meet stringent air quality standards.
*** Calculated by the following formula: $\frac{\text{Heat rate} \times \text{Price/lb.}}{\text{Heat content}}$, where heat rate equals 9,500 BTU/kWhe low-sulphur, 10,000 BTU/kWhe high-sulphur; price/lb. is expressed in mills; and heat content equals 9,500 BTU/lb low-, 13,000 BTU/lb high-sulphur.

(2) How Accurate are Demand Projections?

The feasibility of substituting energy conservation and renewable power programs in place of the Black Fox stations depends on the economics involved and on the pattern of electricity usage within the PSO service area in coming years. These concepts are closely related.

Currently PSO's generating plants, all natural gas-fired, have an average capital cost of $1(?)/kWe and generate electricity at less than 10 mills/kWhe.[116] At these costs energy conservation is not an economic necessity, taking a short-range point of view, and most alternative energy systems are priced out of the market. Thus energy conservation and use of renewable power sources have been promoted in the past on moral, patriotic, and environmental grounds, not immediate economics.

It has not been this way in many areas of the United States, however, and Oklahoma's era of cheap energy seems destined to come to an end soon. Nuclear plants generating electricity at 60 mills/kWhe and coal-fired plants at 40-50 mills/kWhe indicate future electricity isn't going to be a commodity which can be carelessly wasted. The advice of FEA Administrator Frank Zarb will seem only realistic:

> Contrary to myth, conservation is vital to our efforts to sustain our high standard of living and rekindle economic growth. Moreover, several recent analyses have shown that reducing the inefficient use of energy would not result in an employment penalty and may, in fact, create more jobs.
>
> Saving energy is synonymous with saving dollars and can, in fact, be considered as one of the least expensive energy supplies this Nation has.[117]

The first consideration involves what pattern of energy usage is likely to prevail in the Tulsa area and how the increasing price of electricity will affect this pattern. In order to justify the proposed addition of 2500-MWe of generating capacity to its system by 1985 (1,400-MWe of the Black Fox stations plus 1,140-MWe in coal units planned between 1978 and 1985), PSO projects peak load demand--the maximum electrical demand made on the generating system and the demand used to determine needed generating capacity--will grow at an annual mean rate of 7.4%. Also, PSO assumes that total electricity usage will grow at an annual average of 6.2%.*[118] And, PSO recently announced in an article in the Tulsa World that electricity rates would increase 39% in five years and 75% in ten years, mainly as a result of cost entailed in building the Black Fox stations.

The purpose of this section is to explore the following questions: (a) Do historical electricity consumption trends support PSO's projected growth trends? (b) What is the relationship between increasing electricity costs and demand? and (c) Are there alternatives to PSO's proposed nuclear plants which would be better for our economy?

* The figures "7.4%" and "6.2%" are the means of annual percentage changes in peak load and total electricity demand, respectively, from 1976 to 1986, found in PSO's Environmental Report on the Black Fox Stations.



(a) Historical electricity consumption trends. Utility companies have tended to base their projections of future demand on historical growth patterns which took place in a period of rapid population growth, rapid increases in per-capita consumption, and declining electricity prices. These assumptions are apparently becoming increasingly invalid.

The annual growth rate in electricity consumption predicted by PSO for the next ten years--averaging 7.4%/year in peak demand growth and 6.2%/year in overall demand growth--is not derived in the Environmental Report on the Black Fox stations. It is therefore difficult to tell what assumptions about the market are made. However, examination of PSO's most recent Annual Report and other economic indices for the Tulsa region shows several major factors which are working against a high rate of growth in electricity consumption:

(i) The average annual growth rate has dropped off sharply since 1970, both for peak demand and overall per-capita demand:

| Electricity Sales, PSO | 1966-70 period | 1971-75 period |
|---|---|---|
| Average annual growth rate, peak demand | 12.6% | 5.7% |
| Average annual growth rate, per capita | | |
| - Residential customers | 10.0% | 5.3% |
| - Commercial customers | 8.4% | 5.4% |
| - Industrial customers | 11.0% | 7.0% |

Consumption per capita and peak demand are now increasing at much slower rates than PSO has projected. If PSO builds for a peak load projection increasing at 7.4%/year, and the actual increase is only 5.7%/year, they will be overbuilding by 30% in ten years.[119] The difference represents tens of millions of dollars in 1985 bills to PSO's customers.

(ii) Population growth in the Tulsa area is slowing down. Figures from INCOG show the average annual population growth in the Tulsa region from 1910 to 1970 was 3%. Population growth forecasts to the year 2000, however, indicate a average of 1.4% to 1.9%/year. These predictions are reflected in national trends which show a continually decreasing birth rate and reduced migration to the cities. The growth in the number of customers in PSO's system, measured in five-year periods, was 10% lower in the 1971-75 period as in the 1966-70 period. This slowdown is expected to continue.

(iii) If the Tulsa area follows national trends, the percentage of senior citizens living within the INCOG area should increase from its current level of 14%. For reasons not completely understood, older citizens use much less electricity than younger residential customers. Data from studies done by Dr. Shirley J. Smith for the Oklahoma Coalition for Older People indicates the elderly on moderate income use only 74% as much electricity as the average residential customer, elderly low-income customers use only 56% of the average, and poverty-level older citizens use only 40% of the average.[120]



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(iv) Construction activity within the Tulsa region is decreasing. The annual total dollar value of residential construction contracts has been decreasing since 1973; non-residential construction has been decreasing since 1974. Both residential and non-residential new building permits have been dropping since 1972. Multi-family dwelling permits have decreased since 1973.[121]

(v) The PSO service area has already become saturated with energy-consuming household appliances. One of the largest contributors to peak load, and peak load growth, is the residential air conditioner, and 75% of the homes within PSO's service area already have this appliance. Over half have electric ranges. Thus there is not likely to be much future growth resulting from this sector.[122]

(vi) Many of the major industries and state institutions in the PSO service area are already implementing conservation programs aimed at significantly cutting electricity consumption. Cities Service, for example, has an announced goal of 20% less electricity consumption by 1985, and other industries have similar programs. Oil and gas extraction and refining, which currently consume about 20% of PSO's industrial power sales, may operate at lowered capacity due to declining production from the state's oil and gas fields.[123] Oklahoma state agencies have already decreased their electricity consumption 12% since 1973, and larger cuts are planned in the future. The increasing cost of utility-generated electricity will encourage both electricity conservation programs and the use of on-site generating units by very large industrial and governmental consumers, as will be discussed later. The potential for such conservation is enormous; beginning conservation programs in several large California industries have shown cuts in electricity usage from 23% to 31% in one year, while Los Angeles' commercial sector has sustained a 30% reduction in electricity consumption for the past two years in response to an energy conservation program implemented by Los Angeles County.[124]

(b) The relationship between increasing electricity costs and demand. PSO's projections of rapid growth in demand indicate they don't believe the rising cost of electricity will appreciably affect demand. This assumption is contrary to a massive volume of data which has accumulated since the general rise in the cost of electricity began in 1967, after a 2-year national decline in price which had characterized the 1950's and early 1960's.

A recent Federal Power Commission study judged that utilities which make demand projections based on simple extrapolation of past growth are overestimating 1980 demand by about 30%. The FPC explained the reasons for its conclusions:

> The past growth of electricity consumption can be attributed to three factors: an increase in population, an increase in real income per capita, and a decrease in the price of electricity relative to other commodities. It is the implications of this latter relationship that are generally ignored by industry personnel. Since price is found to be an important determinant of demand, recent rates of growth of electricity consumption will be maintained only if there are substantial price decreases in the future. . . Current projections of future demand which omit price effects may seriously exaggerate the need for generating capacity.[125]



The FPC found the growth in electricity demand slowing in all nine geographical regions surveyed.

The measure of the relationship between price and demand is "price elasticity,"* a basic index in the market system. Current price elasticity data is not theoretical. It is based on experienced reduction in demand in response to rising electricity bills elsewhere in the country and is categorized by short-run (less than 1 year) response and long-run response (5-7 years). Representative price elasticity studies are summarized below from electrical industry data:

| Study[126] | Response | Price Elasticity, Electricity Demand Residential | Commercial | Industrial |
|---|---|---|---|---|
| Dr. Lester D. Taylor | long-run | -1.0 | -1.0 | -1.2 to -1.9 |
| Dr. Duane Chapman, Cornell Univ. | long-run | -1.17 | | |
| Data Resources, Inc. | long-run | -1.0 | -1.5 | -1.5 |
| Oak Ridge National Laboratory | long-run | -1.0 | -1.4 | -2.5 to -3.5 |
| - second study of 14 most energy-intensive industries (56% of industrial demand) | short-run<br>long-run | | | -.29 to -1.66<br>-1.6 to -2.0 |
| FPC Task Force | short-run<br>long-run | -.31<br>-1.17 | -.54<br>-1.22 | -.27<br>-1.00 |
| National Economic Research Assoc. | long-run | -.5 | -.5 | -.5 |

Short-run response to rising electricity price is considerably more limited than long-run and consists largely of such measures as turning down thermostats, turning off lights, etc. Long-run response can include more productive measures such as better design of new buildings, retrofitting old buildings, changes in working arrangements to reduce electricity usage, and so on. These measures are described in the next section.

The studies are in unanimous agreement that demand falls in response to real price increase. Although the general rise in the cost of producing electricity in Oklahoma began in 1972, the effects have not really been passed on to the consumer until the past ten months or so--such is the time lag in base rate adjustments. Short-run reductions in electricity consumption should just now be apparent in the PSO service area, adjusted for weather anomalies. If all of the above studies are correct, PSO's constant rate of high growth demand projections against rising electricity costs are unrealistic.

The average percentage of income spent by the residential customer on electricity bills in the Tulsa area between 1966 and 1975 was 1.6%. PSO projects a rise in the real cost

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* "Price elasticity" is calculated by dividing the change in demand for a commodity by the change in its price. If a rise in price of 2% causes a drop in demand of 1% (that is, a change in demand of -1%), then the price elasticity is -1%/2%, or -.5. The real price elasticity formula is logarithmic, but the values are similar and the relationship is the same. The "price" means the real price, adjusted for inflation.



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of electricity over the next ten years of 75%, which will be much higher if PSO's underestimation of the Black Fox costs is considered). Using three assumptions--a growth in family income of 5.6%/year, a rate of residential population growth of 2.3%/year, and a total residential sector consumption of 23% of PSO's electricity--then PSO will have to charge residential customers an average of 2.2% of their income to balance revenues. This would be a real increase of more than 35% in the cost of electricity to consumers.

If the summarized price elasticity studies are valid, residential electricity consumption should fall by about that same amount, per household, with commercial and industrial reductions as great or greater. Nationally this seems to be the trend; since 1973 reductions in per-capita consumption have balanced population growth so that electricity demand has remained virtually constant. And studies by the Oklahoma Coalition for Older People has shown definite and sustained conservation practices in an effort by the elderly consumer to cut electricity bills.

Are these post-1970 trends an anomaly, caused by temporary economic depression, federal policies, the Arab oil embargo? We know of no one who has extensively studied the energy supply situation, inside or outside of government, the utility industry, the energy industry, or the environmental movement, who would argue that the real cost of electricity in the future will be cheaper than it is today. We know of no authority who contends the energy shortage is a short-term oddity. We know of no demographer who believes the population of the United States and world is not going to rise, putting further strains on our resource supply systems. The cost of electricity "bottomed out" in 1968, the same year domestic oil and gas production "peaked;" few expect oil and gas to be primary fuels after the 1990's, fewer still expect coal- or nuclear-generated electricity to be anything less than two or three times more expensive than current electricity. The price of electricity is universally expected to rise much faster than the consumer's ability to pay for it, and the result will be (i) conservation, or (ii) a sharp reduction in personal standards of living as electricity costs consume more and more of real income, reducing buying power in other areas.

The expected reduction in commercial and industrial demand should be even greater than in residential demand. The commercial or industrial user has every economic incentive to lower electricity costs or look for alternative sources of energy in order to reduce the price of the products. If they don't, price elasticity will apply to their products as well!

Is it better to go ahead and build new generating capacity anyway, just to be on the safe side? Building generating capacity which will not be immediately utilized is not only not "safe," it may be disastrously expensive. Portland General Electric Company explains:



> If a company. . .overestimates how much its customers will use and consequently builds more new facilities than will be used immediately, the company will have extremely expensive facilities and equipment standing idle for a long period of time and may go bankrupt.[127]

Komanoff and others conclude that it is much cheaper to delay construction of a generating plant than to bring it on line before it is needed. And utility rate economist Dr. Charles Cicchetti recently testified that the utility industry "still seems unwilling to accept the price elasticity argument and to protect itself."[128]

What will happen if PSO builds Black Fox 1 and 2 but their projected customer demand growth doesn't materialize? In that case, each customer would have to bear more of the cost. As cost increases, demand falls off at an even greater rate, causing greater cost increases and greater demand decreases. There is probably a limit to how far demand will decrease in response to rising cost, but the previously-cited study by the Oklahoma Coalition for Older People indicates that residential demand would decrease by 50% or more before slowing its decline. Long-run reductions in demand could be even greater if conservation measures are systematized and applied comprehensively. The above scenario, far from being hypothetical, is currently taking place in many East Coast areas where utilities have applied for rate increases due to reduced revenues caused by falling electricity demand.

The fixed costs--those costs which must be paid regardless of plant output--of the Black Fox plants is around 75% of the total costs. If demand drops much below what PSO projects--as every indication is that it will--then PSO runs the risk of not getting back its nuclear plant costs: $900 million or more in capital costs at 20% fixed charge per year plus all fixed operating and fueling charges.

(c) What are the alternatives? We conclude that there is substantial reason to believe the Black Fox plants will hurt the economy of Northeastern Oklahoma. The degree of financial pressure caused by the high fixed costs of the Black Fox plants will mean higher electric bills, falling electricity demand, decreased financial resources which can be applied to other areas of Northeastern Oklahoma's economy.

Utilities build for peak demand but receive their revenues from total usage, and this in itself will cause problems. If, as PSO projects, peak demand grows at 7.4%/year while total usage grows at 6.2%/year, the difference will add up to an astounding amount of generating capacity which will stand idle all but a few "peak" days in the year--but which PSO's customers will have to pay for nonetheless. The temporary solution is to sell excess capacity to other utilities, but a large surplus may not have an assured market. Thus the first alternative is to levelize peak demand, which analysts David Goldstein and Arthur Rosenfield suggest may be done by diverting only 1% of the time and dollars now invested in new generating capacity toward such electricity-saving measures as better insulation, more efficient appliances, solar heaing and cooling during peak

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periods, and so on.[129]

The large Black Fox nuclear units are an inflexible choice, adding 1,409 megawatts of capacity and a high fixed charge rate to the PSO system. Building smaller coal-fired units, which have lower fixed costs, would give much more flexibility in responding to demand by allowing cancellation of later units if demand doesn't materialize and by shifting the costs from fixed capital to more variable fuel charges.

Finally, PSO (and the Oklahoma Corporation Commission) could aid in bringing about levelized electricity usage by re-arranging their rate structure, which at present offers lower unit rates as usage increases. This encourages a continuing gap between peak usage and average usage. If rates increased along with consumption, peak usage could be discouraged, as well as wasteful use of electricity by large consumers which necessitates costly construction of new generating facilities and by smaller consumers whose rates would go up after a certain base consumption (say, 600 kWhe). This pricing scheme would more accurately reflect the economics of energy supply: increasing cost and increasing inelasticity of supply.

(3) Net Energy

One aspect often overlooked in the debate over future electricity demand is the degree to which the electrical industry itself, by its need for large increments of energy, contributes to that demand. Construction and operation of a large power plant, and the mining, processing, and transporting of fuel, requires a great deal of energy. Uranium enrichment alone, for an industry that supplies only 8.5% of the nation's electricity, consumes 2-3% of our electricity in the process. Although such "net energy" calculations are necessarily rough, they indicate that both nuclear and coal plants spend the first 10 years of their operating lives simply paying back the energy used to maintain them.[130] Thus an energy conservation program will tend to build on itself as the need for installing energy-consuming new generating capacity is reduced.

The best general estimate is that each kilowatt of installed nuclear generating capacity will cost 1,000 kWhe to manufacture, transport, and construct. Thus the Black Fox plants would require about 2.44 billion kilowatt-hours of electricity to construct. We assume that around 75% of this power would be consumed within the PSO service area over the 8 years of construction of the Black Fox plants--in direct electricity; in electricity for refining gasoline to run construction equipment; in reciprocal agreement with Tennessee Valley Authority, whose electricity powers several uranium enrichment plants; and so on --which means around 1.8 billion kWhe spread over 8 years of construction from 1978 to 1986. Most net energy sources would regard this figure as conservative.[131]

Data from PSO's Environmental Report indicate that PSO expects total electricity demand



from all sectors to increase 9.582 billion kWhe between 1978 and 1986, a high rate of growth. But this is not the whole picture. More than 40% of PSO's electricity sales are currently to utilities and customers outside its service area--a use of otherwise idle generating capacity during non-peak periods. Using only the demand within PSO's service area, 7.3 billion kWhe in 1975, and projecting it at 6.2%/year increase, means that real demand will increase only 5.4 billion kWhe between 1978 and 1986--even assuming a high rate of growth. Using a more reasonable 5.6%/year climb (which still doesn't adequately account for conservation in response to rising price), total in-service area demand growth would be only 4.7 billion kWhe from 1978 to 1986.[132]

Power to build the Black Fox plants alone, then, accounts for fully 33% of the growth in overall demand within PSO's service area at 6.2%/year growth, and 38% of the total increase at 5.6%/year growth, between 1978 and 1986!

PSO also plans to add some coal generating capacity in that period. Coal plants do not fare appreciably better than nuclear in terms of net energy, requiring about 70% as much energy to construct. It is a fair assumption, then, that the electricity used to build new generating capacity between 1978 and 1986 accounts for something more than 35% of total projected growth in demand at 6.2% annual growth and 40% at 5.6%/year increase; more than 2 billion kWhe for coal and nuclear additions combined. Only slightly smaller increases due to power plant construction would be added to peak demand growth, unless power plant construction is stopped during peak demand periods.[133]

It must be re-emphasized that net energy calculations are rough, but the figures used here are quite conservative and do not include energy costs for transmission lines and equipment, increased staffing, energy costs associated with building new facilities for the large construction force, and other energy-consuming activities which will result from constructing major generating facilities. Nor do we include the energy supplied by other utilities to manufacture reactor components for PSO in their service areas. The University of Illinois' Center for Advanced Computation did attempt such comprehensive calculations, however, and arrived at a rather pessimistic conclusion:

> Using extremely conservative assumptions concerning the number of new nuclear power plants from 1975 to 1985, ie. 10 new plants in 1975, accelerating by one per year to 20 new plants started in 1985, the total net national energy debt by 1985 will be 96 billion kilowatt-hours. With respect to Project Independence, a nuclear program may be a heat sink.[134]

That is, an energy-consuming rather than an energy-producing activity within that period. The net energy analysis we have attempted tends to show that an energy conservation program in PSO's service area would start out with a significant advantage: for each 2 units of energy saved by such a program, an additional 1 unit "bonus" would be saved because it would no longer be needed to build new generating capacity.

(4) PSO's Generating Capacity

How much new generating capacity, then, will PSO actually need to be assured of meeting its needs? Several immediate complications are present. For example, all of PSO's current generating units are gas- and oil-fired, meaning that by the end of the century all of this capacity will probably need to be replaced by a different energy source. For another, if PSO does not build the Black Fox plants, the price of electricity to PSO's customers will not rise so precipitately and price-induced conservation will not be so great.

Taking these and other complications into account, we see no reason to dispute PSO's prediction that real electricity rates will rise 39% by 1980 and 75% by 1985 (before inflation), since increases in the cost of fuel and replacement of in-place generating equipment alone will probably force such an increase. As pointed out earlier, this cost increase is around twice the rate of increase expected for family income, at best, and means that the average electricity bill will rise 37% relative to family income, from 1.6% to 2.2%.

We also assume that this relative increase in electricity rates will accumulate at 3.7%/year from 1975 to 1985, and that short-run price elasticity will be -.3 for all sectors (that is, a 3.7% increase in real price will cause a 1.1% drop in consumption) and that long-run price elasticity will be -1.0 for the residential sector, -1.2 for the commercial sector, and -2.0 for the industrial sector. Long-run price elasticity response will not begin to show up until 1981. More complicated calculations may not be feasible.

Under these assumptions per-customer consumption will fall 1.1%/year until 1981, after which it will fall 3.7%/year in the residential sector, 4.4%/year in the commercial sector, and 7.4%/year in the industrial sector. These trends are counterbalanced by an assumed 2.3%/year constant growth in PSO's customers, a high estimate.

Thus population will increase by 25% between now and 1985 while per-customer usage will decline 23% by 1985 (1.1%/year to 1981 and 3.7%/year thereafter) in the residential sector, 26% in the commercial sector, and 41% in the industrial sector. Apportioning these declines based on each sector's share of the market--residential 39%, commercial 30%, industrial 31%--the overall decline per customer is 30%. Thus PSO should experience a 5% drop in overall consumption between 1975 and 1985 based on price elasticity alone.

Peak load is harder to calculate because it depends to a large degree on the weather. Energy conservation measures, whether price-enforced or by comprehensive program, should work to slow down peak demand growth. PSO's data indicates the maximum peak load is around three times the average daily load, and we assume--without conservation measures applied comprehensively--that this ratio will continue. Thus some decline in peak load may be anticipated as well.



We conclude, based on experienced price elasticity, that electricity consumption within PSO's system will grow at a decreasing rate until 1980 or 1981, then decline at a somewhat more rapid rate. The overall decline in consumption should be about 5% by 1985, relative to 1975, depending on how much the real price of electricity increases. Peak demand will be more erratic, rising more rapidly than total demand until the early 1980's and then leveling off afterward and perhaps even declining, depending on price, conservation measures, and weather.

PSO is in no danger of short capacity in any immediate sense. Current generating capability--3 million kilowatts--could supply more than twice as much electricity as was sold within PSO's system in 1975 even if only run at 65% of capacity and could easily handle a 15% growth in peak demand without danger of brownout.* An additional 900,000 kilowatts of coal-fired capacity is already ordered and scheduled to go on line in 1980, which will be sufficient to manage a 45% growth in peak demand over 1975 levels. Last year's in-system peak demand was only 2.07 million kilowatts, and PSO's margin of capability was so great that it could support "temporary sales to other systems" even during periods of peak demand within its own system! The result was that PSO sold 4.87 billion kWhe to other systems, 40% of total sales. With this margin, PSO's generating capability should be more than adequate at least until the mid-1990's even if no system additions are made after 1980.

The alternative of 7.4%/year growth through the year 2000 would require installation of 17 million new kilowatts of generating capacity, nearly six times PSO's current capability. This level of growth is not possible within economic constraints which now prevail and would cause a rapid decline in area standards of living as an increasing share of income is sunk into purchasing electricity. Energy conservation is thus not only feasible but vital to preserving financial resources for other economic tasks.

(5) Energy Conservation

We realize that our forecast of a slight decline in electricity consumption in PSO's system in the next decade is at odds with official estimates, which predict growth in consumption will be at least 4.9%/year. Yet our estimates correlate well not only with price elasticity studies elsewhere in the country but also with a remarkably successful energy conservation program implemented in Los Angeles.

During the oil embargo of 1973-74 Los Angeles' municipal power department was faced with a worsening shortage of low-sulphur oil for its generating units, and the city was forced

* Since there are 8,760 hours in a year, one kilowatt of capacity run 100% of the time could generate 8,760 kilowatt-hours per year. Thus 3 million kilowatts of capacity could generate over 26 billion kWhe per year at 100% capacity factor; at 65% capacity factor, they could generate 3,000,000 x 8,760 x .65, or 17 billion kWhe/year. A margin of 15% between peak demand and system capability is considered adequate to avoid a brownout; OG&E's margin is currently 19%.



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to institute a series of energy conservation measures on a broad front. The city government set a goal of 12% reduction in power usage. The program was implemented on 13 December 1973, and within four days electricity consumption dropped 11%. By the end of the shortage four months later residential consumption had dropped 18%, industrial 10%, and commercial 30%, for an overall reduction in electricity usage of 17%. Conservation measures have become an ingrained way of life in Los Angeles, with an overall 14% reduction continued after the program ended, even though the summer of 1974 was hotter than 1973's.

The Los Angeles energy conservation program, far from achieving healthy reductions in energy use through years of careful study and planning, was drafted by a nine-member committee of business, labor, and city government representatives in only six days and put into effect only days after that. Many of the recommended conservation measures are familiar and seem almost rudimentary compared to what could be achieved with a carefully planned, phased, co-ordinated long-term conservation program:

- Eliminating unnecessary lighting by turning off unused lights, maintaining security lighting only after duty hours, and reducing hall lighting.
- Turning off displays and scenic lighting.
- Turn off equipment when not in use.
- Reducing room temperatures to 68° and reducing hot-water temperatures.
- Staggering use of high-energy equipment.
- Eliminating heating in unused buildings.
- Custodial services during duty hours.

Various county government buildings showed electricity and natural gas usage reductions of 35-67% by implementation of measures to reduce excessive lighting and air conditioning and to co-ordinate building use. A Rand Corporation study of the program observed:

> Most of DWP's [the Los Angeles Department of Water and Power] customers said that the plan forced them to adopt new habits, but that it allowed them to maintain a variety of energy uses they considered vital. It also produced economic savings in the cost of electricity (despite rate increases), and the savings on light bulbs and fixtures mounted up remarkably. . .
>
> The continued conservation suggests both that the cutbacks did not affect vital functions or services and that the economics of higher power rates was working, impressions confirmed by the and survey. . .
>
> Almost without exception, the establishments in the survey reported that the ordinance placed no economic hardship on their business.[135]

Contrary to predictions, not one job loss was attributed to the program. Substantial economic savings, however, were reported. One bank, for example, retrofit its air conditioning system and cut kWhe consumption 64%, paying all its retrofitting expenses back in two and a half months.

The overall drop in U.S. electricity consumption during the oil embargo, without conservation programs, was 5%. Various institutional studies confirm that planned programs can complement price-enforced reductions in consumption with a great deal of success. A conservation program at Ohio State University cut electricity demand 31% and natural gas consumption 63%, with a payback period averaging 8 months. Closer to home, a University of Oklahoma program reduced its total energy demand by 15% using adjustments of



thermostats, reduced hot water heating, turning off air conditioners and lights when not in use, and decreased building usage during hot parts of the day. Examples of large cuts in energy use with even minimal planning are too numerous to summarize here.[136]

Peak demand levels are in many ways easier to reduce than total demand since peak consumption is more capricious. Peak demand will be reduced not only by measures aimed at cutting total demand, but also by specific measures which focus on peak load--installing timers on refrigerators, for example, so that a block of ice is frozen during the night and the unit is shut off in the daytime. Electricity rates may be adjusted to allow bargain prices for off-peak usage, as is already done in Vermont and, to some extent, by PSO. Substitution of more efficient, competitively-priced, air conditioning units will effect enormous cuts on peak load and total consumption. In all cases, saving a kilowatt of generating capacity will cost only a fraction of installing it.

Will energy conservation, as is often alleged, cut economic growth and cause unemployment? The one-less-barrel-of-oil-consumed-means-one-less-job assertion has wide emotional appeal to uninformed circles, but no basis in fact. We now have the accumulated evidence of not only conservation experience but also a stack of studies which would fill a small library, whose conclusions are summarized in Appendix 3, which found that planned conservation will "result in cost savings to consumers, no sacrifice in well-being, greater employment, and lower electric rates than a scenario of rapid construction of nuclear plants," according to a representative opinion from the Lawrence Berkeley Laboratory in California.[137] Or the Ford Foundation Project:

> Our adaptation to a less energy-intensive economy would not reduce employment; in fact, it would result in a slight increase in demand for labor. . . Other Project-sponsored studies also support the conclusion that we can safely uncouple energy and economic growth rates.

Or the AFL-CIO:

> A widely held myth says a reduction in energy consumption, through rationing or any other means, would halt economic growth and unemployment would increase from 400,000 to over 1 million. But the best evidence indicates there is no merit in these assertions.

It is difficult, in fact, to find any scientific evidence to the contrary. While we have focused here on energy conservation programs already implemented and successful, the general body of knowledge, acquired largely by conservative institutions and abstracted in Appendix 3, holds that the potential for energy conservation is far greater than anything achieved so far.

Oklahoma stands 13th in the nation in energy consumption per capita. Beside the conservation achieved by Los Angeles and numerous institutional programs--again, programs implemented for the most part on short lead times and with minimal planning or co-ordination--it would seem ridiculously simple to hold growth in electricity consumption in PSO's service area to 45% in peak demand and as much as 300% in total demand before the year 2000. A net reduction is easily possible with few economic adjustments. The alternative to holding electricity consumption within the limits stated above is to build the Black Fox plants--at a cost, even accepting all of PSO's understated assumptions, of at least $10,000 to $15,000 per customer in PSO's system.

No one should pretend that it is PSO's responsibility to see that its customers conserve electricity. That isn't part of their charter. The responsibility lies with the Oklahoma consumer and voter to see that energy conservation programs are implemented as a matter of public, private, and individual policy. We can cut wasteful usage now, eliminate whatever need now exists for new generating plants, save enormous amounts of capital, or we can wait until the price of electricity forces us to cut back after the plants are built and the money spent. The conservative American Institute of Architects perhaps summarized the choice best:

> We are now investing vast quantities of increasingly scarce capital resources in strategies which have less potential, less certainty, and longer-delayed payoffs than the proposed alternative strategy emphasizing a national program of energy-efficient buildings. . . The decision is not whether to modify functional demand or behavior or the level of comfort; it is whether to invest capital to waste energy or to utilize that same capital to conserve energy.[138]

(6) Solar Energy Systems

Present-generation solar installations are best applied to (a) heating and cooling, and hot water supply, and (b) supplying peak power demands. The reasons are obvious. Solar energy is of low intensity and best used for low-quality energy supply, which presently constitutes 70% of our total energy demand. And the sun supplies power most efficiently in the summer daytime when radiation is direct, fortunately when peak power demand is likely to occur. We can do little more here than summarize the potential of solar energy and point out that its applications are here and now as well as 20 years in the future. More specific recommendations will have to wait for a later report.

The National Science Foundation, in the most definitive solar energy study to date, found "no technical or economic barriers" to the immediate, widespread use of solar heating systems. NSF Director Dr. H. Guyford Stever delivered the Foundation's testimony to Congress regarding solar-generated electricity:

> Our assessments indicate that single-crystal silicon solar photovoltaic conversion technology could be developed into a practical power system ready for wide-scale national application by the mid 1980's. The solar arrays for this system may cost less than $500 per peak kWe.
>
> Our assessments also indicate that power sources incorporating even more advanced photovoltaic conversion technologies could be adopted to wide scale terrestrial applications by the end of the century. These power sources, which would use solar arrays with projected cost as low as $100 per peak kWe, would utilize thin film cells, such as those fabricated from Si or CdS/$Cu_2S$.

Dr. Paul Rappaport, RCA's Director of Process and Applied Materials Research Laboratory, agreed, noting that solar electricity costs would be 50 mills/kWhe by 1985 at a proposed research expenditure of $25 million--5% of proposed government nuclear research costs,



not counting nuclear fuel cycle subsidies.[139]

Dr. Bruce Chalmers, of Harvard University's Division of Engineering and Applied Physics, observed:

> The cost of the installation for nuclear or fossil-fuel generating stations is only part of the cost; fuel, maintenance, and obsolescence must also be paid for. A photovoltaic system uses no fuel, and the absence of moving parts minimizes maintenance costs and maximizes life expectancy. . . It should be remembered that in those parts of the country that have the most sunshine [such as Oklahoma] the heaviest demand for electricity comes when the sun is shining, because the air-conditioning load is superimposed on the industrial and commercial demand. During those periods the output of a solar generating plant would be close to four kilowatts for every $2,000 worth of installation. Since that peak load must be provided by one means or another, the photovoltaic option may be the most economical.[140]

While central-station generation of electricity is not the best use for solar energy, indications are that it will soon be competitive for peak-power daytime generation, especially in a system such as PSO's where the gap between peak and average load is so great. At $2,000/kWe, with no fuel and minimal maintenance costs, even base-load generation through photovoltaic cells may soon be competitive with low-cost coal stations.

Solar-operated pumps may also be used to recycle water back up to a reservoir for re-use in a hydroelectric generating station such as those operated by Grand River Dam Authority. Normally such pumped storage systems are a net energy loss, but who cares when the energy is free?

The best use of solar energy is currently on individual buildings. Chalmers and others estimate that a home solar electricity system could supply more than 8,700 kWhe per year (total residential use is only 9,000 kWhe/year) at a total cost of $3,000, with the utility system as a back-up to supply individual peak loads. If such a system were paid off in ten years at a 12% fixed charge rate, monthly costs would be only $30 and the system as a whole would cost about 70 mills/kWhe for 60 years.[141]

Technically-proven solar applications are primarily in individual hot water and space heating and cooling areas. Tens of thousands of solar collectors were installed on houses in the South and Southwest in the 1930's, and solar energy is in widespread use in Israel today. Flat-plate rooftop or ground collectors capable of supplying about 70% of space heating and hot water needs for an average home, 50% of total energy needs, currently cost around $3.50 per square foot--$8,000 to $10,000 for the total system, according to a survey of solar experts by the New York Times.[142] Mass production may bring that total to $5,000 per house or lower. A Tulsa architectural firm is currently building a 100% solar heating and cooling system for a commercial building for $0,000.

Solar heating systems would not, by themselves, appreciably affect summertime peak demand. Fortunately, however, solar hot water heating systems and air conditioning additions may be run from the same flat-plate collector, and these would have a strong



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mitigating effect on peak electricity load.

Wind generation of electricity is not as promising in terms of reducing peak load since there is no guarantee the wind will be blowing at times of peak demand. However, wind-generated electricity may be competitive with other sources as the following studies indicate:

| Study[143] | Capital Costs (1975 dollars) With Storage | Capital Costs (1975 dollars) Without Storage | Total Costs |
|---|---|---|---|
| Federal Energy Administration | $500/kWe | $250/kWe | 33-60 mills/kWhe |
| Mitre Corporation | $700-900/kWe | $500/kWe | 20-38 mills/kWhe |
| University of Oklahoma | | $150-200/kWe | 20-50 mills/kWhe |

The Federal Energy Administration states:

> Wind energy systems. . .should be economically viable within a few years. If the aerodynamic technology developed over the last thirty years were applied, the system costs could be dramatically reduced and market applications would be greatly increased.[143]

There is probably no state as favorably situated to take advantage of solar and wind energy systems as Oklahoma. Combinations of these systems may prove feasible for total home self-sufficiency, since it is a rare day in Oklahoma when both the sun and wind are absent.

While technical and economic barriers to solar energy are minimal, widespread use of home collector systems will require a measure of institutional change. The capital in the power system will be owned in this case not by the utility but by individual homes and businesses, and the individual owner may sell the energy system as added equity along with the property. Viewed over the 60-year life of most solar energy systems, the problems seem manifestly simpler than those involved in supplying an equivalent amount of power through a central-station utility: there would be less capital concentrated in the utility sector, negligible air, water, or thermal pollution, no fuel supply or transportation bottlenecks, none of the uncertainty entailed in low-grade or imported fuels, more domestic capital available since profits are not siphoned off to out-of-state (or foreign) utility investors, greater local employment, less chance of widespread power outages, lower electricity bills, and no need for five-foot thick environmental impact reports. There would also be possibilities for substantial savings to homeowners who installed their own solar collectors.

The principal barrier now is financing authority, which may be arranged on a large scale by appropriate public policy. It now seems inevitable that federal and state incentives will be provided for installation of solar/wind systems and energy conservation measures. The problem of utility stand-by rates must still be resolved. And finally, federal research appropriation imbalance will have to be reversed: ERDA continues to spend five times as much research money on the nuclear breeder reactor while admitting that solar energy will supply three times as much energy as the breeder by the year 2000.[144] And



the Federal Energy Administration estimates that a solar energy program would create 2½ times as many jobs as a similar commitment to nuclear energy, a projection confirmed by the National Committee of American Consulting Engineers' Council.[145] Co-ordination of solar and energy conservation programs seems the best prospect for meeting Northeastern Oklahoma's energy needs in both the short and long term.

E. Recommendations

Five years ago nuclear power looked like the wave of the future. It was at that time that PSO and its consultants calculated the costs of nuclear plants compared to those of coal and other alternatives. Nuclear cost estimates were based not on the actual operating performance of nuclear plants, but on the optimism shared by government and industry that the sluggish fuel use, frequent shutdowns, and low capacity factors of nuclear plants were readily solvable; that uranium was abundant, reprocessing of spent fuel imminent, and breeder reactors just around the corner.

Five years has seen no real improvement in nuclear performance in any area and a real and growing deterioration in nuclear economics. The future economics of nuclear energy, in relation to its alternatives, are not so much in doubt. Mitchell Hutchins of New York, with an investor's eye on the future, sees the "nuclear industry kaleidoscope coming together," and the picture is not a bright one. "The record of nuclear power technological competency," says Mitchell Hutchins, "is strewn with promises broken, promises broken."[146]

Public opposition, however vocal and determined, has not appreciably affected nuclear power development. The federal government is hardly to blame for nuclear power troubles; without its massive aid, nuclear power would be dead tomorrow. The real problem of nuclear energy is one of technical and economic pigeons coming home to roost. Whatever external damage is being done to nuclear power is occurring at exactly those few points where the free enterprise system is allowed to leave its mark.

If nuclear energy represented a viable technical and economic choice, the argument that a diversity of fuels is needed to solve the national energy shortage would be a strong one. If that argument has any validity, however, and we believe it does not, then it should be applied on a national basis, not a local one. Nuclear energy is not economically competitive in Oklahoma. Oklahoma is favorably situated for western coal and is uniquely suited, more so than anywhere else in the nation, to take advantage of solar/wind energy sources.

Concerns over nuclear safety and radioactive legacy are real, and the authors of this report share them. However, we haven't quoted nuclear critics to substantiate our case; the mass of documentation in this report is from nuclear scientists and federal agencies which have vigorously promoted nuclear power, as well as reputable business, utility, and investor sources. Their disillusion with the once-shining atomic star is evident.

For PSO to build the Black Fox plants, doubling or tripling its capitalization and indebtedness in short order, is unwise in the extreme. The nuclear industry and fuel cycle may stabilize in coming years, although this seems very unlikely. If not, their loss need not be our loss. There is no certainty now but billions of dollars in front-end costs for a technology which needs to solve myriad fundamental problems to deliver its promise. There are alternatives, all expensive, but all reliable. We recommend:

(a) Immediate cancellation of the Black Fox plants.

(b) Substitution, if demand growth warrants by 1978, of three 600-MWe or 650-MWe coal-fired plants with appropriate pollution control equipment, later units to be cancelled if electricity demand slackens.

(c) Implementation of considered conservation programs designed to reduce energy use and increase efficiency of use within PSO's service area, either as a matter of public policy (best) or through private initiative to the extent these are effective.

(d) Development, as a matter of public and private policy, of renewable solar energy sources which may be installed as individual property (best) or as central generation units.

(e) Participation by citizens in all phases of energy evaluation and policy formation. Site certification of power facilities, as is now done in thirty other states, is needed to:

(i) establish the need for new generating facilities,

(ii) establish that the proposed facility is the best alternative,

(iii) assure that the proposed facility will be economical, safe, and may reasonably be expected to operate as designed,

(iv) provide a means of public review and hearings in advance of construction, and

(v) require that those seeking to construct such a facility post appropriate bond to assure that long-term effects of the facility are not passed on to future generations.

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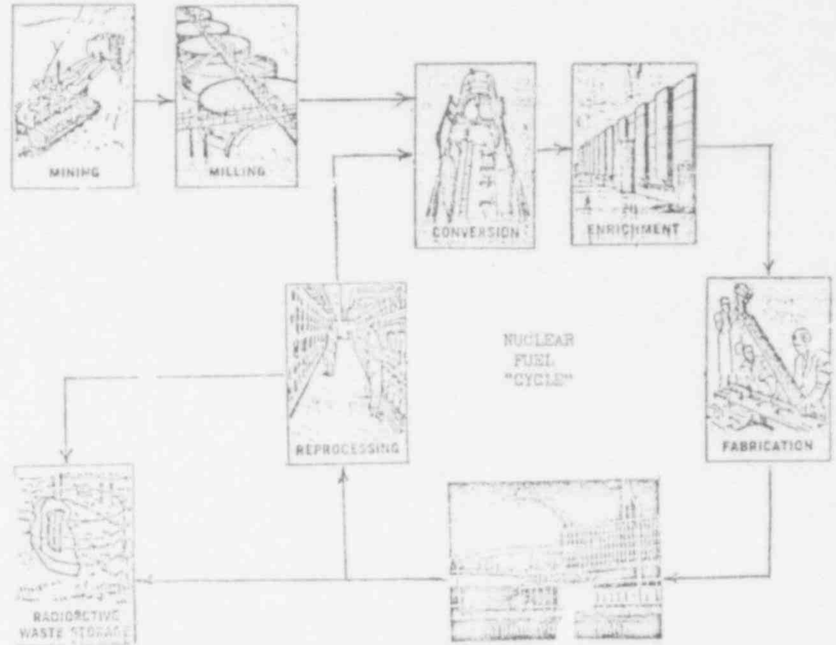
APPENDIX 1. DERIVATION OF NUCLEAR FUEL QUANTITIES, TABLE 2




The methodology and calculations used to predict annual nuclear fuel cycle costs in Table 2 are as follows:

(a) The first step in calculating nuclear fuel costs is to estimate how much fuel the reactor will use in one year's time. We have assumed that the Black Fox stations will generate, on the average, 55% of the electricity they are capable of generating:

| | |
|---|---|
| 2,300 | megawatts of electrical capacity |
| x 365 | days/year |
| 839,500 | megawatt-days/year of electrical capacity |
| x 0.55 | capacity factor |
| 461,725 | megawatt-days/year of electricity actually generated |

A nuclear power plant converts heat energy to electrical energy at a rate of 1/0.325, which means that 32.5% of the thermal power produced by the uranium fuel is converted to electrical power, and 67.5% escapes from the plant as waste heat. Enough fuel must be loaded into the reactor to produce:

| | |
|---|---|
| 461,725 | megawatt-days/year of electricity |
| ÷ 0.325 | megawatt-days of electricity per megawatt-day (thermal) |
| 1,420,692 | megawatt-days (thermal) generated/year |



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An optimistic projection is that nuclear plants will, in the future, obtain approximately 25,000 megawatt-days (thermal) from each metric ton (equal to 2,205 pounds, or 1,000 kilograms) of enriched uranium fuel loaded into the reactor. To determine the number of metric tons needed to fuel the Black Fox stations for one year:

1,420,692 megawatt-days (thermal) generated/year
÷ 25,000 megawatt-days (thermal)/metric ton uranium fuel
56.827 metric tons of uranium fuel/year

Of this amount, the reactor will "burn" only about 3% of the fuel. The reason is that only 2.6% of the fuel is fissionable, heat-producing $U_{235}$; the remainder is $U_{238}$, and a small amount of $U_{238}$ is converted to other fission products during the time in the reactor. Almost all of the $U_{235}$ is burned, and the spent fuel removed from the reactor is reduced from 2.6% to 0.85% $U_{235}$. This spent fuel may be recycled and re-enriched for use as fuel again, and the amount available for recycling is:

56.827 metric tons of uranium fuel/year
x 1,000 kilograms/metric ton
56,827 kilograms of uranium fuel/year
- 1,704 kilograms of uranium fuel "burned" in the reactor (3%)
55,123 kilograms of "spent" uranium fuel available for reprocessing

About 1% of this total is lost in normal reprocessing and storage operations, and another 0.3% is lost in converting the spent fuel to uranium hexaflouride to be used in the enrichment plant. Thus only 54,408 kilograms of spent fuel actually reaches the enrichment plant.

(b) Uranium enrichment is a complicated process. A boiling-water reactor normally uses fuel whose content is 2.6% fissionable $U_{235}$, but spent uranium fuel is only 0.85% $U_{235}$. The gaseous diffusion enrichment process slowly separates the $U_{238}$ and $U_{236}$ isotopes from the $U_{235}$ in a series of stages. The energy required to do this is measured in "separative work units" (SWU's) and varies according to three factors:

P = the degree of $U_{235}$ concentration desired (in this case, 2.6%)

F = the $U_{235}$ content of the uranium fed into the enrichment plant (in this case, 0.85% in the spent fuel), and

W = the $U_{235}$ content of the waste uranium "tails" left over after the enrichment process (currently set by the government at 0.30%).

Dr. Raymond L. Murray, professor of nuclear engineering at the University of North Carolina and nuclear textbook author, states that the quantity of enriched uranium product obtained may be calculated by the following formula:[147]

$$\frac{P - W}{F - W} = \text{the ratio of uranium feed to enriched uranium product}$$

Substituting the numbers for P, F, and W above:

$$\frac{0.026 - 0.0030}{0.0085 - 0.0030} = 4.18$$

Thus it takes 4.18 kilograms of feed to produce 1 kilogram of enriched fuel product. The amount of enriched fuel which can be obtained from the 54,408 kilograms of spent fuel from the reactor is:



54,408 kilograms of spent fuel available for reprocessing
÷ 4.18 kilograms of feed per 1 kilogram of enriched product
13,016 kilograms of enriched fuel from reprocessing

The cost of uranium enrichment service is based on the number of SWU, which are proportional to the amount of product and the degree of enrichment required. The number of SWU may be calculated from the following table (from Murray's Nuclear Energy):[147]

| Enrichment Desired (percent $U_{235}$) | Separative Work (SWU) per kilogram product |
|---|---|
| 0.711 | 0 |
| 0.8 | 0.104 |
| 1.0 | 0.380 |
| 2.0 | 2.194 |
| 2.6 | 3.461 |
| 3.0 | 4.306 |
| 5.0 | 8.851 |

The spent fuel is already at 0.8% $U_{235}$, so that not as much separative work is required as for natural uranium, which is only 0.711% $U_{235}$. Referring to the table above, each kilogram of 2.6% enriched product will require 3.357 SWU (3.461 - 0.104). The number of SWU required is:

13,016 kilograms of enriched fuel
x 3.357 SWU per kilogram of 2.6% product enriched from 0.8% feed
43,695 SWU

Approximately one-fourth of the Black Fox fuel will come from re-cycled spent fuel--if reprocessing solves its economic and technical problems before 1985.

(c) The remaining uranium fuel for Black Fox must come from natural mined uranium. To calculate this quantity, return to the "Reactor" step in Table 2. The amount of raw uranium feed which must be present at the beginning of the enrichment stage is derived in the following way (working backwards from the "Reactor" stage):

56,827 kilograms of uranium fuel/year
÷ 0.99 allowance for 1% (0.01) normal processing loss
57,445 kilograms of uranium fuel needed for fuel preparation and fabrication stage

Note that 4,323 kilograms, around 7%, is lost in the fuel fabrication and preparation stage but remains available for recycle in the enrichment stage. It makes no difference in the final calculations.

57,445 kilograms of uranium fuel needed for fuel preparation and fabrication stage
- 13,016 kilograms of uranium fuel from reprocessing
44,429 kilograms of uranium fuel enriched from raw uranium

Again using the feed/product enrichment formula in part (b) above, except that this time the feed is 0.711% $U_{235}$ raw uranium:

$$\frac{0.026 - 0.0030}{0.00711 - 0.0030} = 5.596$$

so that 5.596 kilograms of unenriched uranium (in the form of uranium hexaflouride, $UF_6$) must be fed into the enrichment plant in order to obtain 1 kilogram of 2.6% enriched uranium fuel. A total of:



719 298

719 140

44,429 kilograms of uranium fuel enriched from raw uranium
x 5.596 kilograms of feed per 1 kilogram of enriched product
248,624 kilograms of $UF_6$ fed into Enrichment stage

The SWU needed to enrich 0.711% $U_{235}$ raw uranium into 2.6% $U_{235}$ uranium fuel can be taken directly from the table in part (b):

44,429 kilograms of enriched fuel
x 3.461 SWU per kilogram of 2.6% product enriched from 0.711% feed
153,769 SWU

(d) In the conversion to uranium hexaflouride, approximately 0.5% of the original quantity is lost to normal processing losses:

248,624 kilograms of $UF_6$ fed into enrichment stage
÷ 0.995 allowance for 0.5% (0.005) loss in conversion to $UF_6$
249,874 kilograms of raw uranium needed from mining

(e) The raw uranium used above is obtained from natural $U_3O_8$, uranium oxide, often called "yellowcake." It takes 1.179 kilograms of $U_3O_8$ to produce 1 kilogram of pure raw uranium:

249,874 kilograms of raw uranium needed from mining
x 1.179 kilograms of $U_3O_8$ per 1 kilogram of raw uranium
294,601 kilograms of $U_3O_8$

$U_3O_8$ is priced by the pound. There are 2.205 pounds in one kilogram:

294,601 kilograms of $U_3O_8$
x 2.205 pounds per kilogram
649,595 pounds of $U_3O_8$

This final figure is the total annual amount of mined uranium needed to fuel the two Black Fox stations, given previous assumptions.

APPENDIX 2. COAL AND NUCLEAR IMPACTS

The "impact statement" offered below is admittedly superficial but may give some idea of the major problem areas of coal and nuclear fuels:

Labor demand. Coal-fired plants create fewer construction jobs than do nuclear plants but more in operation and fueling. Overall, a coal-fired plant will create about 60% more jobs than a nuclear plant of similar size, although many of the mining jobs would be outside of Oklahoma.

Tax revenues. Utility tax revenues are of little benefit on a general basis since utility customers pay for them in the first place.

Total cost. Using the assumptions outlined for Tables 1 and 4, total kilowatt-hour costs of a low-sulphur coal-fired plant will be 32% cheaper, and a high-sulphur coal-fired plant 10% cheaper, than a nuclear plant, all units scheduled for operation between 1983 and 1986.

Fuel resource commitments. Three 600-MWe low-sulphur coal-fired units will require annual mining of 6.65 million metric tons of ore needed to yield 5.1 million tons of coal. Three 650-MWe high-sulphur coal units will use 5 million tons of ore producing 3.8 million tons of coal each year. Two 1150-MWe nuclear plants supplying the same volume of electricity as the above coal units will need about 250 metric tons of raw uranium per year (assuming reprocessing of $U_{235}$ from spent fuel), requiring the mining of 250,000 tons of uranium ore at concentrations of 1000 parts per million, 500,000 tons of ore at 500 ppm, or 1.25 million tons of ore at concentrations of 200 ppm. Without $U_{235}$ reprocessing, the same nuclear plants would burn 321 tons of uranium per year requiring ore commitments ranging from 321,000 tons (at 1000 ppm) to 1.6 million tons (at 200 ppm). All assumptions are from Tables 2 and 4 and are for 1985 technology. Thus nuclear fuel places less strain on mining and transportation systems as long as high- and intermediate-grade ore remains available.



Mining impact. Strip-mining of coal presents serious environmental hazards, including acid runoff, erosion, loss of agricultural and silvicultural qualities, aesthetic offenses, and stream contamination, yet is less dangerous to workers and generally cheaper than sub-surface mining. Strip-mined terrain has been reclaimed in other countries, most notably West Germany, with near-100% success, although considerable expense may be anticipated. Compliance with mining safety standards has reduced mining injuries and fatalities by a factor of ten or more for both uranium and coal mining. Strip-mining of uranium may prevail in the 1990's if large high-grade ore deposits are not found. More than 100 million tons of radioactive tailings from past and present uranium mining and milling operations remain a hazard in Western states, subject to wind and water erosion as well as unauthorized human use for house construction which have resulted in excessive radiation exposures. If these tailings are not to remain a significant health hazard for centuries, resulting in many thousands of premature deaths (according to Columbia University's Dr. Robert Pohl), an undetermined expense may be anticipated for their covering, disposal, and monitoring.[148]

Air pollution. Coal plants require precipitators to remove fly-ash particulates, and high-sulphur coal additionally necessitates use of stack-gas "scrubbers" to neutralize sulphur oxide pollutants. Assumptions used in Table 4 include large allocations for air pollution controls, and it is generally accepted that emission controls will reduce coal pollutants to negligible levels by 1985. Operating normally, radioactivity releases from nuclear plants are small, but the impact and likelihood of abnormal, large releases are vigorously debated. From the 56 presently operating nuclear plants in the United States there have been around fifteen unplanned releases of radiation per year. Official predictions are that long-term impacts of such planned and unplanned radiation emissions will be small, but again, the state of present knowledge is not sufficient to predict with certainty

Water pollution. Both coal and uranium mining and processing operations present large threats to water quality if not controlled. Thermal emissions from nuclear plants are about 50% higher than those from coal plants generating an equal volume of electricity. Radiation emission impact similar to that for air with regard to uncertainty. Adequate cooling water is not assured in Northeastern Oklahoma for large increments of either coal or nuclear capacity.

Waste disposal. Neither coal nor nuclear waste disposal problems are currently solved or on the verge of solution. Three coal-fired plants of the size evaluated in Table 4 would produce up to 600,000 tons of ash wastes per year which are non-toxic but will require about ten acres of land and proper landfilling to avoid adverse effects. Possible market potential, however, exists for use of coal ash as a filler in road pavement. Nuclear plants, with or without reprocessing, present vastly smaller quantities of vastly more dangerous waste products. Disposal of low-level radioactive wastes is currently primitive and unsatisfactory. High-level radioactive waste disposal technology has not yet been developed and current storage is in surface facilities with an expected life of 20 to 100 years. Some particularly dangerous fission materials remain deadly for tens of thousands of years and, even in small quantities, must be carefully isolated, guarded, and monitored for as long as the hazard remains. No means, either technical or political, now exist for doing this. Attempted disposal in Kansas and New Mexico salt formations has proven unfeasible, and surface storage is not a long-term prospect. Radioactivity leaks from both high-level and low-level storage sites have been frequent, impact unassessed.

Net energy. According to the Oregon Office of Energy Research and Planning and Pacific Power & Light, the thermal energy produced by a coal-fired plant is rough-



719 299

719 141

ly 3.14 times the energy needed to build, operate, and fuel the plant. The same ratio for a nuclear plant, assuming reprocessing and recycling, is considerably better: 5.33. However, coal plants convert around 60% of the energy present in coal in the ground to thermal energy, and 38% of the thermal energy to electricity. Nuclear plants use only 39% of the primary uranium resource in the ground, even assuming recycling of spent fuel, and convert 32% of their thermal energy to electrical energy. Additional data from ERDA and Dr. Howard Odum of the University of Florida, one of the nation's leading net energy authorities, indicate that a nuclear plant will produce over its 30-year lifetime between three and four times as much energy as it consumes. The result seems to be a standoff--a nuclear plant will spend approximately 9 of its 30 years, and a coal plant 11 of its 40 years, simply repaying its energy debt.[149]

Expected plant operating life. The operating experience of c al plants indicates that a lifetime of 40-50 years may be expected. Most coal plants retired earlier than that have been for reasons of obsolescence, not failure, a luxury which high power plant capital costs may not permit in the future. Coal plants are usually amortized for 40 years. A reduced capacity factor will occur toward the end of the plant's life, and pollution control equipment replacement at undetermined intervals is a distinct possibility. Cost assumptions in Table 4 are intended to reflect this added expense. Nuclear plants, originally forecast to operate 40 years, have little operating experience on which to base a judgment, and what experience there is indicates that they will do well to last 30 years. The present generation of nuclear reactors is not performing as e pected. The forced outage rate will increase and the capacity factor steadily fall after the 12th year of operation, based on experience, averaging 40-45%. A total operating life for nuclear plants of longer than 18 years cannot be predicted with confidence, although they are currently amortized over 30 years. Dr. Earl A. Gulbransen, of the Department of Metallurgical and Materials Engineering at the University of Pittsburgh, writes:

> After 25 years of research and development work on the chemical and metallurgical properties of metals and alloys used in nuclear power plants, I have come to the conclusion that the current design and materials cannot give us a safe and well-engineered nuclear power plant. It now appears that there are serious limitations for some of the materials used in nuclear reactors. . . Many of the recent difficulties in the operation of our present nuclear power plants are due to material problems in the reactor, steam generator, and turbine. There appears to be no way to overcome the inherent material problems associated with zirconium alloys and the current design of the reactor. . . No backup or alternative design is available if the present design and materials prove unreliable.[150]

APPENDIX 3. THE POTENTIAL FOR CONSERVATION -- SOME REPRESENTATIVE STUDIES[151]

Th industrial sector can save 10% of its 1972 total consumption with an investment in conservation of $1 billion per year between 1974 and 1978; "these expenditures probably will be economically justifiable with present and projected energy prices. . . projected demand growth [can] be satisfied over the next 5-7 years at reduced total energy use." A $60 investment in saving one kilowatt of energy will offset the need to build a kilowatt of generating capacity at an investment of $400.

- National Petroleum Council, "Potential for Energy Conservation in the United States: 1974-1978; Industrial," 10 September 1974, pp 2-4

The rate of decline of industrial energy consumption per unit of product produced has been declining since 1954 and will accelerate in decline in the future.

- The Conference Board, "Energy Conservation in Manufacturing," 1974, p 2

At an investment of $13 billion between 1975 and 1985, systems may be designed to exchange steam and electricity between industries and utility power plants,



at a savings of over 200 billion kWh of electricity per year and $29 billion in costs.

- Dow Chemical et al, "Energy Industrial Center Study," June 1975, pp 6-11

Mandatory insulation standards, heat pumps leased by the city, discouragement of electrical resistance heating, incentives to promote conservation and solar energy where feasible, would expand Seattle's electricity supply at a cost of only 0.7¢/kWhe, as opposed to a cost of 2.7¢/kWhe for nuclear supply electricity, with no adverse effect on employment (1975 dollars).

- Seattle City Light, "Energy 1990: Initial Report," vol 1, Summary and Overview, February 1976, ch 7

"Savings on the order of 20 to 30 percent in energy consumption can be realized in a significant part of the industrial sector through the application of existing, economically justifiable techniques."

- U.S. Department of Commerce, "Energy Conservation and the Business Community," undated, p. 4

All four of Texas' most energy-intensive industries would benefit from an "aggressive" energy conservation program. The half-billion dollar investment in conservation "would be competitive with other needs; however, based upon the projected rise in fuel costs in the next five years, 1-3 year payout of capital would be possible." Industries studied account for 90% of Texas' industrial energy use.

- H. William Prengle, Jr., et al, "Potential for Conservation in Industrial Operations in Texas as Measured by: Petroleum Refining, Chemical Manufacturing, Pulp and Paper Production, Metals Production," Governor's Energy Advisory Council, November 1974, p iii

Industrial thermal processes, on-site generation of electricity, increased process efficiency, waste heat recovery, and recycling offer opportunities for significant cost-effective energy conservation in many areas of industry.

- University of Oklahoma, "Energy Alternatives: A Comparative Analysis," May 1975, pp 13-31

Cutting U.S. energy demand to 1.9% per year through the year 2000 will require a capital investment of $400 billion and will not alter lifestyles or the production of goods and services. Such investment will save $700 billion in energy investment for a net savings of $400 billion.

- Ford Foundation Energy Policy Project, "A Time to Choose: America's Energy Future," 1975, pp 14-15, 169-70

Applying "technologies that are either commercial now or are likely to be commercial in the near future" would cut U.S. electricity demand by 33% and total energy demand by 45%, even without change in lifestyles.

- Marc Ross and Robert Williams, report by the Institute for Public Policy Alternatives to the American Physical Society, "Assessing the Potential for Fuel Conservation," July 1975, pp 18, 26

West Germany's steel industry uses 32% less energy per unit of output than does the U.S. steel industry, while its petroleum industry uses 33% less energy and its paper industry 43% less--overall, West Germany uses only 60% of the energy per capita as does the U.S. "Continued economic growth and improvement in the [U.S.] standard of living should be possible without a proportionate increase in energy consumption."

- U.S. Federal Energy Administration, "Comparison of Energy Consumption Between West Germany and the United States, A Summary," quote p 11

In all cases surveyed of saving electricity in industry, conservation is one-half to one-tenth as expensive as investing in new generating capacity.

- George Hatsopoulos, president, Thermo Electron Corporation, testimony to Senate Commerce Committee, 19 June 1975, pp 4, 6

Cutting building lighting levels to reasonable intensity would reduce U.S. total energy demand by 6% in 1980, at minimal expense.

- U.S. Federal Power Commission, "Power Generation: Conservation, Health and Fuel Supply," March 1975, pp 46-47

A 32% reduction in demand for air conditioning, lighting, and space heating in commercial buildings is possible "based on current reasonable technology and cost. They do not reflect the ultimate reduction possible."

- U.S. Federal Energy Administration, Project Independence, "Residential and Commercial Energy Use Patterns 1970-1990," vol 1, November 1974, p 25

Insulation of existing homes will save 9960 kWhe/year/house and pay for itself in one year in New England; 3800 kWhe/year/house and 2.6 years in the Southwest; 1344 kWhe/year/house and 3.3 years in Atlanta; 1490 kWhe/year/house in New York; and 2317 kWhe/year/house and 3.6 years in Minneapolis.

- U.S. Federal Power Commission, "Measures for Reducing Energy Consumption for Homeowners and Renters," March 1975; and David B. Large, "Hidden Waste: The Potential for Conservation," The Conservation Foundation, 1973, p 20

A "vigorous" energy conservation and solar energy program is technically and economically feasible and would eliminate the need for a $2 billion nuclear power plant on Long Island. The nuclear plant would create 16,000 total yearly jobs, while a smaller investment in solar energy and conservation would create 34,000 new jobs.

- Fred Dubin, chairman, National Committee of American Consulting Engineers Council, Electrical World, 1 May 1976

A national program to insulate 4 million homes per year would create 80,000 jobs and save the equivalent of 1. billion barrels of oil in 5 years.

- Ibid

An investment in energy-efficient buildings would be paid back in 10-15 years and would save 12.5 million barrels of oil per day, providing a return of 4% to 13.7%.

- American Institute of Architects, "A Nation of Energy-Efficient Buildings by 1990," 26 February 1975

"American social habits, formed through years of low cost commodities, are going to have to yield to the ways of a conserving society. . . per capita resource usage and goods consumption in the United States will decline in the remaining years of this century."

- Roy A. Lindberg, Richard H. Amagi, Marketing/Management Services Division, National Credit Office, Dun & Bradstreet, "Reclamation 1975-2000: A Key to Economic Survival," November 1974, pp 4, 5

"Conserving energy--by reducing its consumption and making more efficient use of the energy that is consumed--is the only short-term answer to the energy crisis, and must be a major part of the long-term solution as well. . . Over the long term, the need to conserve energy will require fundamental changes in the way Americans live and work, and even where they live and work."

- Oklahoma Energy Advisory Council, "Energy in Oklahoma," Final Report, 1 February 1974, pp 12, 13

"The overall trend of the American economy [has been] to turn to energy consumption rather than human labor when production is increased, a phenomena often called technological unemployment. . . There have been attempts to demonstrate a close correlation between energy use and the size of the GNP. If this were true, the ratio of total energy to dollars of GNP would be the same for all countries. However, there does not appear to be a consistent relationship [but]. . . a variation from 10 to 214 trillion BTU's per dollar GNP. . . many western European countries such as France, Switzerland, and The Netherlands have only one-third the per capita energy consumption of the United States, yet have a similar life style."

- Oregon Office of Energy Research and Planning, Transition, 1 January 1975, pp 109, 25

"The wave of tomorrow in the marketplace is for littler, fewer and better. . . A world where less is better is bound to make for a world, and life too, that is better." - editorial, Forbes, 1 November 1974

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Sept. 1, 1976
3900 Cashion Pl.
Oklahoma City, Okla. 73112

9-9-76

Director, Division of Site Safety and Environmental Analysis
Nuclear Reactor Regulation
Nuclear Regulatory Comm.
Washington D.C., 20555

Dear Sir:

I am submitting these comments on the Draft Environmental Statement on the Black Fox Nuclear Generating Stations, Units 1 and 2 for Public Service of Oklahoma. Docket No. STN 50-556 and 50-557, issued July 1976.

First off, I would like to protest the timing of the release of the Draft Environmental Statement. I am one of the intervenors against the two Black Fox Stations and I didn't recieve my copy until the middle of July, with comments on the report due sometime around Sept. 7. I am sure you are aware that vacations are usually scheduled at this time, and the first week in Sept. is hectic with people getting their kids back in school, etc. I wish I didn't think the timing was deliberate. I gave my only copy to Mr. Mike Malos who was working on the economic aspects of BFS, so had to leave on our three week vacation in August without a copy of this report. Very little time was left to go through the statement and come up with judgments on the contents. I am certain that most officials, businessmen and interested citizens who may want to comment are pretty much in the same kind. However, be that as it may, I will send along my hurridly formulated comments on the report.

In looking over the summary (Table 10.11) I notice the environmental effects of the two 1220 megawatt Boiling Water Reactors (2440 megawatts of generated electricity) will have minor or negligible effects on the environment. You state such beneficial effects as increased payroll, induced expenditures, and tax revenue. This, together with the listed stress on the housing market, is bound to

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increase the pressure of local businessmen and construction workers to build these plants. However, gentlemen, the time if long past when you can claim that two enormous nuclear plants (plus two additional 500 megawatt coal fired ones in the same county) can be built and operated without adverse effects on the environment. I would hope that the final environmental statement will acknowledge the true environmental costs to ourselves and to future generations.

I have before me the latest Gallup Poll on Nuclear Energy, July 22, 1976. In that survey, 45% of those questioned would be against the building of a nuclear plant within five miles of their home, 42% would not be against, with 13% of no opinion. Nationwise, 34% thought present reactors safe enough, 40% were in favor of cutting back operations, with 26% of no opinion. Nuclear energy is introducing a new dimension into the lives of our populace; that dimension is fear. One advantage of living in a democracy has been the freedom from fear. Now, we find that many of us would be fearful of living close to a nuclear reactor. This will become more pronounced as more reactors are put into operation and news items of accidents, leaks, occurences, etc, become more frequent. Although you report that these reactors (BFS) would be 23 miles from downtown Tulsa, they are, in reality, 10 miles from the Tulsa city limits. They are too close to a large metropolitan area, and are much closer to large concentrations of people than the 23 miles to the center of Tulsa suggests.

In case of accidental releases of radiation, such as the recent explosion at Hanford or the discharge of 85,000 gallons of radioactive material from the Vermont Yankee plant to the Connecticut River, there will be increased fear of the long-term effects of this radiation on health. Just as the person, diagnosed with having cancer, always lives in fear of its reappearance, so too the people exposed to accidental releases of radiation. There is the additional fear of passing genetic damage on to one's offspring. In Japan and in Palomares, Spain, people hesitate to marry into a family that has been exposed to nuclear fallout- or, in Spain, to the plutonium (1)



contamination from the accidentally dropped bombs. I am enclosing an article from the Bulletin of the Atomic Scientists, Sept. 1976 that researches the reasons for peoples attitudes and fears in this regard. (2)

As to the radioactive effluents, it is stated that the effects on the public of the radiation exposure is negligible, and to nuclear workers and to construction workers, the effects would be minor. I disagree with these statements. The history of radiation has been of constantly tightening standards because the long-term effects are now beginning to be discovered (i.e. the breast cancer X-ray controversy now in the headlines). (3) In the last two years, the cancer rate in this country increased about 4.2 %- a really epidemic rate. Dr. William Rowe, Assistant Administrator of Radiation Programs, EPA, said in the Feb. 1976, EPA Journal, "At low levels we consider that all exposure to radiation carries some hazard proportional to the dose recieved. The ionizing radiation acts upon the various organs of the body and the cells in the organs to cause changes in the cells that might develop as cancer sites. This can be caused not only by radiation itself but radiation acting with other potential carcinogens in a synergistic manner to possibly cause cancer over a long time period. It may be anyphere from 10 to 20 years from the initiation of the radiation dose till the cancer develops."

I am enclosing an article from the June 1932 issue of Readers Digest of a young woman condemned to death because she had been employed painting radium on watch dials. (4) Tragically, we find so many things out- after the fact. However, with radioactive contaminants, such as plutonium 239, we won't have much chance to correct any mistakes we may make. We are adding so many new elements to our lifestyle and systems that it is impossible to pre- the interrelationship between increased radiation and other carcinogens. Also, in Sept. 1976, Bulletin of the Atomic Scientists, is the report "Toxicity of Plutonium and other Actinides" (5). This article sets forth the theory that continuous doses of low-level radiation can be much more carcinogenic

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than perhaps higher single doses of radiation, since high radiation bursts kills cells, whereas constant low levels only injures them. The article also discusses the concerns over handling and containing plutonium and other actinides safely. The Black Fox reactors will generate about 1000 pounds of plutonium a year. This plutonium will have to be perfectly contained, a seemingly impossible task for mere human beings.

My reading of the Code of Federal Regulations, NRC Part 50, App I states allowable liquid effluents for each reactor to any individual is 3 millirems to whole body or 10 to any organ- for gaseous effluents the limitation is 10 millirads for gamma and 20 for beta radiation. This would allow up to 40 millirads for two reactors in operation which would be close to half the background level for radiation. It is difficult for the citizen to determine just how much radiation is allowed to be released from these plants. EPA has proposed new standards of 25 millirems to the whole body with 75 to the thyroid for any member of the public as a result of releases from facilities of the nuclear fuel cycle. Providing, of course, for variances in case of exceeded limits so as not to interfere with the orderly supply of power. As far as I can tell, allowable releases can still be as high as 500 millirems to members of the public. Even if the allowable limits are enforced, which is hard to do, there is always the possibility/probability of accidental releases of radiation. One doesn't have to read many safety reports to know that this is the case.

While you say that the effects on nuclear workers are minor, you certainly must realize that those workers are part of society and part of the genetic pool. Nuclear workers marry and have children, and their radiation exposure can cause genetic damage in their children or introduce mutations into the genetic pool.(6) The longevity of some radioactive elements and the genetic damage are several of the awesome considerations when radiation is considered. We are causing our children to pay



for our debts in the use and abuse of nuclear power generation. We still haven't investigated the results of low levels of krypton 85 and tritium on biological systems. Nor have we determined whether high power transmission lines might have health effects on the people living or working near the lines.

The environmental report glosses over the problems of radioactive waste storage. Some contain extremely long lived elements such as plutonium 239 with a half life of 24,000 years and iodine 129 with a half life of 17 million. I haven't heard any discussion of one facet of this problem. If the total world supply of petroleum will be depleted in 60 years- what means will we have of shipping, handling, and relocating these wastes. It will take petroleum to do that- even coal will last only something like 400 years. According to Dr. William Rowe (EPA Journal, Feb. 1976), " We have about 85 million gallons of high level waste so far from our weapons program, and we have about 100,000 to 200,000 gallons of waste to date from the nuclear industry." IN addition to this by the year 2000 we will have accumulated 1 billion cubic feet of waste- enough to cover a four-lane highway, one foot deep from coast to coast. Again Dr. Rowe, " By the year 2000, we estimate that the total commitment for waste management will be about 7 billion dollars, which includes some allowance for inflation over this period" For how many thousands of years must future generations be committed to labor and financing for waste management whether they opt for it or not. No nation has, as yet, developed a satisfactory method of storing these wastes. I am enclosing a newspaper clipping in which the European countries are still dumping their radioactive wastes into the Atlantic Ocean.(7) A friend of mine, who taught college courses in geology, opposes nuclear energy because of the radioactive waste problem. She says there is no place on earth which we can say is geophysically stable for long periods of time. Dr. Carlos Dell, who did a study for the AEC on earthquakes, stated in a speech at Critical Mass that all it takes to change the earthquake zone in this country is just a new earthquake. While unlikely in many places, an earthquake can still occur at any place, at any time. Waste

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disposal sites and reactors would certainly exacerbate the effects of natural disasters such as earthquakes, tornadoes, floods, etc. See the enclosed clipping on the Philippines. (8)

Very little is said in the draft statement about thermal pollution and the problem of waste heat. Thermal releases alone will stop us ere long on our exponential rate of energy production. About 2/3 of the output of the two Black Fox plants will be released as waste heat either to the water or to the atmosphere.(9) Oklahoma has been our home for twenty years. In some years, July and August temperatures have climbed over 100 degrees everyday- even to temperatures reaching 110 to 115. Either an increase in the humidity or the temperature would increase suffering and possibly even cause death to persons or livestock exposed to this heat. It could certainly cause fish kills in the affected waters. Oklahoma is a land of extremes and periodic cycles of drought- consider the dust bowl. We also have extreme weather conditions such as electrical storms, tornadoes (we have one of the highest instances of tornadoes in the country) hailstorms and downpours causing flash-flooding. While we were in Colorado in August, Big Thompson had a flood- estimated to happen once in 500 years- causing a loss of 120 to 200 lives. You have only planned for a 50 year drought for the Verdigris. This is inadequate and extremely risky.

A loss of cooling water could be very critical for the BWR's. It seems to me that the safety of the plants is very vulnerable to any phenomenon that could block the inflow of water from the Verdigris, such as a natural block perhaps caused by a turbulent flood or blockage due to sabotage.

Our red clay is such that it bakes bricklike in the hot dry weather. This causes extreme runoff in hard rains and flash flooding, causing a constant danger of flash flooding in the state.



The expansion and contraction of our clay also causes cracking of even the best built of structures eventually. This could cause trouble with underground piping, cracks in buildings, etc.

Since atomic plants put out 50% more thermal pollution than fossil fuel ones, Black Fox will require huge amounts of cooling water. PSO has requested 45% of Tulsa's commitment of Oologah's water, this, in addition to the 31,000 acre feet from that reservoir that PSO has already reserved. If the city of Tulsa grants PSO this water, municipal water users will have to find water somewhere else, at a greatly increased cost. (10)

The waste heat released to the atmosphere could also increase the incidence of turbulent weather, fog, icing, inversions and possibly climate changes and tornado incidence.

While it is difficult to evaluate the effects of a severe tornado on a nuclear plant and its ancillary operations, there is always the possibility of missile penetration, or theorsen causing high releases of radiation. It could certainly cause problems in the transmission lines, and transportation of materials to and from the plants. It could disperse radioactive wastes stored in drums close to the facility. It could disperse water from the holding ponds and increase radioactivity offsite.

Not only waste heat, but releases of krypton-85 could cause atmospheric changes. This is discussed in the enclosed article from Science, July 16, 1976. As with the aerosols, we don't understand the long term implications of releases of krypton 85, a radioactive chemically inert gas.(11)

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You state that the increased revenue in local taxes due to having the Black Fox Stations would be beneficial. This is an erroneous statement. The taxes must be paid out of revenue charged the customers for electricity, so the increased taxes would be coming from the people of the area.

It is difficult to understand the need of these two 1220 megawatt nuclear reactors (2440 megawatts total) plus the two 500 megawatt coal fired plants (1000 megawatts total) planned for the same county. This is enough electricity for a million and a half extra people- the Tulsa area now contains about 700,000. One fourth of the electricity is contracted by Associated Electric of Missouri. This means that the people of Oklahoma will take the risks of nuclear accidents, releases of radiation, increased temperatures, use of their water, in order for people out of state to enjoy the abundant and probably wasteful use of this energy. Associated is a Rural Electric Cooperative having is eligible for low cost government loans to defray much of the cost of these plants. In effect, the plants will be heavily subsidized by the federal government and the country's taxpayers. Much of the high cost of these plants will probably end up being taken over by Associated Electric since they can get loans at rates of interest about half what the federal government has to pay on its bonds in the marketplace.

Even with massive government subsidies, nuclear power is rapidly becoming prohibitively expensive. Last year, Friends of the Earth estimated that 83 cents of the federal energy dollar went for fission, 3.6 cents for alternative energy sources such as solar and wind, and only a cent and a half for conservation. In a letter sent out by Senator Mark Hatfield, he stated that, even he, as a Senator, found it extremely difficult, if not impossible, to determine just what percentage of the federal budget is subsidizing nuclear power. This subsidy will have to continue for hundreds of years, simply because no utility operating today is going to be too



concerned over what happens to the tons of radioactive wastes they are producing. Their concern is chiefly with returning a profit on services rendered. Health, environmental, sociological and long term effects should be discussed by a comprehensive, hard-hitting and thorough environmental impact statement.

PSO's astronomical prediction of growth in energy demand for the area would have to be based on promotion for new energy intensive industries to the area. These could very well be polluting industries in themselves. With the cost of electricity rising rapidly, customers are going to begin cutting back on wasteful uses of energy, slowing demand. The population growth rate is also leveling off, with an increasing proportion of older people. Many of our older citizens are living on limited incomes, so are certainly not big energy users.

This excess of energy will certainly discourage any attempt at conservation and also effectively lock out for many years, any attempt to use our plentiful and ideal forms of non-polluting energy such as solar and wind. Oklahoma has one of the highest wind velocities in the country, so wind energy would be most practical here. The state abounds with knowledgeable people who have worked in the fields of solar and wind energy and are most enthusiastic about developing this source.

Electricity generated by the Black Fox reactors will be so expensive that the ratepayers will be in the same bind as the serfs in the middle-ages- they will be working longer and longer hours for their feudal utilities. It will be especially hard on the old and the poor and even the lower middle class people. There is no way that the ratepayer can avoid the high costs. If they cut down on energy use because of cost, then the utilities start charging a higher rate to meet expenses. With no incentive for saving energy, consumers are using up our nation's capital in the form of reserves of fossil fuels and uranium.

The figure quoted of 80% capacity for the Black Fox plants is unrealistic. No plant of this size, or any nuclear plant for that matter, has obtained that kind of capacity for any extended period of time. Overall, nuclear power plants are averaging about 56% with capacity dropping rapidly after the seventh year of operation. Hugh plants of 1000 megawatts and over are doing even less well. They are averaging about 45% capacity.

PSO had greatly underestimated the cost of BFS. Mike Mates and Marvin Cook of Citizen's Action For Safe Energy have spent at least three months researching and writing a 70 page report on the cost, need and uranium availability for the operation. While PSO projected a cost of 29.2 mills/ KWhe levelized over thirty years, our best estimate from current costs is 62.5 mills or over twice as m[illegible]. Since the first nuclear reactor was put on line only 19 years ago, and only 11 of the plants operating in 1975 had been commissioned before 1970, we have no assurance that the Black Fox reactors will operate for 30 years. The first plant Shippingport was 60 megawatts, later upped to 90, and most of the plants built before 1970 were small by today's standards, therefore we have had very little experience with the problems that might be encountered with the larger plants.

The safety hazards of these reactors have been underestimated. A nuclear reactor contains enough radiation in its core to equal 1000 Hiroshima bombs, although no nuclear critic charges that a light water reactor will explode like a bomb. The two Black Fox reactors will contain the equivalent of 2 thousand tons of pure radium. (As a yard stick, one ounce of radium at one yard distance will deliver a lethal dose of radiation to the average adult in half an hour.) Just as a plane, no matter how many safety systems, can never be considered without risk because of the



unique danger of flying thousands of feet in the air, so reactors too have peculiar dangers. Elaborate and redundant safety systems are not luxuries, but absolute necessities because of the serious consequences of death, lingering illnesses, genetic damage, and permanent contamination following a severe accident.

The Rasmussen Report ( WASH 1400) estimated that a bad reactor accident (a core meltdown releasing radiation to surrounding areas) could only happen once in a billion years of reactor use, and estimated that 3300 people would be killed outright and 33, 000 suffer latent cancer deaths. An EPA review of the study stated that the possibility of such an occurrence was several hundred times greater and estimated that the accident could cause anywhere from 66,000 to 330,000 latent cancer deaths. A cloud has appeared over the report with the release of a Common Cause Study. They discovered that Dr. Rasmussen was also retained as a consultant on the payroll of five nuclear firms at the same time he was heading the Reactor Safety Study for NRC.

In WASH 1400's main report, the estimate of 1 in 20,000 as the possibility of a core meltdown per reactor per year seems about right. With 100 reactors operating in the near future, that would mean one chance in 200 years of a core melt. It is when the report starts mentioning casualties, long term casualties, health effects, evacuation and decontamination that the whole report starts getting fuzzy. Also with the limited number of civilian reactors operating before 1970, the statistical base can only be guesswork.

The G.E. BWR-6, Mark Three containment is bigger than any plant built to date. The Mark Three is a new supposedly improved design, but solutions can create problems. There are unsolved safety problems in the BWRs such as flow-through vibration. G.E. has scheduled 18 million dollars to work on this problem sometime

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in the future. These tests should be run before BFS is built. Nebraska Public Power is suing G.E. for 125 million largely because of the flow-through vibration problems at their Cooper Station. There are other unresolved problems as well, such as intergranular stress corrosion cracking of stainless steel piping, turbine missile penetrations, anticipated transients without scram (NRC estimates this can happen several times in a reactors life) pool swell, etc.

NRC's bimonthly report, "Nuclear Safety", covering the period from Jan. to June 1976 lists roughly 673 occurances at U.S. reactors during a six month's period- 25 of these requiring shutdown. These issues cover such items (one line) as "Cable Tray Fire Causes Extensive Damage, Brown's Ferry 1 and 2," and " Ice-Condenser Door Freezes at Donald Cook Nuclear Plant". It would never have occured to me that either could happen at a nuclear plant. A member of the public has no way of knowing the seriousness or the triviality of the 673 occurances except by writing and paying Oak Ridge for 673 separate reports. For example, Nuclear Safety lists this item "7/2/75, Earthquake Occurs (cause) Natural Event, (facility) Humboldt Bay." Anyway, with an average of 4 occurances and occasional accidents a day at operating plants, the public has no cause for complacency.

Many communities in Northeastern Okla. have abnormally high levels of radium in their drinking water. Our Dept of Radiological Health has not released the names of the communities where radium levels are high. Consequently radiation released from BFS could certainly add to the radiation levels to which these people are exposed.

No satisfactory means of disposing of the buildings and reactors is suggested. This may not be too much of a problem when the number of reactors is small, but with something like 600 of these projects by the year 2000, we could be decommissioning 20 reactors a year. The Egyptians left their pyramids, but thankfully not radioactive



ones. Our land is pitted and scarred- in many cases ruined- by old mining operations. We certainly don't want the same problems (with the added radioactivity) with abandoned nuclear plants.

There are contradictory reports of the domestic supplies of uranium- but it is doubtful that our domestic supplies could supply the needs of the Black Fox Reactors at least for their proposed 30 year life. It is certain that the price will be over 50 dollars a pound and possibly a hundred for enriched uranium.

You have not considered the effects on human health of the release of asbestos from the plumes. I understand the cooling towers are constructed with a mixture of asbestos.

You have not figured for the extremes of temperatures in the Verdigris River. The water, also, has a high level of particulate matter and would be expensive to purify to the quality needed for a nuclear power plant.

The quality of recreation in the Verdigris River would be lowered. Most people would not be too comfortable eating fish out of a river with a nuclear plant upstream. Likewise, many would be hesitant to go swimming or boating. The aesthetics of the area would certainly be lost with many large transmission lines, construction, traffic, and manufacturing establishments that may locate in the area. In addition to the heating of the water caused by our hot summers, we would add more heat from the plants, creating great increases in algae growth and eutrophication.

In fact, we as a nation are rapidly reaching the limits of growth. We are told we need increasing amounts of electricity, but we also need clean air, fresh water, land for crops, food, open spaces, wilderness areas, woods, and we also need to leave

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some resources for those who come after us. Our current philosophy seems to be pave it over, burn it up, throw it away, and move on to do the same elsewhere. The peo le of Northern Europe have approximately our standard of living- higher health-wise- and using only 40 to 60% as much energy per capita as we do. We must stop and reassess our lifestyle and our wasteful use of energy. We must begin implementing non-polluting sources of energy such as solar wind, human, animal and conservation, conservation, conservation.

I am including a report by my friend, Dr. Charles Hyder of Albuquerque, called "A Quantitative Human Systems Relation; The Hazard Regulator Equation".(12) At first the report seems obscure, but, on closer examination, it makes eminently good sense. After a fifteen year latency period, the problems with nuclear energy seem to be escalating at an exponential rate. I personally have been collecting data on nuclear energy for the last three years, and the amount of clippings, articles, etc has increased to the point where I can hardly keep my files up to date. I have been forced to enlist the aid of friends to keep materials in order and current. Along with the other assaults on the environment and its living creatures, many of us feel that perhaps the expansion of nuclear energy and its Siamese twin, nuclear weapons systems could be last straw for mankind.(13) I would at least hope that his is the last environmental impact statement on proposed nuclear facilities in which you state that the environmental results are minor or negligible.

Ilene Younghein

Ilene Younghein

18 THE OKLAHOMA JOURNAL, THURSDAY, SEPTEMBER 2, 1976

# Nuclear Mishap Revealed

The Washington Post News Service

RICHLAND, Wash. — [illegible]

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Denver Post - Sun - Aug 1, 1976

# Nation's Death Rate Lowest in History

WASHINGTON—(AP)—America's death rate has declined to its lowest point in the nation's 200 years, the government reported Saturday.

Heart disease, strokes and traffic accidents took proportionally fewer lives last year than the year before. These gains outweighed the rising death rates for cancer, murder and suicide.

EVEN THOUGH the nation's population is growing older, the death rate dipped to 8.9 deaths for every 1,000 Americans last year. That is down from 9.1 the year before and the 9.7 in 1968. It is the first time in American history that the death rate has dropped to below 9 per thousand.

The Census report said that 1.91 million Americans died in 1975. That is the lowest number of deaths since 1967, when 1.[illegible] million people died.

Highway and traffic deaths dropped 17.1 per cent from 55,[illegible] in 1973 to [illegible] in 1975, for example. This is probably because of a lower speed limit and requirements for stricter safety standards in cars, according to a spokesman for the National Highway Traffic Safety Administration.

INFORMATION FROM the National Center for Health Statistics shows that the leading cause of death — heart disease — dropped 4.5 per cent from 757,075 deaths in 1973 to 722,570 in 1975. The center reports also that deaths from cerebrovascular disease, or strokes, dropped 8.7 per cent from 214,313 deaths in 1973 to 195,638 in 1975.

Of the 15 leading causes of death, the center reports only three have showed an upward trend in the last two years: the cancer rate increased 4.1 per cent, the suicide rate increased 3 per cent and the murder rate increased 4.1 per cent.

THE CENSUS REPORT shows that the growing proportion of elderly people in the country is linked directly to the falling birth rate. It is no secret that in the last few years, women have been giving birth to an average of less than two children each, bringing the total fertility rate to an all-time low of 1.8 in 1975. Therefore, the proportion of people 65 and older has grown until today they make up 10.5 per cent of the population. That compares with 9.8 per cent in 1970.

At the same time, the total population of the country grew by 1.6 million — or .75 per cent — from 1974 to 1975, the report shows.

The amount of increase was greater than it had been for the three previous years, largely because of the admission of about 130,000 Vietnamese refugees, the report says. "Without the Vietnamese the population gain would have been 1.56 million," the lowest gain in any year between 1936 and 1971.

Life expectancy reached a record 71.9 years during 1975, the latest year for which these figures were available. For men it was 68.2 years, and for women 75.9 years. Life expectancy was 72.7 and [illegible] years for the white and black populations, respectively.

THE SUNDAY OREGONIAN, AUGUST 8, 1976 A5

# Sea N-waste junkyard

Chicago Daily News Service

PARIS — A special train carrying 20 tons of radioactive "junk" from Swiss hospitals and nuclear research centers unloaded July 19 at the small Dutch port of IJmuiden near Haarlem.

As officials with geiger counters stood guard, the cargo was taken aboard the British motorship M.V. Topaz, which sailed into the North Sea and headed for a nuclear dumping ground in the Atlantic approximately 500 miles southwest of Land End, England, and 275 miles from the continental shelf.

When the weather and winds are right, the Topaz will unload its freight of low-level radioactive items encased in concrete-filled steel drums. These will be sunk to a depth of 2.5 miles.

The cargo is part of 6,700 metric tons of low-level waste sunk in the Atlantic since June, and the operation is one of several temporary disposal methods for radioactive materials now in use. Permanent solutions to the waste problem still are being sought in one of the most vexing aspects of the dawning nuclear age.

The Topaz has been hauling radioactive waste out to the Atlantic dumping grounds since 1967. A total of 45,000 metric tons has been sunk inside the 35-mile circle centered at 46 degrees 15 North and 17 degrees 25 West.

Under supervision of the Paris-based nuclear energy agency of the Organization for Economic Cooperation and Development (OECD), Britain, Belgium, Holland and Switzerland supplied this year's radioactive waste, beginning in June.



NOTE:


Reference 2 - R. J. Lifton, "Nuclear Energy and the Wisdom of the Body," Bulletin of the Atomic Scientists, September 1976

Reference 4 - K. Schaub, "Living with Death" condensed from The Survey, Survey Associates, Inc., N.Y., 1932

Reference 5 - J. T. Edsall, "Toxicity of Plutonium and Some Other Actinides," Bulletin of the Atomic Scientists, September 1976

Reference 6 - H. W. Ibser, "The Nuclear Energy Game: Genetic Roulette," The Progressive, January 1976

Reference 11 - W. L. Boeck, "Meteorological Consequences of Atmospheric Krypton-85," Science, 16 July 1976, Vol. 193




The references above are from copyrighted publications and, therefore, not reprinted in this Environmental Statement. They are available for reference in the NRC Public Document Room at 1717 H Street, N.W., Washington, D. C., and at the Tulsa City-County Library, Tulsa, Oklahoma.

San Juan Star
Aug [illegible] 1976

# Quake Toll Forecast At Over 8,000

MANILA, The Philippines (UPI) — President Ferdinand Marcos said Sunday the toll from the earthquake and tidal waves in the southern Philippines would reach 8,000 dead and property losses of $[illegible] million.

But Marcos said the tragedy might have a "silver lining" — an end to the four-year Moslem insurgency in the stricken Mindanao-Sulu area.

Speaking on nationwide television, the Philippine leader said the tidal waves touched off by last Tuesday's quake were so powerful they swept huge concrete pilings inland and buried [illegible] and other [illegible] on top of [illegible] trees.

He said he had ordered a [illegible] nuclear power plant on the [illegible] to [illegible] [illegible] the [illegible].

[illegible] the official [illegible] toll now is 3,000, Marcos [illegible] "there [illegible] 3,000 more missing [illegible] believed dead but this will probably bring the [illegible] closer to 8,000, which is much more than we expected."

He put the number of homeless at about 175,000 and said the government will begin a [illegible] $[illegible] million program to rebuild homes, schools, hospitals, roads and industries wiped out by the catastrophe.

Marcos acknowledged the disaster came on top of four years of intermittent fighting between government troops and Moslem guerrillas in the southern Philippines but said he received reports during his tour of the stricken area the rebel leaders wanted "to return to normalcy."

THE OREGONIAN
AUGUST 7, 1976.

*Fines threatened*

# Trojan told to meet pollution curbs

By WAYNE THOMPSON
of The Oregonian staff

Oregon's director of environmental quality Friday denied Portland General Electric Co.'s request to relax pollution standards at the Trojan nuclear power plant near Ranier.

Environmental Quality Director Loren Kramer also warned that if the Trojan plant, shut down for the summer, is reopened Monday as scheduled, the company could be fined up to $10,000 a day if the waste discharge standards are not met.

In denying PGE's request to relax the standards for chemical and heat discharge, Kramer said, "I am not sympathetic to this problem and I would not wish to relax standards agreed to by PGE when the waste discharge permit was issued for Trojan.

"Our policy will be to enforce the existing permit conditions, limiting these pollutants, and to insure that the plant is operated at whatever production level necessary to achieve compliance," Kramer said.

PGE had asked Kramer and DEQ to grant the utility a one-year relief period from present discharge standards for boron, sodium and heat while the utility studies both the pollutant impa[illegible] on the environment as well as methods of compliance.

Kramer said Friday that violations, both during the previous startup phase at Trojan and in the future, are subject to fines up to $10,000 a day.

"I have no plans currently to fine the company, but if that situation were to change, I would not hesitate to fine them for violations that have occurred previously," Kramer said.

In seeking a one-year relaxation of the discharge standards, PGE admitted violations in boron, sodium and heat discharges into the Columbia River as early as March.

Kramer said PGE's next step would be to make a formal request to the DEQ for modification of its permit (a variance), establishing specific parameters as to temperature, sodium and boron limits.

If such a variance request is received, he said, DEQ would hold public hearings on the request prior to a decision on it by the state Environmental Quality Commission, the public board that governs DEQ.

"However, I have instructed PGE in a letter Thursday that we feel that nothing has been presented by PGE that warrants the relaxation of these limitations, and that such a request would not be supported unless new evidence is forthcoming," Kramer said.

Kramer criticized PGE for its present monitoring and reporting of temperature levels of its discharge into the Columbia, explaining that the procedures do not permit adequate analysis to determine compliance of the standards or the resulting impact on the environment.

He said PGE should correlate and make available such data generated with daily plant flow information and specify if the plant was operating during startup, cool down, normal operation or at what capacity. Most of the previous discharge violations, he said, came during cool down operations.

Kramer also expressed anger at the way DEQ was notified by PGE of a "10-fold increase in steam generator blowdown due to changes in plant chemistry, causing an increase in the heat discharged."

Piping changes made at the Trojan plant were also made by the utility, Kramer said. But these changes, he claimed, affected Trojan's thermal discharge and were not reported to DEQ according to the conditions of the permit.

Kramer said he preferred not to use fines in order to gain corrective measures. "I think fines should be used to get a company's attention, but in this case I think we have PGE's attention. It's just that they don't seem to understand what their permit means," he said.

POOR ORIGINAL

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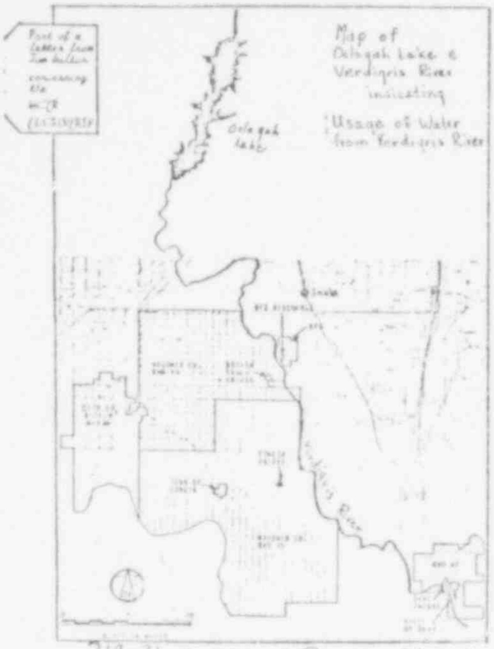
# Proposed City Pact for Nuclear Plant Water Protested

By [illegible]

A contract for the city of Tulsa to supply water for Public Service Co.'s Black Fox nuclear plant near Inola drew protests Wednesday at a Utility Board meeting. [illegible]

Part of a letter from Jim Dalton concerning the WATER [illegible]




## Who Wants to Drink Radioactive Water?

The Verdigris River supplies water for drinking and domestic use by Inola Area, [illegible] as well as to 3 Rural Water Districts, and several irrigation systems. The intakes for all of these are below the discharge point from the proposed BFS.

The discharge from the proposed Black Fox Nuclear Plant will contain radioactive effluents. [illegible]

*While there is a crying need for water in many areas of the nation—PSO is requesting that Tulsa sell almost one-half of its Oologah Lake water rights for use in the proposed nuclear power plant at Inola!*

This has implications for Tulsans (who may in the future be in need of that water). Even if the quality may not be the best, it may be cheaper to treat it than to do without. In the event the water is needed for human consumption—and a drouth should occur—it would be necessary to use it for cooling water for the nuclear plant to prevent a melt-down—and the citizens would do without drinking water!

*Consider these facts taken from the DRAFT ENVIRONMENTAL STATEMENT of the proposed Black Fox Station:*

1. *PSO plans to take up to 28,000 gallons of water per minute from the Verdigris River,*
2. *Approximately 25,000 gallons of water per minute will be evaporated into the air from the air cooling towers if the nuclear plant is built,*
3. *Approximately 3,000 gallons of water per minute will be returned to the river, if the plant is built.*

The above statements have implications for those whose water supply is taken from downstream of PSO's Discharge Area. Oklahoma has been having some strange weather patterns for the past few years. Consider what will happen in Northeastern Oklahoma if 25,000 gallons of hot water vapor is poured into the air per minute! This could create hot, muggy, hazy summer days, and foggy, cold winter days, causing icy roads. Radioactive elements will be emitted with this vapor (if the plant is built) which will be dispersed on the land, plants, and in waterways (Claremore Lake? and other waterways) upwind from the proposed plant site.

Even tho' PSO states that only very small amounts of radioactive elements will be discharged into the river, these will be concentrated in the tissues of those who use the Verdigris River water. Who wants to drink RADIOACTIVE WATER?

Numerous accounts of accidental radioactive water spills from nuclear plants abound in the literature. Around July 18, 1976, the Vermont Yankee Nuclear Plant accidentally released 83,000 gallons of radioactive water into the Conn. River (due to a faulty valve). They were not only excused from this grave error, but were given permission to raise the temperature of the river water excessively (as an experiment to see what effect it will have on the ecology of the river)!

IT IS SUGGESTED THAT THOSE WHO FEEL THEY NEED TO BE HEARD ON THIS SUBJECT, CONTACT THE TULSA UTILITY BOARD AND COMMUNICATE THEIR IDEAS TO THEM. The Board will [illegible]

POOR ORIGINAL

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# The case against nuclear power

--- A Call to Action

Update on the Oklahoma Anti-Nuclear Front: *Water *NRC Hearings *Campaign [illegible]

Many of us Oklahomans have been considering the controversy over nuclear power in the abstract, and that it is such a long way into the future, that it does not concern us! This can no longer be true. [illegible]

Public Service Company of Oklahoma plans to build two General Electric Nuclear Power Reactors on the Verdigris River about 3 miles SW of Inola, Oklahoma—3 miles east of Tulsa and 12 miles south of Claremore. PSO is requesting 50,000 acre-feet of water per year from Lake Oologah to cool the Inola plants—the proposed BLACK FOX STATION, nearly 28,000 gallons per minute!

[illegible]

Proposed Black Fox 1 & 2:

## Energy Path Foes Cited

[illegible]

CITIZENS' ACTION FOR SAFE ENERGY
P.O. Box [illegible], Claremore, OK [illegible]
August, 1976

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You have before you a proposal to sell water to Public Service Company (PSO). I urge you to reject it simply because it is a "bad deal" for the City of Tulsa. The issue is value and there are several methods by which the value may be ascertained I have previously suggested two.

The water is an integral and essential component in the production of $4.1 billion dollars worth of electricity. (This is the value ascribed by PSO to Black Fox 1 and 2 power). The price received by Tulsa, under these circumstances, is far too low.

Another method is to determine the cost to PSO of the next best source. We know that PSO could go elsewhere -- but at a cost. We should be attempting to achieve the best price and it is clear that the price being proposed is not the best price.

The water should be priced at the incremental cost. Older supplies are less costly than new supplies. Replacement water is obtained at a high marginal cost. By selling the water to PSO at less than replacement, or below incremental cost, you are subsidizing PSO and losing revenue for the City of Tulsa. The loss will be borne in other sectors and undoubtedly by the general rate payer.

There are many analogies. Ample literature exists which examines the cost of new development. Often it costs more to add a subdivision to the City than is returned in taxes. Consequently an effort is made to have the new subdivisions pay these extra costs. PSO should, at a minimum, be required to pay a price equal to the cost per unit of replacement water.

The water may be valued by recognizing that the allocation of the resource to PSO forecloses other uses. How many new residences will we not be able to have -- how many industries -- or other commercial enterprises ?

Another method is to consider the price had Tulsa provided the reservoir rather than the Federal government. It is clearly wrong for Tulsa to transfer the public value to PSO. The availabilit of the water in Oologah is obviously as a result of public subsidy. It is economically wrong -- and in derogation of your duties as public trustees -- to simply transfer this subsidy and at the same time fail to realize the full market value for the water.

Examine this proposal as if you were examining a sale that had been made ten years ago. Would you be content today with a long-term, fixed price contract which was based upon prices prevailing ten years ago ? PSO made this very mistake in its agreements with GRDA.

You cannot obtain a long-term private loan at a fixed rate of interest. No private business would enter into a contract such as this. Even PSO makes monthly adjustments to its charges based upon the price of fuel and the price has always risen. PSO's fuel is no different than our water. Normal rates are a reflection of higher costs. As a gas ... in the private sector would you be willing to contract for your oil or gas under the same terms as this contract ?

With respect to the water quality, I make two observations. First, it has now been conceded that we are dealing with quality water and that many communities would be thankful for it. Second, oil tastes bad. But there is a substantial market value for it.

In part the proposal calls for the supply of water as effluent. Bear in mind, however, that it is to be supplied whether the effluent is there or not.

More importantly, though, we see that the price has absolutely no relationship to the cost of producing the effluent, nor is the price even remotely related to the value of the effluent for alternative uses -- including recycling for human consumption. Statements to the effect that effluent has not been sold in the past are irrelevant. We have no experience with the sale of effluent treated to 1983 standards coupled with the factor of short supply of water.

Again, we will be transferring to PSO the public subsidy. It is compounded by the fact additional subsidies are in effect from EPA and from ad valorem and services provided to the utility department by the City.

PSO is asking us to create and maintain a level of waste. This alone should shock your conscience.

But if the water were correctly priced, conservation measures instituted, etc. there would be a reduction in demand. Responses would also take the form of improved efficiencies in use. All of these things need to be understood if for no other reason than they will affect the ability of the City to deliver the required level of effluent.

No harm could come to PSO or the City from further study of this matter. But great harm will come to the City as a result of a wrong decision now.

[illegible]

ALL DAY

SOLAR WORKSHOP

FREE

—

Richard McKim will conduct another of his famous solar workshops at the Creek Indian Nation Complex just North of OKMULGEE, OK, Saturday, September 17, beginning at 9 a.m.

Included will be a tour of solar homes!

CASE has engaged the help of Attorney Tom Dalton to intervene in the Nuclear Regulatory hearings concerning the request for a construction permit for the proposed Black Fox Nuclear Power Plant at Inola, Oklahoma. Mr. Dalton's fees are $30.00 per hour. About $5,000.00 has been raised to date, but the expenses have just about depleted the account. There have been numerous pre-hearing meetings and conferences, and much research in preparation for the hearings.

Because of the many problems inherent with nuclear power, CASE believes this is not the route to take to produce energy in Oklahoma. Both safe alternatives and energy conservation are more desirable!

Because we know you will wish to have played a part in protecting this and future generations of Oklahomans against the radioactive problems resulting from nuclear power, we are asking you to give as much as you possibly can afford to help us in THE CASE AGAINST NUCLEAR POWER!

Because CASE is a lobbying organization and cannot accept tax-exempt contributions, it was necessary to find a Foundation to act as banker for us. The Sierra Club Foundation in California agreed to take care of this problem for us without charge. The checks should be made out to "The Sierra Club Foundation--Tulsa Group." In the left-hand corner, write: "for NRC hearings." Mail the check to CASE, P.O. Box 924, Claremore, OK 74017. We make up then a statement of contributors, their addresses and amounts of checks--and send this along with the checks to the Sierra Club Foundation in California. We also send them the statements, which they pay from this account.

The following is a sample of a correctly written check:

John Q. Public
124 Elm Street
Crossroads, OK 12459

Check # 11505

Date 19 78

Pay to the order of Sierra Club Foundation-Tulsa Group $ 10.00
Ten & 0/100 DOLLARS

BANK OF THE REPUBLIC
P.O. Box xxx
Crossroads, OK 12459

Memo for NRC Hearings

John Q. Public

FOR SALE: (Send check or money order to: CASE, P. O. Box 924, Claremore, OK 74017)

Solar Button--50¢
Solar T-Shirts--$3.00

Solar Pendant --Copper Enamel-- $4.50 — Beautiful Hand-Painted Colors

Solar Fan Cube — $15.00

Solar Aprons

Solar Aprons — $10.00 — Beautifully Hand-Textile Painted with Solar Designs-- Pink, Gold, Blue, Yellow, Green

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P.O. Box 924
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# The case against nuclear power





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# A Quantitative Human Systems Relation,

## The Hazard Regulator Equation

Charles Hyder
Katherine Montague
Peter Montague

It is clear to many observers that the global ecosystem (or biosphere), which supports life, has a finite capacity to sustain injuries without manifesting significant damage.[1] Immediate damage is not difficult to deal with because the negative feedback loops are prompt. But damage associated with long latency periods may build up to levels which exceed the ecosystem's capacity to endure, and may reach those overwhelmingly destructive levels before the magnitude of the damage is apparent to anyone.

Latent hazards are those in which a delay-period intervenes between the time when some hazard-producing activity begins and the time when the consequent damage becomes manifest. For example, carcinogens are latent hazards because typically 15 to 40 years intervene between the time when a human is exposed at effective levels to a carcinogen and the time when a lethal cancer develops in that human.

There are two kinds of latent hazards of which we must be aware. Just as there are genetically-fixed limits for stressing the human body without malfunction, so the ecosystem (the human habitat) is restricted and limited in its capacity to sustain injuries without significant damage. There is now abundant evidence, reported from every scientific discipline, that we are everywhere observing



manifestations of latent hazards both in the ecosystem and in human populations.[2]

Latent hazards, which manifest themselves as damage to subsystems of the ecosystem, are created by activities inextricably associated with the human production system as influenced by the human economic system. Barry Commoner (1976) has described relationships between

> "...[T]he three basic systems - the ecosystem, the production system, and the economic system - that, together with the social or political order, govern all activity.
>
> "The ecosystem -- the great natural, interwoven, ecological cycles that comprise the planet's skin, and the minerals that lie beneath it -- provides all the resources that support human life and activity.
>
> "The production system -- the man-made network of agricultural and industrial processes -- converts these resources into goods and services, the real wealth that sustains society: food, manufactured goods, transportation, and communications.
>
> "The economic system -- the recipient of the real wealth created by the production system -- transforms that wealth into earnings, profit, credit, savings, investment, taxes; and governs how that wealth is distributed, and what is done with it."

Commoner goes on to say,

> "Given these dependencies -- the economic system on the wealth yielded by the production system and the production system on the resources provided by the ecosystem -- logically the economic system ought to conform to the requirements of the production system, and the production system to the requirements of the ecosystem. The governing influence should flow from the ecosystem through the production system to the economic system.
>
> "This is the rational ideal. In actual fact the relations among the three systems are the other way around...."[3]

Numerous observers within the past decade and a half, have concluded that ecosystem-damage parameters have not been given their due weight in human decisions affecting the human production and economic systems. Many people have become convinced that ecosystem damage cannot be allowed to continue at presently accelerating rates. There is, so far, however, significant lack of agreement on how to remedy the situation.

Since latent hazards are produced by the production system, we should assume that growth in the rate of introduction of latent hazards is at least keeping pace with, and perhaps exceeding, the growth-rate of the production system itself.

As Table 1 makes clear, some sectors of the human production system already dwarf natural processes in rate of mobilization of elements (magnitude of annual human mining activities compared to magnitude of material fluxes caused by natural processes, such as wind, rain, and soil erosion, and measured as flow of materials from surface waters into the oceans each year).

As seen in Figures 1 and 2, the human population and the human production system are both growing at rapidly accelerating rates. Overall, the production system is estimated to be growing at a super-exponential rate (now on the order of 5% to 6% annually, integrated over the earth).[4] The global doubling time (τ) for all latent-hazard-production activities by humans is therefore about 12 to 15 years.

There seems to be relatively widespread agreement that humans must regulate their production systems and their economic systems so as to accomodate the needs and limits of the ecosystem. For example, the Study of Critical Environmental Problems concluded in 1970,

> It seems obvious that before the end of the century we must accomplish basic changes in our relations with ourselves and with nature. If this is to be done we must begin now. A change system with a time lag of ten

The size of human mining activities compared to the size of global erosion. Generally speaking, elements with the highest A/B ratios are greatest potential polluters of water.

| Chemical symbol | Name of element | A Amount mined (kg per year) | B Amount added to oceans by rivers (kg per year) * | Ratio of A to B |
|---|---|---|---|---|
| Ag | silver | $6.5 \times 10^8$ | [illegible] $\times 10^6$ | 1.4 / 1 |
| Al | aluminum | $1.1 \times 10^{10}$ | $8.9 \times 10^9$ | 1.2 / 1 |
| Ca | calcium | $5 \times 10^{11}$ ? | $5.7 \times 10^{11}$ | 1 / 1 ? |
| Cr | chromium | $2 \times 10^9$ | $6.7 \times 10^6$ | 300 / 1 |
| Cu | copper | $4 \times 10^9$ | $3.7 \times 10^8$ | 11 / 1 |
| Fe | iron | $2.1 \times 10^{11}$ | $2.5 \times 10^{10}$ | 8 / 1 |
| Hg | mercury | $1 \times 10^7$ | $3 \times 10^6$ | 3 / 1 |
| Mn | manganese | $6 \times 10^9$ | $4.4 \times 10^8$ | 14 / 1 |
| Mo | molybdenum | $3 \times 10^7$ | $1.3 \times 10^7$ | 2.3 / 1 |
| Ni | nickel | $3 \times 10^{[illegible]}$ | $3 \times 10^8$ | 1 / 1 |
| P | phosphorus | $1.4 \times 10^{[illegible]}$ | $1.8 \times 10^8$ | 8 / 1 |
| Pb | lead | $2.2 \times 10^9$ | $1.8 \times 10^8$ | 12 / 1 |
| Rb | rubidium | $9 \times 10^7$ ? | $5.5 \times 10^7$ | 1.5 / 1 ? |
| Sb | antimony | $4.5 \times 10^7$ | $1.3 \times 10^6$ | 35 / 1 |
| Sn | tin | $1.7 \times 10^8$ | $1.5 \times 10^6$ | 110 / 1 |
| Ti | Titanium | $1 \times 10^9$ | $3.2 \times 10^8$ | 3 / 1 |
| Zn | zinc | $3 \times 10^9$ | $3.7 \times 10^8$ | 8 / 1 |

Table 1 adapted from: H.J.M. Bowen, Trace Elements in Biochemistry (New York and London: Academic Press, 1966), pps. 163-164.

POOR ORIGINAL

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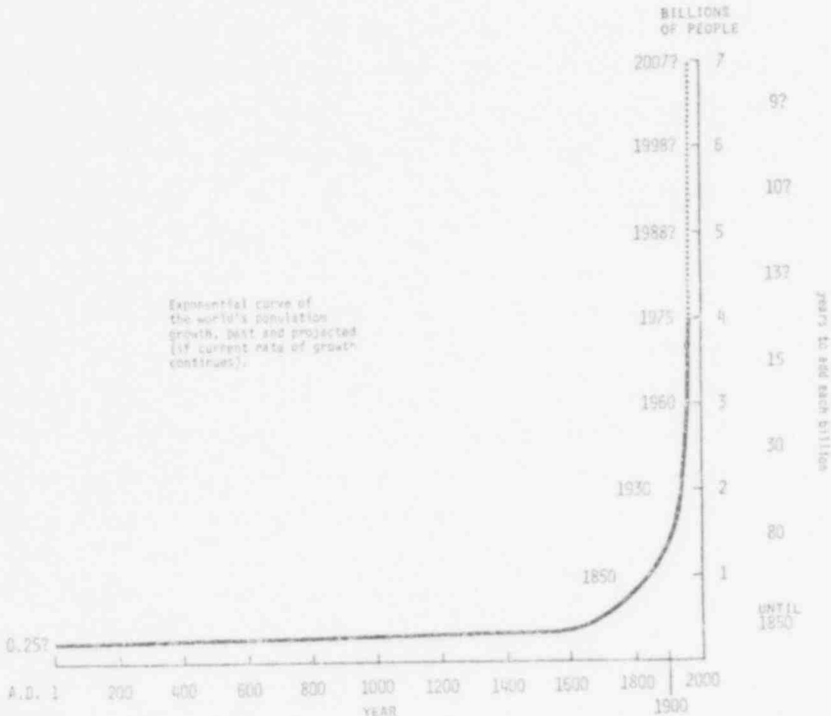


Figure 1 adapted from: G. Tyler Miller, Jr., Living in the Environment: Concepts, Problems and Alternatives (Belmont, CA: Wadsworth, 1975), pg. 8.

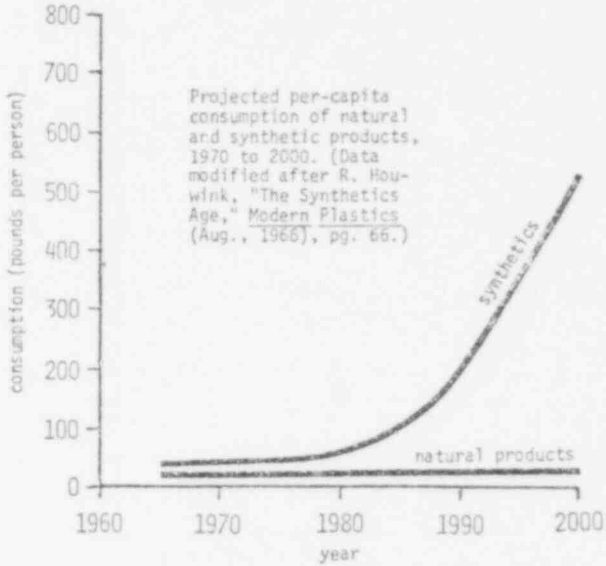


Figure 2 adapted from: G. Tyler Miller, Jr., Living in the Environment: Concepts, Problems and Alternatives (Belmont, CA: Wadsworth, 1975), pg. 17.

719 318



> years can be disastrously ineffectual in a growth system that doubles in less than fifteen years.[5]

This general viewpoint is not seriously disputed by informed people. For example, an unsigned article appearing in a magazine published by Chase Manhattan Bank (New York) and reprinted in the journal, New Mexico Business, concludes that,

> The ecological balance is being dangerously disturbed in a manner which, if continued, threatens man's very survival.... The ecologists appear to have a valid case in terms of the long-term threat to the environment if postwar trends toward increasing pollution were to continue.[6]

We thus find ourselves facing a fundamental dilemma. Informed people now recognize that we need urgently to control our rates of introduction of latent hazards into the ecosystem; yet until now we have lacked the means to rationally and quantitatively determine what levels of latent-hazard control are necessary. An unnecessarily strict latent-hazard control program would be excessively costly (possibly prohibitively costly) to society, and would not be desirable.

On the other hand, a lax latent-hazard control program could spell extinction for the human species, or could mean the collapse of the e system on a time-scale as short as 20 to 120 years.

At this point, we need to clarify our time-horizon for planning efforts. We ask ourselves, on what time-scale should we be concerned about our rate of production of latent hazards? We answer this question with another question: do our grandchildren, whose company we enjoy so much, have the right to have and enjoy grandchildren themselves? On what time-scale do we have a right to "use up" the ecosystem and end all semblance of life as we know it today? For example, on what time-scale do we have the right to knowingly plan to give lethal cancers to increasing numbers of humans, trees, and other long-lived species such as turtles and elephants?

We conclude that we face two important problems. (1) Up to now our planning procedures have failed to take ecosystem-damage parameters into account in relation to the human production and economic systems. (2) In addition, we have failed to find rational means for achieving agreement on the quantitative controls we need to exercise over the production of latent hazards, if we are to prevent the human species from overwhelming itself unwittingly.

We have developed a simple equation which can be used to solve both of these problems. It offers us an exceptionally powerful insight into human systems; thus it lies at the heart of our presentation.

The Hazard Regulator Equation: $\delta \geq 1 - 2^{-\lambda/\tau}$ .

The Equation, called The Hazard Regulator Equation (THRE), establishes rational levels of control which need to be implemented to regulate activities which cause the production of latent hazards. We derived The Equation so that we could address quantitatively the impacts of latent hazards on humans (a subsystem of the ecosystem). As we developed THRE, we realized the relation with human production systems and human economic systems. There are three var... s in The Equation: $\delta$, $\lambda$, and $\tau$. They have the following meanings:

$\lambda$ is the latency period between the time when a hazard-producing activity ($\ell$) begins and the time when damage from that activity becomes evident.

$\tau$ is the doubling time for increasing the magnitude of the hazard-producing activity.

$\delta$ is the fractional cutback required of a hazard-producing activity.



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In Figure 3, $\ell$ signifies the level of production of latent hazards (by any activity) at that time (Point A) when it is determined that latent damage has become manifest at unacceptable levels.

Derivation of THRE: $\delta \geq 1 - 2^{-\lambda/\tau}$

For an average doubling time of $\tau$ for the hazard production rate ($\ell$) of a hazardous substance with an average hazard latency period of $\lambda$, a cutback ($\delta$) must inevitably occur when the latent hazards become evident at a publicly unacceptable level. The production rate that we care about is that earlier production rate ($\ell_o$) responsible for the current unacceptable levels of latent hazards.

The definition of "the fractional cutback" ($\delta$) is

$$\delta \equiv \frac{\ell - \ell_o}{\ell} \quad (1)$$

Since the doubling time is $\tau$, we can write $\ell$ for time t:

$$\ell = (2^{t/\tau})\ell_o \quad (2)$$

If we substitute $\ell$ from Equation (2) into Equation (1), we get:

$$\delta \geq \frac{2^{t/\tau} - 1}{2^{t/\tau}} , \quad (3)$$

or

$$\delta \geq 1 - 2^{-t/\tau} \quad (4)$$

Since the time-difference between the occurrence of discharge rates $\ell$ and $\ell_o$ is $\lambda$, $t = \lambda$; and we get

$$\delta \geq 1 - 2^{-\lambda/\tau} \quad (5) \qquad \text{Q.E.D.}$$

Thus we find that $\lambda$ and $\tau$ are equally significant in determining $\delta$.

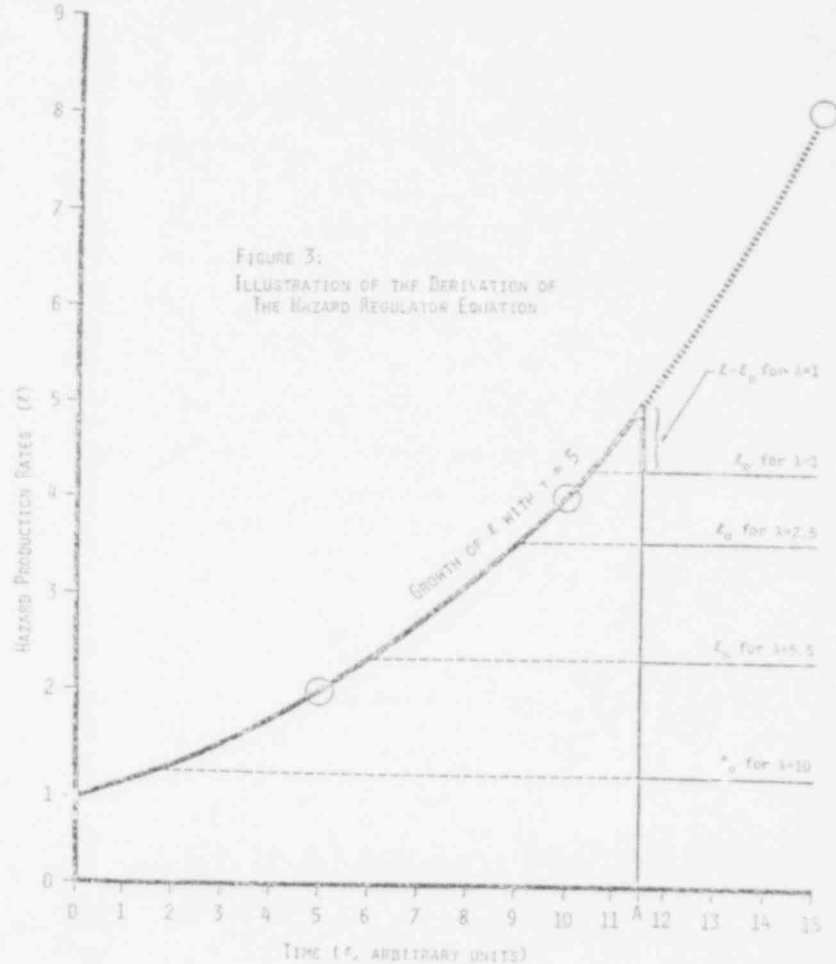


Figure 3: Illustration of the Derivation of The Hazard Regulator Equation

## Discussion

The Hazard Regulator Equation is a powerful explanatory tool revealing relationships among three variables characterizing human activities (δ, and τ) and the human environment (λ). In its three different forms (solving for δ, τ, or λ), then, The Hazard Regulator Equation can be used to address problems from three fundamentally different perspectives. All three perspectives seem to open up fruitful new avenues to explore.

Planning Strategy No. 1 (Curative Planning) You are are time A in Figure 3; a latent hazard has become manifest as damage at unacceptable levels; you know what τ has characterized the production system and λ is now evident; you solve The Equation for δ. Then you know how much cutback you've got to apply to the latent-hazard-producing activity.

Planning Strategy No. 2 (Preventive Planning): You are at time 0 in Figure 3; you haven't created any latent hazard yet, but you're planning to do so. You get a value for λ; you know what δ-values you can live with economically when you reach time A, and you solve for τ. You now know how fast you could afford to expand the activity you're planning.

Planning Strategy No. 3 (Commercial Planning): You know what δ you can live with - your investors (board of directors, economists) tell you that; you know what τ you've got to maintain to show a minimum profit and you solve The Equation for λ. Now it's easy to find what λ-values are profitable to become or stay involved with. Any activities with characteristic λ-values smaller than the λ-value you derived from The Equation are systematically a sound investment. Activities with larger λ-values than you've derived will prove systematically to be a poor investment.

The λ term characterizes the earth's ecosystems, upon which human production systems are dependent. Effects in complex systems, such as living systems, will be delayed many times before manifesting themselves. The λ term of The Hazard Regulator Equation can help us avoid self-destruction through unwitting creation of an overwhelming number of latent hazards. The Hazard Regulator Equation can be used to define "unwitting" precisely.

The τ value of The Equation encompasses hazard production rates. The rate at which hazard production rates grow (τ) directly affects the economic system (the cutback (δ) needed when latent damage becomes manifest), and the ecosystem which manifests the latent damages (λ).

The δ value of the equation encompasses the economic system. If δ becomes too large, our economic entities collapse. For $\delta > 0.15$ we experience a definite threat to any competitive economic organization.

Thus we can see that The Hazard Regulator Equation inescapably relates three very important variables that characterize Commoner's paradigm. Through THRE we find that the human economic system (δ) conforms to the equal constraints of the antagonistic characteristics of the human production system (τ) and the world ecosystem (λ).

## Applications

Applications of The Hazard Regulator Equation ($\delta \geq 1 - 2^{-\lambda/\tau}$):

1. Pollution producing industries with latent hazards:
   - (a) Fossil fuels → $CO_2$ → terrestrial greenhouse → icecap melting ($\lambda_m$) → elevation of sealevel by 50-100 ft.
   - (b) Nuclear → radioactivity ($\lambda_r$) & cancer ($\lambda_c$);
   - (c) Surface discharges (nuclear & chemical) → vadose zone ($\lambda_v$) → groundwater (some $\lambda_c$);
   - (d) Aerosols ($CF_2Cl_2$ or $CF_3Cl$ or $CFCl_3$) and SST's ($NO_x$) → $O_3$ reduction ($\lambda_o$) → U.V. enhancement → skin cancers ($\lambda_c$); and
   - (e) Mobilization of toxicants into atmosphere and hydrosphere ($\lambda_f$) → killer smogs; offshore drilling → crab population decimation; nitrogen and phosphorus discharges into lakes → excessive eutrophication.

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2. Uncontrolled growth of cultural systems:
   (a) Uncontrolled reproduction ($\lambda_p \gtrsim 20$ yrs.) → overpopulation → inadequate food supply, famine, etc.; and
   (b) Uncontrolled profits → unsound economic practices ($\lambda_e$) → economic disaster → war, etc.
   (c) (a) and (b) occasionally lead to revolution, producing cutbacks ($\lambda_v$).
3. Manipulation of information by vested interests:
   (a) Coverups ($\lambda_d$) inappropriate understanding → chaos → inappropriate behavior → eventual withdrawal; and
   (b) Unrealistic or false promises ($\lambda_\ell$) → fruitless commitments → wasted time, effort and assets → loss or termination.
   (c) (a) and (b) produce the latent hazard of revolution ($\lambda_v$) as in 2(c).
4. Maintainance of coveted place[illegible] practices, etc.: ($\lambda_\omega = \infty$) $\tau = \infty$ ;
   (a) Biosphere, atmosphere and hydrosphere wilderness areas ($\tau$ [illegible] $\infty$).
5. Production of non-degradable substances must stop: $\lambda = \infty \rightarrow \tau = \infty$ .
6. Individual health problems with latent mortalities:
   (a) Overeating → obesity ($\lambda_h$) → heart attacks ($\delta_h$), and
   (b) smoking → emphysema ($\lambda_y$) and lung cancer ($\lambda_c$).

We now give an extended example from the six topics mentioned above.

1(a) & (b) <u>THRE and U.S. Energy Problems</u>.

Since U.S. industry can usually endure fractional cutbacks of 20% or less without serious threats to survival, we have limited the range that $\delta$ can occupy in THRE, for this example.

$$\delta \geqq 1 - 2^{-\lambda/\tau}$$

is thereby solved for $\tau$ if we can learn anything about the range of latency periods



associated with the major (current and near future) energy technologies. At present, fossil fuels dominate our energy technologies. The fossil fluids are in short supply, so there is a federal-industrial commitment to nuclear power.

We examine these technologies in the context of THRE.

1 (a) <u>$CO_2$ Greenhouse Heating and Polar Icecap Melting</u>.

$CO_2$ and $H_2O$ are the inescapable products of fossil fuel combustion. $CO_2$, and to a lesser extent $H_2O$, produce a dramatic greenhouse effect when the $CO_2$ abundance is high enough. This greenhouse heating elevates the temperature of the earth, and polar icecap melting and worldwide weather modification are two of the consequences.

Since the delay time ($\lambda$) between the onset of significant <u>$CO_2$ greenhouse heating of the atmosphere</u> and the onset of detectable shrinking of the polar caps is very short, probably weeks-to-months, we can calculate the atmospheric $CO_2$ doubling time as a function of the range of cutbacks ($\delta$) that the fossil fuel burners are willing to endure ($\delta \leq 0.2$) via THRE:

$$0.2 \geqq 1 - 2^{-(1/10)/\tau}$$

$$\tau \geqq 0.5 \text{ years.}$$

Thus, <u>we are not led to a fossil fuel steady state</u>.

Today the observed [illegible]ues for the atmospheric $CO_2$ doubling times are $300 \leq \tau \leq 600$ years. So $\tau$ (observed) >>$\tau$ (THRE) which is what we want to see.

1(b) <u>The Nuclear Industry, Radioactivity and Cancers</u>

Today the fission nuclear industry is characterized by a two-pronged, long latency period problem ($\lambda$ > centuries) while the alternative energy generating technologies (fossil, wind, solar, marine, geothermal, etc.) are characterized by average latency periods that are very short (days $\leq \lambda \leq$ months) compared with industrial doubling times ($\tau \approx 10$ years), i.e., $\lambda/\tau < 1/100$ and $\delta < 0.05$.

Since 1960, the average doubling time for installed nuclear capacity has been $\tau \simeq 2.5$ years. The two-pronged long latency periods arise from two causes: (1) The latent hazard imposed by radioactivity is usually via cancers which all exhibit average latency periods of more than ten years ($\lambda \geq 10$ years), and (2) radioactivity from the fission daughters exhibits many half-lives that range between 2.5 years and 212,000 years ($2.5 \leq \lambda_r \leq 2 \times 10^5$ years). There are enough of each of these long-lived isotopes produced in nuclear reactors annually to exterminate the human population of the earth many times over. Annual releases of $10^{-7}$ of these radioactive wastes would still kill many people, but those deaths would not show up as "statistically-significant" in the world's annual figures for cancer deaths.

What this means is that we can look forward to having to endure cutbacks in installed (and operating) nuclear capacity of 99% or more in the near future. When we make the cutback decision depends on when there is one, or a few, releases of significantly more than $10^{-7}$ of the radioactive wastes now in reactors, storage pools, trucks, storage tanks, storage trenches, deep six barrels, etc. Since we typically achieve 0.1%-to-1% release over a long time period, e.g., at U.S. nuclear waste repositories, we can expect to see one of these disastrous releases within the next five-to-ten years. Then we can expect to see virtual 100% cutbacks being demanded by a public newly aware of the nature of the long-lived latent hazards inextricably associated with the industry.

Thus, any informed investor would select a fossil fuel power plant over a nuclear power plant because the latter is certain to be closed down long before the projected life of the plant has been realized.

This example illustrates the basic utility of THRE to technological societies; THRE provides a quantitative basis for differentiating between those technologies that must be strictly regulated ($\lambda >$ decades $\Rightarrow \tau \geq$ centuries) and those with adequately short latency periods ($\lambda < 1$ yr.) to permit "business as usual".

We have provided one quantitative relation that accomodates Van Rensselaer Potter's call for a bioethical basis for decision-making.[7]

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July 10, 1976

Submitted to Nature 7/13/76



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4 Study of Critical Environmental Problems, Man's Impact on the Global Environment (MIT Press, Cambridge, Mass., 1[illegible]), pgs. 114-120.

5 Ibid., pg. 126.

6 Chase Manhattan Bank, New Mexico Business, 25, 7-10, 25-26 (May, 1972).

7 Potter, Van Rensselaer, Bioethics: Bridge to the Future (Prentice-Hall, Englewood Cliffs, NJ, 1971).


**Doomsday Expectations**

During the past 2 years I have been conducting an informal poll on the doomsday expectations of persons with whom I work. I have asked students and faculty to record, by secret ballot, their response to the following question: "How long do you think our civilization will continue to exist in the developed state before it is vastly diminished or destroyed?" I ask respondents to record their intuitive hunches. Virtually everyone polled was able to record a numerical answer within a minute.

The estimates varied among groups but were surprisingly low overall. Twelve graduate students in a class in environmental planning had a modal expectation of 100 years in 1975, which increased to 150 years (16 students) in 1976. A sample of 35 graduate students in planning as a whole gave civilization a 50-50 chance of lasting 200 years, and 16 architecture graduate students gave it 100 years (1). Faculty members had substantially more optimistic expectations. Eight who responded from the planning faculty gave civilization a 50-50 chance of lasting 700 years, and four members of the architecture faculty gave it 500 years. Perhaps the most provocative result came from an upper undergraduate class in environmental biology for nonmajors that had a modal expectation of 25 years (26 out of 94 students gave answers of from 20 to 30 years).

Regardless of who ultimately may prove to have guessed "best," it is significant that those who teach planning have quite different implicit planning horizons from those of their students and that a sample of undergraduates gave their society a life expectancy not as long as their own. The number of "indefinitely" or "forever" answers was very few (3 out of 122). Changing attitudes toward the apocalypse might be an interesting social indicator, although its interpretation in terms of causal factors is undoubtedly not simple.

I invite interested *Science* readers to poll their own associates similarly (2).


WALTER E. WESTMAN

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1. [illegible]
2. [illegible]

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3900 Cashion Pl.
Okla. City, Okla. 73112
Sept. 7, 1976

Director, Division of Site Safety and Environmental Analysis
Nuclear Reactor Regulation
Nuclear Regulatory Com.
Washington, D.C. 20555

STN 50- 556/557

Dear Sir,

Please include the enclosed report on radiation and life shortening with my previous comments on the Draft Environmental Statement for the Black Fox Reactors 1 and 2. STN 50-556, 50-557. In your draft statement you have not properly evaluated the effects of radiation on aging.



Sincerely,
Ilene H. Younghein

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HEALTH EFFECTS OF LOW LEVEL RADIATION

Rosalie Bertell, Ph.D.
Roswell Park Memorial Institute

Text of presentation to be made at the national meeting of American Public Health Association, Session: Radiological Health and Safety in the Production of Energy Presiding: Stephen Shafer, M.D. 2:00 p.m., Tuesday, November 18, 1975
Sponsor: Radiological Health Section

This investigation was supported by Grant Number CA-11531, awarded by the National Cancer Institute, DHEW.

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My focus this afternoon is on the question of health effects for adults exposed to ionizing radiation. My contribution to the understanding of these complicated phenomena is primarily a rigorous demonstration of the existence of an aging effect of such exposure in humans, together with a quantification of this aging effect. Although the aging hypothesis has been with us for a long time, this is the first statistical test of its validity on humans in clearly demonstrable terms. Quantification of the effect is given in terms of the aging in years expected per rad of exposure per person. Although the analysis was done on exposure to diagnostic x-ray and leukemia, the methodology can easily be applied to other diseases or signs of aging and other radiation sources. What is important is that effects can be measured, and prohibitively large sample sizes are not required.

The measurements which I have obtained relative to exposure to diagnostic x-ray are startling enough to call for much more investigation before further national commitment to nuclear generation of electricity. I leave you to envisage for yourself the results of a generalized acceleration of the aging process in the population with increasing levels of radiation pollution. We are dealing with an effect probably as inevitable for each one of us as death and taxes. We are no longer dealing with a hazard which might cause illness to some persons, but leave the majority untouched!

What I am reporting today is the result of on-going research. You will no doubt be full of questions--even as I am. Given the time, assistance and money, I can answer many of the questions, but for now, I will have to be satisfied with bringing you up to the degree of clarity



which I have reached to date. I will try to sketch the main thread of discovery--leaving to the discussion period the complicating factors with which we have had to deal. I am omitting a review of the literature because of limited time, and the importance of communicating to you the results. I would be glad to supply anyone with a bibliography of pertinent material by mail after the meeting, if this is requested in writing.

The first major breakthrough in methodology was development of a method for assessing the per plate relative risk of non-lymphatic leukemia for diagnostic x-ray. The term non-lymphatic means that I am excluding from this study the acute lymphatic leukemia, which occurs primarily in the children, and the chronic lymphatic leukemia, which has an age distribution significantly different from all other forms of leukemia. In this study, age refers to the chronological age of the subject at diagnosis of leukemia. The non-lymphatic leukemias are the acute and chronic myelocytic and monocytic forms, the stem cell and other unspecified forms not diagnosed as lymphatic.

This estimate was made through careful analysis of the Tri-State Leukemia Survey data, using specifically the male cases and controls 45 years of age and older. This group of cases had previously been shown to be radiation related. The Tri-State Leukemia Survey was administered in selected areas of New York State, Maryland and Minnesota, between 1959 and 1962. All reported cases of leukemia and a random sample of controls were interviewed. This is a well known survey, and ample information on it can be found in the literature. The population base for the study was about 13 million, and the random sample controls were chosen at a rate of approximately 1 per 3 thousand.

The adult sample of the survey, those 15 years and older, includes 1,400 leukemic cases and 1,370 random controls. Detailed information on disease history, mobility, exposures to suspected hazards, and personal history was gathered. Verification techniques included contacting all medical personnel, hospitals and laboratories mentioned. Detailed information on the site and number of diagnostic x-ray plates taken was obtainable for about half of the sample, and only such verified reports were used in this study. Verification techniques could not be shown to have introduced any bias into the study.

Slide 1 summarizes this work and shows the fit of the theoretical model, which assumes 5% increase in relative risk of non-lymphatic leukemia with each verified trunk x-ray plate. In this study, all x-ray received 6 months or more prior to diagnosis for cases and prior to interview for controls, was considered. Verified x-ray reports spanned a twenty year period of time.

In subsequent studies two important modifications were made to insure clarity of results. First, we further limited the x-ray considered to that received one year or more prior to diagnosis or interview, to assure no possibility of excess reports from the cases because of diagnosis of the leukemia itself. This was an added precaution, as such bias was not discernible in the per plate study. The second change was a shift from the rather vague measure of number of x-ray plates, to the skin dose in rads received. The conversion factors used are shown on Slide 2, and were taken from the 1964 report of HEW. This report was considered most appropriate for the time period of the Tri-State Survey.



It was an easy mathematical step to move from an estimate of the per-plate increase in relative risk of leukemia to an estimate of a per-year increase in relative risk with natural aging. The 1960 census for appropriate areas was used for a base. Slide 3 shows the results of this analysis. You will note that the per-year increase in relative risk is 5 to 6%--very close to the per-xray-plate relative risk previously noted. This was the clue to unraveling the whole puzzle!

There are many contesting hypotheses for explaining the increased relative risk of non-lymphatic leukemia with either age or exposure to ionizing radiation. It is not my purpose to become involved in these hypotheses. I wish rather to test "sameness of effect"--or in plain language, I wish to test whether or not comparable doses of time and/or exposure invariably produce the same relative risk. To test this hypothesis, I introduced a quantity which I call exposure age: Chronological age plus k times the skin dose of x-radiation received in rads. The quantity k represents the amount of "aging" assigned to each rad. This aging was assumed for both the cases and controls, and in the analysis they are matched on the basis of this exposure age. If we assumed k equal to one, that is, exposure to one rad is equivalent to one year natural aging, then a person with exposure age 43 might have chronological age 40 with 3 rads exposure, or chronological age 30 with 13 rads exposure, or any other possible combination.

If my hypothesis of equivalent effect is correct, when cases and controls of the correct exposure age are compared, the incidence rates of non-lymphatic leukemia for those reporting more x-ray exposure should be the same as the incidence rate for those not so exposed. This is manifested statistically as a risk of one for disease in the exposure group relative to the unexposed group. If k is taken to be zero, i.e., no age adjustment is made for exposure, we would expect to have a risk of disease in the exposed group relative to the unexposed group greater than one. This is because the exposed persons are biologically in an older age bracket where disease incidence rate is higher. If k is "too large", the age shift assumed is too great, and we expect the risk of disease in the exposed group relative to the unexposed group to be less than one. This is because the exposed group is biologically younger than the given classification, therefore having a smaller incidence rate of disease.

Slide 4 should make this concept clearer. This slide gives the over-all analysis of the adult sample with verified x-ray reports--824 controls and 450 non-lymphatic leukemia cases. Each line of the table is the summary line from an analysis of the entire sample, with each person's age adjusted according to the k value indicated in the first column. All the relative risks are exposure age adjusted. The column to the far right indicates the probability of such a summary risk occuring by chance when the true relative risk of disease is one. This analysis includes all sites of radiation exposure, and is "heavy" with dental x-ray. The behavior of the relative risk is exactly what was predicted, and a region of acceptable age shift is clearly discernible. I should add here that these tests were carried out with highly sophisticated computer techniques developed at Roswell Park Memorial Institute. Without this software, and the willing [illegible] able assistance from the staff of the Biostatistics Department, this task would have been monumental.



This software is in a ready-to-go state, and has broad flexibility for applications to related questions.

At this point in the analysis we can conclude that the increased relative risk of non-lymphatic leukemia due to exposure to 15 or more rads diagnostic radiation to any site can be totally explained by an age shift for both cases and controls relative to the amount of exposure each reported. The acceptable amount of shift is clearly delineated and rigorously demonstrated. I repeat, this is the first instance of such precision in measurement for an aging effect in man.

You will recall that the first insight into equivalence of years and radiation exposure for increasing relative risk of non-lymphatic leukemia came from analysis of the male population over 45 years of age. A special study of this group was made to test this original observation. Only trunk x-ray was included in this study.

Slide 5 shows the analysis for the relative risk of 5 or more rads skin dose of trunk x-ray. It will be recalled that the present NRC permissible exposure level for workers in the nuclear industry is 5 rad per year. Trunk radiation dose was spread over as much as twenty years in this x-ray study. Again the predictable pattern under the equivalence hypothesis appeared, with a slight upward shift in amount of aging per rad exposure. One would expect slightly "stronger" results with the elimination of dental x-ray exposure, under several theories of biological mechanisms of aging. This analysis of trunk x-ray exposure included 269 male controls and 214 male non-lymphatic leukemia cases.

Similar procedures were followed, using as exposure cut-off, 10 or more rads, and 15 or more rads, with similar results. When these



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higher cut-offs were used it was noted that the "exposed" category included essentially, persons with reports of G.I. series, spinal examinations or other major abdominal procedures. Slide 6 shows these results. There is again a slight upward shift in k values, and an essential consistency of results.

What seems clear then, is that it is possible to account totally for the radiation related increase in relative risk of non-lymphatic leukemia by a simple and well defined age shift. For trunk exposure in males 45 and older this age shift is most probably between .6 year and 1.45 years per rad skin dose. The easily remembered formula: one rad is equivalent to one year natural aging, is consistent with my findings.

In attempting to relate these findings to the hazards posed by the nuclear industry, we could find reasons to support direct translation of results, to posit an increased aging effect and to posit a decreased aging effect. This dispute will be settled only by direct verification--which is possible using these techniques. If workers in the nuclear industry are aging at the rate of 6 years for each year they receive 5 rads exposure, this will soon become a national calamity. The questions of excessive use of diagnostic x-ray, and the combination of medical exposure with excessive environmental pollution must be faced as an important public health problem.

One more important point. This analysis would have been impossible without precise information on each case and control. Such fine analysis cannot be carried out using vital statistics as presently collected and published. If we wish to answer the epidemiological questions of the



1970's, we must update both our statistical methodology and our methods of data collection. Neither government nor industry has taken initiative in these areas.

Present NRC standards of permissible exposure levels are based on extrapolations and not direct human studies. The claims of industry relative to health hazards are simplistic and for the most part negative. It is relatively easy to discredit studies based on inadequate data and methodology. It would be more honest and responsible to set up an adequate national data bank and become familiar with new approaches to statistical evaluation in an attempt to answer the concerns of scientists, and, in fact, of most Americans, before irreparable harm is done.

Much could be said about other radiation related diseases, such as coronary, artheriosclerosis, cataracts, and various solid tumors. These are also common diseases of aging and could be studied in the same way as leukemia. These studies would perhaps clarify some of the mechanisms of aging, as well as the more generalized effects of ionizing radiation. The need for such studies is clear and urgent. The means are at hand. There is no excuse for non-action or lack of cooperation of government and industry with public health research. I have presented a serious, well documented case in support of a real threat of accelerated aging for every person exposed to ionizing radiation. This presentation must be replied to with an equally serious, independent and well documented study on persons exposed to ionizing radiation in the nuclear industry. Elaborate reports of impossibility, false and secretive discrediting of scientists who speak out against this hazard, and other evasive tactics can no longer be tolerated.

Stephen G. Schmelling
222 S. Country Club
Ada, Oklahoma 74820

September 2, 1976

Mr. Jan A. Norris, Project Manager
Environmental Projects Branch 3
Division of Site Safety and Environmental Analysis
United States Nuclear Regulatory Commission
Washington, D.C. 20555

Re: NRC Docket NosSTN50-556
STN50-557

Dear Mr Norris:

Thank you for your letter of August 4, and the copy of the Black Fox Station Draft Environmental Impact Statement. The draft statement for the Black Fox Station discusses a number of expected environmental impacts in great detail, but, in my opinion, it does not give adequate attention to the following points.

Availability of Water

Section 9.2.1 discusses the recommended rate of water consumption by a powet plant relative to the 7 day 10 year low flow of the source of its cooling water. Using criteria based on a State of Indiana power plant siting law and National Academy of Engineering reports, the Black Fox Station would require a 7 day 10 year low flow of 352 cfs. The draft statement does not contain the 7 day 10 year low flow data for the Verdegris River, but does state that it is less than that required by the above criterion and, implies that it is, in fact, considerably less than this criterion.

The draft statement contains no discussion of the environmental impacts which might arise from the fact that the flow in the Verdegris at the proposed Black Fox Station site does not meet this typical water supply recommendation for siting. All environmental impacts such as entrainment of small organisms (Section 5.6.7.1) are discussed in terms of the 30 day average flow. Since the 30 day average low flow could be expected to be substantially higher than the 7 day 10 year flow, the relative maximum withdrawal rate, and consequent destruction of small organisms could be somewhat higher than the figure of 16% given in section 5.6.2.1, at least for a period of several days. The effect of this on the plankton communities may or may not be severe, but it at least ought to be investigated and discussed.

Need for the Plant (Chapter 8)

The discussion of the need to construct the plant on the proposed schedule seems incomplete in at least two respects. First, there is no discussion, implicit or otherwise, of the extent to which the need for the plant could be reduced by using solar energy for space heating





and cooling, and water heating. This is one of the largest potential residential uses of new generating capacity. The climate of Oklahoma with its relatively mild winters and high percentage of sunny days is favorable for this use of solar energy. In fact, there are presently several solar heated houses built or under construction in Oklahoma. Such uses of an alternative energy source might allow construction of the Black Fox Station to be postponed by several years with no loss in service to the utilities customers.

Second, one of the reasons given in Section 8.4 for urging that the plant be built to go on line in 1983, rather than 1985, which is the first year the NRC staff feels it will be needed, is that it will aid in husbanding natural gas supplies. However, none of the estimates of PSO's future generating capacity (eg Table 8.8) show any reduction in gas-fired capacity when the Black Fox Station comes on line in 1983. It is thus not apparent from the published information how putting the Black Fox Station on line two years before it will be needed will conserve natural gas resources. In addition, there is no discussion of the alternative of converting some of PSO's existing gas-fired capacity to coal as a means of husbanding natural gas, if that is indeed one of the reasons for constructing the Black Fox Station on the proposed schedule.

Energy use is currently in a state of transition from high rate of growth to much lower rates of growth. It seems likely that a delay of a few years would allow time for a much clearer picture of the actual need for the Black Fox Station to emerge.

Urban Outmigration

During the years it is in operation, the Black Fox Station will generate large tax revenues (Table 4.6). Indeed, they will be enormous on a per capita basis if the population of Inola is anything like its present size or even twice as large. Such funds could provide very high quality community services, such as schools, at relatively low cost to the town residents. Since the town of Inola is within commuting distance of Tulsa, and the Tulsa metropolitan area is already expanding in an easterly direction, it is also likely that these large tax revenues and low cost services could attract a significant number of people into the Inola area in addition to those directly associated with the operation of the Black Fox Station. Large population increases have occured in similar situations following the construction of a large nuclear power station. The effect of such large population increases is a mixture of benefits and problems, but both are significant enough to deserve discussion in the Black Fox Station environmental impact statement. Such discussion is lacking in this draft statement.

On Site Storage of High Level Wastes

There is at present no U.S. facility for the storage of high level nuclear wastes from nuclear power stations, nor any operating reprocessing facility. Nor is there any firm date as to when this situation will change. Should this situation still be existing seven years from now when the Black Fox Station goes on line, or should there be an extended period when reprocessing facilities were unavailable it would probably be necessary to temporarily store spent fuel elements at the Black Fox Station site, following current practice in such cases. The draft statement contains no discussion of the environmental effects of this practice.

Thank you for your consideration of these comments.

Yours truly,

Stephen G. Schmelling

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DEPARTMENT OF TRANSPORTATION
UNITED STATES COAST GUARD

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RECEIVED
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U.S. NUCLEAR REGULATORY COMMISSION
Mail Section

Mr. W. H. Regan, Jr.
Chief, Environmental Projects Branch 3
Division of Site Safety and
Environmental Analysis
Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Regan:

This is in response to your letter of 15 July 1976 addressed to Mrs. Conner concerning a draft environmental impact statement for Black Fox Nuclear Station, Units 1 and 2, Rogers County, Oklahoma.

The concerned operating administrations and staff of the Department of Transportation have reviewed the material submitted. We have no comments to offer nor do we have any objection to this project.

The opportunity to review this draft statement is appreciated.

Sincerely,

D. J. [illegible]
Captain, U. S. Coast Guard
[illegible]
[illegible]
By [illegible] Commandant

# Sierra Club

Reply to: Chairman, Tulsa Group
Oklahoma Chapter Sierra Club
1959 E 33rd Place
Tulsa, OK. 74105

September 3, 1976

Director, Division of Site Safety &
Environmental Analysis
Office of Nuclear Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

RE: Public Service Company of Okla.
Docket #STN 50-556; STN 50-557

Gentlemen:

The following are comments of the Tulsa Group of the Oklahoma Chapter of the Sierra Club. We request acknowledgment of receipt of these comments. We further request that the comments be made a part of the record of the proceedings in which reference is made above.

A. The treatment given to water supply and water use is inadequate and inaccurate. Applicant has no water supply as of this date and will not, in any event, be guaranteed water.

1. The present proposal with the City of Tulsa provides that the City may cancel at any time upon resolution of the governing body that the water is required for other customers and citizens.

2. Continuous service is not guaranteed and the City has the right to interrupt for causes beyond its control.

3. The City has the right to substitute effluent in some degree. However, the City may not discharge the level of effluent required because the assimilative capacity of the receiving stream is insufficient.

a. The DES fails to assess the impact upon the receiving water, Bird Creek, of the effluent.

b. The DES fails to assess the impact and analyse the costs required to be borne by the citizens of Tulsa (or more properly Applicant) of the added treatment requirements if the City is to substitute effluent.

(overleaf)

9418

c. The DES fails to account for or analyse the consequences and impact of the problem presented by the fact that the City may be precluded, under the law of Oklahoma from selling the effluent once it is discharged into the stream. Under such circumstances the City may choose not to maintain the level of effluent.

4. The DES fails to analyse the impact of the level and quality of effluent upon Red Bud Valley, a preserved nature area along Bird Creek.

5. The DES fails to analyse the impact of the imposition upon the citizens of Tulsa of increasing costs for water.

6. The cost-bebefit analysis is totally distorted as a result of the inadequate analysis of the cost of water to Applicant (and to the citizens in terms of replacement) and the secondary costs (e.g. treatment, replacement) of providing that water.

7. The DES refers to a "spokesman" for the City of Tulsa in §2.3. We request that the name of that person(s) be disclosed, pursuant to the full disclosure requirements of N.E.PA. and the Freedom of Information Act.

8. The DES fails to analyse the costs associated with the City of Tulsa requirement that Applicant indemnify and hold harmless the City for damages caused by Applicant in its operations. This is a requirement contained in the proposed contract for water supply.

9. The DES fails to analyse the impact or assess the costs arising out of the fact that the water contract is only for a term of 40 years. Consequently there is no supply of water assured or contemplated for decommissioning or for on-site storage of radioactive wastes after this contract period.

10. The DES fails to analyse the impact or assess the costs arising from the fact that Applicant's water use, when combined with its proposed needs for Northeastern, will result in there not being sufficient water for the citizens of Tulsa by approximately 1985. Furthermore, the City of Tulsa has not been successful in obtaining substitute water rights so as to be able to replace the water at any cost.

11. The DES fails to analyse the impact or assess the cost that will be imposed upon the citizens of Tulsa to replace the water used by Applicant for Black Fox alone, or in conjunction with Northeastern.

12. The DES fails to analyse the impact or assess the cost of water use based upon the "worst drouth of record" in lieu of some statistical figure such as the "50-year" drouth.

# Sierra Club

Comments: Tulsa Group Ok. Chap. Sierra Club
STN 50- 556; STN 50-557
page 3
September 3, 1976

B. The DES fails to examine energy conservation as an alternative to the project of this size. Specifically, but not exclusively, the DES fails to consider: (1) Conservation as a function of rates and rate design; (2) Conservation as a consequence of more efficient use or alternate products to achieve the same or similiar result; (3) Rationing or timed delivery or interruptable service; (4) Improved building codes; (5) The result of intensive public media conservation efforts such as have commonly occurred in the past when water supplies were low or critical.

C. The DES fails to adequately assess the impact and analyse the costs associated with the nuclear fuel cycle, specifically but not exclusively, that portion relating to disposal, storage, or other disposition of waste.

D. The DES fails to assess the implication upon projected demand of the inherent errors flowing from historical bases. By way of example: (1) Economic and social conditions now and in the future are substantially different from that existing in the past; (2) Prior demand was artifically stimulated by advertising and promotional allowances which are now prohibited by the Oklahoma Corporation Commission; (3) Prior growth was stimulated in large part by airconditioning and increases of demand as a result of this use will not be in effect to the same extent in the future; (4) Prior ecomomies of scale are no longer being realized and diseconomies are being experienced.

E. The off-system sales of all catagories made by Public Service Company are available to meet its presently projected demand. If the company were required to utilize this capacity for projected demand there would be no need for this project and any additional capacity could be met with coal or alternative forms of energy production such as wind or solar.

F. The DES fails to adequately address the implications of §208 of PL 92-500.

G. The DES fails to adequately address the impact of transmission facilities upon the Illinois River and its environs and upon the Bureau of Outdoor study for inclusion of the river into the national Wild and Scenic Rivers system.

H. The project is being constructed too close to population centers.

I. The cost-benefit analysis is grossly distorted because it fails to consider the fact that the citizens of the Tulsa area are being required to bear the total environmental harm yet would receive only a relatively small portion of the energy produced. Benefits to other areas of the country may not logically, economically, or morally be offset against detriment to a local area.

J. The releases of radioactive materials into the Verdigris as they affect the drinking water supply of downstream communitie has not been adequately assessed.

K. The DES fails to adequately monetize the environmental costs associated with the construction, operation and decommissioning of the project.

We request that the DES be withdrawn until such time as the deficiencies which are noted in these comments or in the comments of others are corrected.

Very truly yours,

Richard Croshong

Dr. Richard Croshong
Chairman, Tulsa Group
Oklahoma Chapter Sierra Club

1959 E. 33d Pl.
Tulsa, OK. 74105

(overleaf)





719 332

719 174

# CITIZENS ACTION for SAFE ENERGY, INC.

Promoting Energy Sources that are:
Non-Depleting, and
Non-Polluting

P. O. Box 924
Claremore, OK 74017


September 4, 1976



Director, Division of Site Safety &
Environmental Analysis
Office of Nuclear Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

RE: Public Service Company of Okla.
Docket # STN 50-556; STN 50-557

Dear Sirs:

Citizens' Action for Safe Energy, Inc. requests that it shall be made a part of the record of the proceedings in which reference is made above that we incorporate by reference and adopt the comments of the following individuals and organization concerning PSO Docket # STN 50-556 and STN 50-557: Mrs. Ilene H. Younghein; Dr. Richard Groshong, Chm., Tulsa Group, Oklahoma Chapter Sierra Club; and Mike A. Males (including the "Analysis of Public Service Company's Projections for Black Fox Nuclear Stations," by Mike A. Males and Marvin Cooke, August 22, 1976).

CASE also asserts every contention previously filed in the matter of the application of Public Service Company of Oklahoma STN 50-556 and STN 50-557. We feel that in view of recent developments and court decisions that those contentions denied by the NRC should be re-instated.

CASE requests that the DRAFT ENVIRONMENTAL STATEMENT be withdrawn until the deficiencies be corrected.

Sincerely,

*Carrie Dickerson*

Carrie Dickerson, Chm.
Citizens' Action for Safe Energy, Inc
P. O. Box 924
Claremore, OK 74017

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POOR ORIGINAL

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# CITIZENS' ACTION for SAFE ENERGY, INC.

Promoting Energy Sources that are:
Non-Depleting, and
Non-Polluting

P. O. Box 924
Claremore, OK 74017


September 5, 1976



Director, Division of Site Safety &
Environmental Analysis
Office of Nuclear Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

RE: Public Service Company of Oklahoma
Docket # STN 50-556; STN 50-557

Dear Sirs:

I wish to submit the following comments concerning the Draft Environmental Statement (PSO Docket # STN 50-556; STN 50-557). Please acknowledge receipt of these comments and make the comments a part of the record of the above proceedings.

A. Many considerations are lacking concerning the "Environmental Impacts of Plant Operation."

1. It is of interest to note that with expected maximum operation, 27,900 gallons per minute of makeup water will be taken from the Verdigris River, 24,000 gpm will be evaporated from the cooling towers, with the remainder eventually returned to the Verdigris River. Very inadequate coverage is given to the impact of following:

a. The effects of the cloud cover resulting from the evaporation of 24,000gpm of water--how it will affect the climate--temperature, rainfall, snow and ice, and what effect it will have on lack of sunshine on crops and other fauna and flora. Also, the aesthetic and sociological and psychological effects have not been fully assessed. The people--the inhabitants of Rogers and Mayes Counties-should be informed of this expected increase in cloud cover and what it will do to their farming operations and living patterns.

b. Not only will the excess moisture have an adverse affect on the inhabitants of surrounding areas for many miles, but the effluents carried by the evaporated water will have a definite effect on the people living in these areas. Have these people been fully informed about the fact that numerous radioactive elements will be carried with the moisture and deposited in the water, on the grass and other foliage and foodstuffs that these

9366

# CITIZENS' ACTION for SAFE ENERGY, INC.

Promoting Energy Sources that are:
Non-Depleting, and
Non-Polluting



Promoting non-polluting sources of energy:

Solar
Wind
Methane from
trash,
manure,
sewage,
algea
Hydrogen (by electrolysis)
Geothermal
Hydro (water)
Waves

radioactive elements will be concentrated up the food chain and through food, water and milk, will be concentrated in the tissues of the inhabitants. The Draft Environmental Statement cannot be complete until the people who will be affected have been informed of the consequences, and have been allowed to make an input. How many people know about the DES?

c. Have the inhabitants of Broken Arrow, Coweta, and Okay, and their water districts—the people who will be consuming the water from downstream of the proposed discharge site—been fully informed that the amount of water available for their usage will be decreased by some 24,000 gpm? And that the effluent released back into the river will contain radioactive elements that will concentrate in their tissues? Have they been informed of the consequences in case of a severe drouth—that their water supply will be decreased and the radioactive effluent into the water will be more concentrated? These people have a right to the truth!

d. Have the inhabitants been informed that many cases are on record in which unplanned discharges or releases of radioactive waste-water from the nuclear plants have increased the amount of radiation in the river water to above permissible-standards or levels—that the offending utility company was, in most cases, given a "slap on the hand," and allowed to continue operation? Not only radioactive releases, but unplanned releases of non-radioactive elements are not unusual.*(Refer to enclosed news clipping) Some recent unplanned discharges include 83,000 gallons of water containing tritium, a radioactive element, and a spill of from 500 to 700 gallons of sodium hypochlorite, a cl[illegible]ing agent, by the Vermont Yankee Nuclear Plant, into the Connecticut River. Also, November a small amount of radioactive [illegible] was dumped into this same river by the same plant!

e. Have the inhabitants of the area been informed of the expected increase in temperature of the Verdigris River water and of its effects on river biota? Have they been informed that in many instances the nuclear plant releases unplanned discharges of excessively heated water, raising the temperatures even higher? Have they been informed that in [illegible]

*News clipping: Nuke plant spill [illegible] oring law suit by Vermont, Greenfield (Mass.) Recorder, Aug. 5, 1976

# CITIZENS' ACTION for SAFE ENERGY, INC.

Promoting Energy Sources that are:
Non-Depleting, and
Non-Polluting

Directors:
Carrie Dickerson
Ilene Younghein
Doris Clark Gunn
Kevin Chambers
James Dickerson

Promoting non-polluting sources of energy:

Solar
Wind
Methane from
trash,
manure,
sewage,
algea
Hydrogen (by electrolysis)
Geothermal
Hydro (water)
Waves

other instances a utility company has been granted permission by a state agency to raise the river water temperature by a 13 degree Fahrenheit, as an ecological experiment!* So, NEPA and NRC standards mean nothing! The DES fails to discuss the effects of excess increase in water temperatures on the river biota, and the fact that unplanned and further planned releases can have a very detrimental effect on the plant and animal life of the river. This deficiency should be remedied before an FES is issued.

f. Have the farmers who use Verdigris River water from below the point of discharge from the proposed plant been informed of the planned and unplanned releases of both heated water and radioactive and non-radioactive effluents into the river? And do they know how much water per minute is planned to be removed from the river? And the consequences in case of a severe drouth? These people are entitled to be informed! What methods, if any, were used to educate these people? The DES cannot be complete without more information.

g. The DES has not considered the synergistic effects that may be achieved through the combination of the waste and pollution from the discharge of effluent from the sewage treatment plant (Tulsa) with the radioactive and non-radioactive discharge from the proposed nuclear plant, and how these synergistic actions may effect the consumers of the water downstream. In my estimation the entire DES is incomplete.

2. It is of great concern in the timeliness of the DES. The report was made available to the public in July 1976, and the comments to be made by Sept. 7, 1976. Such a short time span to fully research all the aspects of the report. And the fact that many alusions were made to the Environmental Report that was not available to but a few people! Added to the fact that many scientists who would have liked to make comments were away on summer vacations at this time! This makes one wonder if the timing were planned to prevent input from those who might view the report as deficient and incomplete in many aspects. It is my opinion that the DES is most unsatisfactory!

*Nuke to dump hot water, (News clipping) Greenfield Recorder, Aug., 1976

POOR ORIGINAL

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## CITIZENS' ACTION for SAFE ENERGY, INC.

Promoting Energy Sources that are:
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Directors:
Carrie Dickerson
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Methane from
trash,
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Geothermal
Hydro (water)
Waves

3. The DES fails to analyze the cost to the environment of the impact of dispension of ozone into the environment from the overhead transmission lines. Also, the loss of electricity from the lines and the effects of that electricity on the fauna and flora of the areas adjacent and under the lines. Also, the additional cost to the consumer who has to pay for the lost electricity. The alternative o. several local plants in strategic areas, rather than one large plant that requires many hundreds of miles more of additional lines, has not been considered.

4. The environmental impact of the whole fuel cycle has not been considered by the DES. The waste from the mining and milling (tailings) cannot be ignored and should be considered when counting the cost of nuclear power. Also, the cost should not be considered wholly in terms of dollars and cents. The cost in lives lost and maimed from cancer and genetic diseases from radiation has not been touched upon in the DES.* The reprocessing and final disposal of wastes has not been counted fully in the impact upon the cost and impact upon future generations for centuries to come. The DES cannot be complete without an inclusion of full disclosure of these costs both monetarily and environmentally for generations to come.**

5. Very unsatisfactory coverage has been given to decommissioning the plant. It is seriously doubtful that PSO has enough funds, nor will they have enough at the end of the lifetime of the proposed plant, to decommission the proposed plant satisfactorily. The enclosed news clipping** discusses a different approach to decommissioning--placing the costs at a much higher figure than PSO states. It is too late to consider decommissioning at the "operating license" stage! This is of too great importance to relegate to some later date. Now, during the "construction license" stage, this most important issue must be resolved. Otherwise, how do we know if PSO will be financially able to do the job correctly or satisfactorily--if there be such a method! We have allowed the NRC and the utilities to behave as ostriches too long--with their heads in the sand! The citizens who will be affected by the known and unknown problems of nuclear power plants must have the opportunity to make some of the decisions concerning their safety and welfare and the safety and welfare of their decendents for generations to come.

6. The DES fails to analyse or assess the costs to the health of the populace of the effects of the despersion of asbestos into the atmosphere from the cooling towers. This is another hazard that the population is not aware of. It is a well known fact that asbestos is cancer causing. The DES is incomplete in sti l another area.

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*Nuclear waste pile mushrooms, Tulsa Tribune, March 1976
**Nuclear waste disposal solution won't be cheap, Tulsa Tribune, March 12, 1976

## CITIZENS' ACTION for SAFE ENERGY, INC.

Promoting Energy Sources that are:
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Directors:
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Promoting non-polluting sources of energy:

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Methane from
trash,
manure,
sewage,
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Hydrogen (by electrolysis)
Geothermal
Hydro (water)
Waves

7. The statement is made concerning the low seismic activity in the area, which dismisses any problems with earthquakes. The DES is premature in its assessment of this facet. New findings show that indeed, there are potential problems with seismic activity. I suggest a greater in-depth study of this subject before dismissing it so perfunctly.

8. The problem of tornadoes was dismissed in the DES to be considered in the Safety report. This is another indication that the NRC and PSO are experts in the art of hiding their heads in the sand! In Oklahoma, we cannot postpone consideration of tornadoes. The DES is definitely incomplete. NOW is the time to make an in-depth study of this very definitely important phenomena in Oklahoma. This is a problem of our environment and can have severe repercussions and effects on the environment.

9. The subject of alternate resources is dismissed lightly. We have several alternatives to Nuclear Power in Oklahoma--a state richly blessed with sun and wind! Also, there is the very real and possible alternative--conservation of energy--which takes many different forms.* The DES will not be complete without an in-depth study of energy alternatives and including conservation of energy.

10. The DES refers to the Rasmussen Report in theorizing the low probability of a nuclear accident of any consequence. This report is under close scrutiny by eminent scientists today, who feel the methods used in attaining the conclusions were not reliable. Due to the fact that several very near accidents of very serious nature have occurred, it is my opinion that much more coverage and a wider opinion of experts be made. The DES is very unsatisfactory in this area.

11. Due to the fact that very few citizens knew about the DES and such a short time was allowed for comments to be made, and the fact that many who would have otherwise commented were on vacation at this time, it is my belief that the DES should be withdrawn. Add to the above the many deficiencies that I have listed, and you can understand why I request that the DES be withdrawn until such time that the deficiencies listed here and in others comments be corrected and the length of time and time of year for comments be changed.

Yours truly,

Cathy Coulson Currin

Cathy Coulson Currin, Chm.
Public Relations Committee
CASE

*The Atom Energy Role is Questioned, Tulsa World, May 16, 1976

POOR ORIGINAL

Tulsa World May 16, 1976

# Future Atom Energy Role Is Questioned

Greenfield (Mass.) Recorder Aug. 6, 1976

# Nuke plant spills bring law suit by Vermont

Unauthorized discharges into the Connecticut River could cost the Vermont Yankee Nuclear Power company up to $40,000 in fines, if the state of Vermont wins a court suit against its only nuclear power plant.

Atty. Gen. M. Jerome Diamond said the suit was filed Tuesday on behalf of the Agency of Environmental Conservation charging the utility with violating its discharge permit.

The case involves last month's leak of 83,000 gallons of water containing tritium, a radioactive chemical, a spill of from 300 to 700 gallons of sodium hypochlorite, a cleaning agent, last summer.

Diamond stated last summer that the state would not act "at this time" on what state officials say was a small amount of cobalt the plant dumped into the Connecticut River last November.

The legal action against Vermont is not so much out of concern that the two allegedly unauthorized spills into the Connecticut River may be hazardous to public health, but in an effort to enforce the law which prohibits all discharges which are not specifically authorized by a discharge permit.

The state makes no allegations about radioactivity levels in the discharges, according to a statement from the Attorney General's office. Vermont Yankee's discharge permit does set radioactive levels for certain authorized and planned discharges from the Vernon plant but since the state considered the two incidents "unplanned and accidental and in no way authorized by the discharge permit," "those radioactive limits are not at issue."

State officials have said the discharge of sodium hypochlorite on July 7, 1975 "contained no radioactivity that the state knows of." The discharge of 83,000 gallons of water containing tritium which is radioactive, the state believes caused "no serious threat to health".

The objective of the lawsuit which could cost Vermont Yankee up to $10,000 per day of violation is "to enforce the law which prohibits discharges without a permit, and to stop further [illegible] discharges at the Vernon Plant."

Diamond said the suit, filed in Washington County Superior Court asks that the fines be paid by Vermont Yankee's stockholders, not its rate payers.

Speaking at a news conference here, the attorney general said the lawsuit was designed to avoid "a confrontation" over a 1971 agreement in which Vermont Yankee agreed to abide by the state's health rules.

POOR ORIGINAL

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# Nuclear waste pile mushrooms

By JOHN [illegible]
Washington Post [illegible]

[illegible]

## Disposal site closed

[illegible]

The Salt Lake Tribune

business
oil
finance

TUESDAY, MARCH [illegible]

regional Greenfield Recorder Aug. 76

# Nuke to dump hot water

VERNON, Vt. — [illegible]

A-77

POOR ORIGINAL

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Waste disposal solution won't be cheap

POOR ORIGINAL

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6212DIN8,005,693

**PUBLIC SERVICE COMPANY OF OKLAHOMA**
A CENTRAL AND SOUTH WEST COMPANY

P.O. BOX 201 / TULSA, OKLAHOMA 74102 / (918) 583-3611

PSO

Public Service Company of Oklahoma
Black Fox Station
Comments on Draft Environmental Statement
Docket Nos. STN 50-556 and 50-557

September 7, 1976
File 6212.125.350C.21

SEP 13 1976

Mr. William H. Regan, Jr., Chief
Environmental Projects Branch 3
Div. of Site Safety and Environmental Analysis
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Regan:

Transmitted under cover of this letter are Public Service Company of Oklahoma's comments on NUREG-0088, "Draft Environmental Statement related to the construction of Black Fox Nuclear Generating Station, Units One and Two". The comments are arranged sequentially by page and section number for your convenience. If additional information is needed regarding these comments, we would appreciate your prompt inquiry.

Yours very truly,

B H Morphis

B. H. Morphis
Assistant Vice President - Nuclear

BHM:VLC:bp
Enclosure: Comments w/attachments

xc w/encl: (see attached list)

9331

CENTRAL AND SOUTH WEST SYSTEM

Central Power and Light, Corpus Christi, Texas · Public Service Company of Oklahoma, Tulsa, Oklahoma · Southwestern Electric Power, Shreveport, Louisiana · West Texas Utilities, Abilene, Texas

Copies to:

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2536 East 51st Street
Tulsa, Oklahoma 74105



PUBLIC SERVICE COMPANY OF OKLAHOMA

COMMENTS ON THE DRAFT ENVIRONMENTAL STATEMENT
FOR BLACK FOX STATION

DOCKET NOS. STN 50-556; 50-557

SUMMARY AND CONCLUSIONS

| | | |
|---|---|---|
| Page i | Section 3a | The land use acreages have been revised. See ER, Supplement 3. |
| Page i | Section 3e | There is no basis for the statement that previously undiscovered archaeological resources are likely to be encountered along the transmission line corridor. |

TABLE OF CONTENTS

| | | |
|---|---|---|
| Page vi | Section 9.3.8 | This description does not appear in the DES text. |

1.0 INTRODUCTION

| | | |
|---|---|---|
| Page 1-1 | Section 1.1, Paragraph 1 | The BFS ER Section 2.1.3.2 indicates that "the nearest boundary of the densely populated area of Tulsa....is located 13 miles west of the site" compared to the DES statement that "the proposed facilities are to be located on the applicant's site....approximately 12 miles east of the Tulsa city limits". |

2.0 THE SITE AND ENVIRONS

| | | |
|---|---|---|
| Page 2-1 | Table 2.1 | The land use figures have been revised. See ER, Supplement 3. |
| Page 2-3 | Figure 2.2 | This figure has been revised. See ER, Supplement 3. |
| Page 2-7 | Figure 2.5 | Ibid. |
| Page 2-20 | Figure 2.12 | Ibid. |
| Page 2-28 | Section 2.6.3 | The fourth sentence should be reworded hence: "Hurricanes are not expected to affect the BFS site as their effects are normally negligible beyond a distance of 100 kilometers from the Gulf Coast". |
| Page 2-41 | Section 2.8.2, Paragraph 3 | The DES states that "Currently there is a proposal for an industrial park three miles northeast of the site adjacent to Highway 33". This statement is not entirely correct. The industrial park location was developed from information contained in the Community Development Plan for Inola, Oklahoma dated June 1974 and developed by the Northeast Counties of Oklahoma Economic Development Association. |

| | | |
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| | | This information suggested criteria for an industrial park if such need was ever shown to be apparent for one in the Inola vicinity. From this information, the location described and shown on DES Figure 2.5 was developed as a potential site. Hence there is no actual proposal. |
| Page 2-41 | Section 2.9.1 | "One historic cemetery is located in the southern portion of the station and two other...." The word "station" should be changed to the word "site". The cemetery is outside the construction area. |

## 3.0 THE STATION

| | | |
|---|---|---|
| Page 3-1 | Section 3.2, Paragraph 2 | "....mixed with uranium dioxides as a burnable fuel." The word "fuel" should be changed to the word "poison". |
| Page 3-1 | Section 3.3, all paragraphs | Information pertinent to this section has been revised. See ER, Supplement 3. |
| Page 3-2 | Figure 3.1 | Ibid. |
| Page 3-3 | Figure 3.2 | Ibid. |
| Page 3-4 | Table 3.1 | Ibid. |
| Page 3-5 | Section 3.4.3, Paragraph 1 | "....and from chemicals added to prevent fouling and corrosion." The words "fouling and corrosion" should be replaced with the word "scaling" per EPA limitations. |
| Page 3-8 | Section 3.4.4 | PSO has modified the design of the station intake structure. This design information will be filed in the next Environmental Report supplement. |
| Page 3-9 | Figure 3.5 | Ibid. |
| Page 3-8 | Section 3.5, Paragraph 5 | The DES states: "In a letter dated June 22, 1976, however, the applicant committed to design and construct the Black Fox Station Units 1 and 2 with such filtration equipment as may be necessary to prevent radioactive materials and gaseous effluents from exceeding the design objectives of 10CFR50, Appendix I, as determined by the staff's evaluation." PSO categorically disagrees with the interpretation of that letter. A correct statement would be: "In a letter dated June 22, 1976, however, the applicant committed to design and construct Black Fox Station Units 1 and 2 with such filtration and equipment as may be proven to be necessary to prevent radioactive materials and gaseous effluents from exceeding the design objectives of 10CFR50, Appendix I." We did not, in that letter, give the staff license to determine station design by dictating what plant equipment we must install to meet Appendix I. The staff also incorrectly infers that we are no longer utilizing the source terms in the General Electric |



| | | |
|---|---|---|
| | | Company Topical Report NEDO 21159. PSO's letter did not withdraw the use of this document from the Black Fox docket which, in fact, forms an integral part of our source term calculations. |
| Page 3-11 | Section 3.5.1 | PSO has modified the design of the liquid radwaste system as discussed with the staff August 12, 1976. Design details will be formally submitted in the next ER supplement. |
| Page 3-13 | Section 3.5.1.4, Paragraph 1 | In the last sentence, the staff notes that "the principal difference between the staff's release estimate and that of the applicant is that the staff's has been adjusted for anticipated operational occurrences". We wish to note that the BFS calculations have also included these unanticipated operational releases as discussed with the staff in our meeting of April 15, 1976. The BFS radwaste system is designed to reduce the radiological consequences of unanticipated operational releases. A conservative estimate of the radioactivity released in unanticipated occurrences was included in the annual release of .009 curies per year. Of the staff's estimate of 0.17 curie per year per reactor releases, it should be noted that 0.15 curies per year is allocated for the abnormal occurrences which is far in excess of our total annual release estimate of .009 curies per year and makes no allowance for the severance of connections between liquid tanks which effectively halved the potential for inadvertent releases. PSO believes that discharge of 0.15 curies assumed by the staff is unrealistic for the Black Fox Station radwaste system. |
| Page 3-14 | Figure 3.7 | The two-stage air ejectors leading from the main condenser to the offgas treatment system should be shown as three-stage. Also the indicated charcoal adsorbers and HEPA filters shown as being committed to by PSO is not correct. Public Service Company committed to such filtration as may be proven to be necessary. No such proof has been demonstrated for any or all of the lines shown. |
| Page 3-15 | Section 3.5.2.1 | The disparity between the staff's calculations and PSO's is due to the use of different source terms. See our comment for Section 3.5. |
| Page 3-15 | Section 3.5.2.2, Section 3.5.2.3, Section 3.5.2.4. | Ibid. Ibid. Ibid. |
| Page 3-16 | Section 3.6.1.1 | Approximately 19,100 pounds of acid are to be added per day for both units. |
| Page 3-18 | Table 3.6 | The corresponding ER table has been revised. See Supplement 3. |

| | | |
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| Page 3-13 | Section 3.6.1.1, Paragraph 3 | Attachment 1 describes the toxicity of both the polyolester and the phosphonate material as well as their biodegradability. |
| Page 3-19 | Section 3.6.1.2, Paragraph 2 | "....and decanted water will be <u>discharged to the waste water holding pond</u>." |
| Page 3-19 | Section 3.6.1.3 | "....and the composition is given in Table <u>3.6</u>. . Approximately <u>230</u> pounds per day of NaOH and <u>590</u> pounds of $H_2SO_4$....and then discharged at the rate of <u>18</u> gpm to the waste water holding pond. |
| Page 3-20 | Section 3.6.1.4, Paragraph 1 | The chlorine gas will be injected into the station service water pump suction. The chlorinated water will then be circulated through the station service water system with excess returned to the presettling pond. |
| Page 3-20 | Section 3.6.1.4, Paragraph 3 | The waste water holding pond has a <u>minimum</u> retention time of 24 hours, rather than a mean time of 24 hours. |
| Page 3-21 | Table 3.8 | This table has been revised. See Environmental Report, Supplement 3. |
| Page 3 25 | Figure 3.8 | This figure has been revised. See ER, Supplement 3. |
| Page 3-27 | Table 3.11 | Line name - BFS to <u>Northeastern</u>. Scheduled completion date of the <u>BFS-Catoosa line</u> 138 kv is 1976 rather than 1976. |

## 4.0 ENVIRONMENTAL IMPACTS OF CONSTRUCTION

| | | |
|---|---|---|
| Page 4-1 | Section 4.1.1.1, Paragraph 4 | The staff requirements in the 4th paragraph of annual inspections of the draw between the central complex and the waste water holding pond will not be necessary. PSO, in order to minimize the adverse effects on the environment, will consider the potentials for erosion within this drainage feature and provide appropriate protection as determined by design. |
| Page 4-5 | Section 4.1.1.2, Paragraph 1 | The existing pond will be enlarged to about <u>45</u> acres for the presettling pond. |
| Page 4-5 | Section 4.1.1.3 | The holding pond elevation will change to <u>558</u> feet MSL. |
| Page 4-5 | Section 4.1.1.4, Paragraph 1 | The staff proposes to require that procedures set forth in 36CFR800 be carried out. However, the cemetery does not appear to meet National Register criteria. 36CFR800.10(b) states that ordinary cemeteries....shall not be considered eligible for the National Register. Such cemeteries will qualify if they are integral parts of districts that do meet the criteria or if they fall within the following categories. A cemetery which derives its primary significance from graves of persons of transcendent importance, from age, from distinctive design features, or from association with historic events. While the cemetery has been termed a historic site, we do not feel that the cemetery qualifies by any of the criteria quoted above. Moreover, the station will not affect the cemetery as the construction area does not intrude upon the cemetery site. |
| Page 4-5 | Section 4.1.1.4, Paragraph 3 | The staff requires that "all archaeological sites must be investigated below the plow zone or 'A' horizon for occupational debris and evidence of prehistoric settlement remains". ER Section 2.6.2 states that there are 3 archaeological sites within the BFS site boundary. These sites are not in areas of planned construction. Furthermore, it was the Oklahoma Archaeological Survey that stated in a report to Black & Veatch Consulting Engineers, who were acting in behalf of PSO, that the sites are relatively insignificant since little else can be achieved through additional archaeological research. There is no evidence to indicate the likelihood of significant archaeological sites, and to justify the need for additional archaeological research. The staff also indicates that they will require PSO to retain a qualified archaeologist during station construction phase to aid in the identification and preservation of historic and prehistoric cultural resources. PSO believes this requirement unnecessary, and resists this unwarranted expenditure, in light of the type of archaeological resources found in the area and our past coordination with the Oklahoma State Archaeological Survey. |
| Page 4-6 | Section 4.1.2.1, Paragraph 2 | The staff expresses concern about oil leakage into spoils. As indicated in the Black Fox Station Preliminary Safety Analysis Report and in the Environmental Report, these wells will be plugged and abandoned in accordance with Oklahoma Corporation Commission rules, the governing regulatory agency. Hence, appropriate preventive measures will have been taken. |
| Page 4-6 | Section 4.1.2.1, Paragraph 3 | The staff requires that prior to initiation of construction activities PSO supply the routing and design for transporting water from the intake structure to the presettling pond for staff analysis and approval. Revisions to the Environmental Report reflecting changes in the intake structure design as announced earlier will include routing and design of piping from the intake structure to the presettling pond. |
| Page 4-6 | Section 4.1.2.2 | ....structure via a 70 <u>foot</u>-wide ________ channel.... |

| | | |
|---|---|---|
| Page 4-6 | Section 4.1.2.3, Paragraph 2 | Description of the railroad spur and site access roads. This information has been revised. See Environmental Report, Supplement 3. |
| Page 4-7 | Section 4.1.3, Paragraph 4 & 7 | The staff requires that the routing of the transmission lines be inspected by a qualified biologist. PSO believes this requirement to be unduly severe for the nature of the right-of-way. Staff also requires that an archaeological and historic site survey be made for all areas where tower bases are to be located, where roads are to be built, and where transmission line construction will disturb existing soil cover. PSO believes that the commitment, ER Section 3.9.4.2, to have the staked routes reviewed by personnel certified by the State Historic Preservation Officer who interacts with the Oklahoma Archaeological Survey in these matters is more than adequate. |
| Page 4-9 | Section 4.3.1.1, Paragraph 4 | Staff recommends that several specific areas be planted with sprigged bermuda grass. PSO believes that other planting methods may be equally suitable. |
| Page 4-11 | Section 4.3.2.2, Paragraph 3 | The staff has required runoff from spoils-deposit areas to be monitored to ensure that suspended solids limitations are met. The limitations of 50 mg/per liter total suspended solids is applicable to rainfall runoff waste water sources only in the vicinity of the generating unit and related equipment. It appears that the limitations are not applicable to runoff from the spoils deposit area. "Runoff from other parts of the site is not intended to be covered by this limitation." (<u>Development Document Steam Electric Power Generating, p. 412</u>) In addition, in a recent court decision <u>Appalachia Power Company et al v. Train</u>, the court ruled that EPA has no authority to compel the industry to collect rainfall runoff not normally routed into a point source collection system, from construction or material storage areas, and remanded EPA's rainfall runoff regulations.<br><br>The U. S. Army Corps of Engineers conduct maintenance dredging along the Verdigris River as described in the ER response to NRC Question 2.9. The Tulsa District was recontacted to ascertain their monitoring practice.* They indicated that no monitoring (other than visual monitoring for erosion) has ever been conducted for either spoil removal runoff or rain runoff from spoil-deposit areas. For these reasons, we believe that the monitoring requirement should be withdrawn. |

*Telephone communication on July 29, 1976 from Larry Hogue, U. S. Army Corps of Engineers, Tulsa District, to M. W. Kaufman, Black & Veatch.



| | | |
|---|---|---|
| Page 4-13 | Section 4.4.1, Paragraph 2 | The information regarding noise impact has been revised. See Environmental Report, Supplement 3. |
| Page 4-17 | Section 4.4.4, Paragraph 6 | Ground Valley Hospital should be Grand Valley Hospital. |
| Page 4-18 | Section 4.4.4, Paragraph 6 | The staff indicates that it believes it would be desirable for the applicant to establish a set of socio-economic impact mitigation programs in coordination with local governments and planning agencies. Public Service Company, as practice, has and will continue to monitor local community impacts in areas in and about those in which it is constructing facilities, both major and minor. Public Service Company has committed to taking those actions that will minimize the socio-economic impact on the surrounding community and will remain flexible in this regard. |
| Page 4-19 | Section 4.5.1.1 | PSO concurs that these commitments are as stated in the Environmental Report. |
| Page 4-20 | Section 4.5.1.1 | Item 23 - The page should be 4.2-9 rather than 4.2-5. Otherwise, PSO concurs that these commitments are as stated in the Environmental Report. |
| Pages 4-20 & 4-21 | Section 4.5.1.2 | PSO concurs that these commitments are as stated in the Environmental Report. |
| Page 4-21 | Section 4.5.2.1 | Item 1 - PSO will comply. Item 2 - PSO will comply. Item 3 - Refer to previous comments - Section 4.1.1.1. Item 4 - Refer to previous comments - Section 4.1.2.1. Item 5 - PSO will comply. Item 6 - PSO believes that this requirement of an onsite biologist is unduly severe in light of previous commitments and nature of the environment in the construction and transmission area and the requirements seek to impose needless duplication of personnel. Item 7 - Refer to previous comment - Section 4.1.3. |
| Page 4-21 & 4-22 | Section 4.5.2.2 | Item 1 - PSO will comply. Item 2 - PSO will comply. Item 3 - PSO will comply. Item 4 - See previous comments - Section 4.3.2.2. Item 5 - PSO will comply. Item 6 - PSO believes that this device is not warranted. Item 7 - PSO will comply. Item 8 - PSO will comply. Item 9 - PSO will comply. |

<u>5.0 ENVIRONMENTAL IMPACT OF PLANT OPERATION</u>

| | | |
|---|---|---|
| Page 5-1 | Section 5.1, Paragraph 2 | This information has changed since the submittal of Supplement 0 to the Environmental Report and will be corrected in an upcoming supplement. There are presently two producing gas wells on the site, one located in the Northeast Quarter of Section 24, Township 19 North, Range 16 East. The other in the Southwest Quarter of Section 18, Township 19 North, Range 16 East. There is also a producing oil well |

| | | |
|---|---|---|
| | | onsite located in the Northwest Quarter of Section 13 and two producing oil wells located in the Northeast Quarter of the Northeast Quarter of Section 23. All of the oil wells are in Township 19 North, Range 16 East. Each of the oil and gas wells will be plugged and abandoned in compliance with the regulations of the Oklahoma Corporation Commission prior to commencement of construction. This information was supplied in response to PSAR Question 310.16. |
| Page 5-1 | Section 5.1, Paragraph 3 | It was stated that 10 single family residences will have to be abandoned and that the residents of these will have to relocate. We note that only 5 of these residences were occupied at the time of their purchase for the Black Fox Station. |
| Page 5-16 | Section 5.4.1.2, Paragraph 1 | The staff has chosen to calculate the individual radiation dose based upon the infant receptor using filters. This procedure is more restrictive than required by NRC regulations and assumes filters which have not been committed to by PSO. PSO calculations using exact NRC methodology without filters shows BFS (without filters on containment ventilation, auxiliary building and mechanical vacuum pump) meeting Appendix I for the child receptor.<br><br>PSO insists that the evaluation of exposures should be based upon receptors actually existing at locations indicated. 10CFR50 Appendix I in Section III implementation states: "For determination of design objectives in accordance with the guidelines of Section II, the estimation of exposure shall be made with respect to such potential land and water usage and food pathways as could actually exist during the term of plant operation. Provided, that, if the requirements of paragraph B of Section III are fulfilled, the applicant shall be deemed to have complied with the requirements of paragraph C of Section II with respect to radioactive iodine if estimations of exposure are made on the basis of such food pathways and individual receptors as actually exist at the time the plant is licensed."<br><br>Paragraph C of Section II states the 15 mrem/yr limit. Paragraph B of Section III sets requirements for monitoring and surveillance program to keep track of changes in food and water pathways which the BFS ER has committed to. Hence, it is the PSO contention that the BFS meets Appendix I without filters. |



| | | |
|---|---|---|
| Page 5-16 | Table 5.5 | Ibid. |
| Page 5-20 | Table 5.7 | The distance to the nearest drinking water intake is approximately 6300 feet rather than 3 miles downstream as shown to the Broken Arrow water intake. ER Subsection 5.2.2.1. |
| Page 5-24 | Table 5.11 | Under the heading Criterion, radioiodine and particulates dose to any organ from all pathways - The calculated dose should be in the order of 6.3 mrem per year using the existing child rather than the assumed infant. See comment above, Section 5.4.1.2. |
| Page 5-27 | Section 5.5.1.1, Paragraph 3 | The comment referring to BFS discharge exceeding state standards is incorrect in that in Table 5.15 the guidelines shown are for point source discharge rather than in-stream standards, as is the case. Further, the Verdigris River isn't an intermittent stream as described in footnote "c". |
| Page 5-27 | Section 5.5.1.1, Paragraph 5 | The staff has required PSO to show to their satisfaction before the plant is operated that the inhibitors to be used will not have an adverse effect on the river and will not be toxic. Toxicity and biodegradability data provided by vendors of typical anti-scalants are given in Attachment 1. PSO would like to clarify the intent of the NRC and discuss the differences between their staff position and the position of the EPA. It should be recognized that the information on the exact mechanism of reactions of the various proprietary organic scale inhibitors is not known. The impacts of organic phosphates in the turbid waters of the Verdigris River is expected to produce only minimal adverse impacts. |
| Page 5-27 | Section 5.5.1.2 | The staff states that "the EPA will require chemical monitoring of in-plant waste sources prior to mixing in the waste water holding pond". PSO does not agree that this is proper. We recommend that this sentence be removed from the section and that the Environmental Protection Agency should only evaluate the station as a point source. |
| Page 5-29 | Table 5.15 | This table was developed from river water analyses presented in the BFS ER Table 2.4-12 and 2.4-13. The discharge concentrations shown in the tables were calculated as stated in Section 5.5.1.3, "with the exception of Cr and Ni which originates from the corrosion of stainless steel condenser tubes. The concentration of trace substances resulted from the ninefold concentration of river water in the cooling system." Although the table seems to indicate that the referenced discharge is from |

the waste water holding pond to the river, the waste stream is actually only the blowdown from the cooling towers. During normal operation, the cooling tower blowdown represents 83% of the total waste water flow into the pond and 86% of the effluent from the waste water holding pond to the river. Assuming that the trace metal concentrations of the other waste streams entering the waste water holding pond are equal to the concentrations in the river water, the following changes should be made to DES Table 5.15 based on blowdown comprising 83% of the total waste water discharge to the pond.

| Element | Discharge Concentration - Mg/l DES Value | Recomputed Value |
|---|---|---|
| As | 0.22 | 0.19 |
| Ba | 8.0 | 6.4 |
| Cd | 0.2 | 0.17 |
| Cu | 0.05 | 0.04 |
| F | 2.7 | 2.3 |
| Fe | 4.5 | 3.8 |
| Pb | 0.8 | 0.6 |
| Mn | 0.2 | 0.13 |
| Hg | 0.02 | 0.013 |
| Zn | 0.7 | 0.6 |

As stated on DES Page 5-27, and in DES Table 5.15, the concentration of trace elements in the station effluent are compared with state waste water guidelines for intermittent streams and storm sewers. As pointed out in our comments above to Section 5.5.1.1, paragraph 3, the comparison should be to the in-stream standards rather than to the point source discharge standards.

| | | |
|---|---|---|
| Page 5-34 | Section 5.6.2.2, Paragraph 7 | Re polyolesters and/or phosphonate, refer to previous comments on this subject. |
| Page 5-35 | Section 5.6.2.2, Paragraph 1 | Re polyolesters/phosphonates, refer to previous comments on this subject. |
| Page 5-35 | Section 5.7, Paragraph 3 | The staff requirement that all new chicken barns, metal buildings, and fences under or near (.1 km) transmission lines be inspected for induced currents after lines are placed in service is unduly restrictive in light of historical experience and present PSO engineering practice. PSO presently checks all such structures within the line right-of-way (for example 150' total width, 345 kv) and directly adjacent. We have found that distances in the order of 30 meters from line to structure offer no hazard except for unusually large buildings which are treated as special cases. |







6.0 ENVIRONMENTAL MONITORING PROGRAMS

| | | |
|---|---|---|
| Page 6-1 | Section 6.1.3, Paragraph 3 | The parameters to be analyzed in the sampling stations are satisfactory after the plant is in operation. However, we do not agree that the analyses should begin prior to the construction of or during construction of the plant. Nor do we concur with the establishment of a new monitoring station. We believe that sampling need not commence until one year prior to commercial operation of the plant. During the construction stage, we believe that a check of points 1, 2 and 4 for the following items: Calcium, Magnesium, Alkalinity, Dissolved Solids, Suspended Solids, Nitrate, Temperature, pH, Dissolved Oxygen, Specific Conductivity, Phosphate, Chloride, Sulfate, and Silica on a monthly schedule is sufficient. |

7.0 ENVIRONMENTAL IMPACT OF POSTULATED ACCIDENTS INVOLVING RADIOACTIVE MATERIALS

PSO has no comments on this section of the Draft Environmental Statement.

8.0 THE NEED FOR THE PLANT

| | | |
|---|---|---|
| Page 8-3 | Section 8.1.2 | The staff states that PSO purchased energy from GRDA during PSO's peak. This is a misinterpretation of the FPC report. 1,512,167 MWH were metered to PSO during 1974 and 1,512,167 MWH were metered to the GRDA. This is a measure of energy flow on the interconnections and includes sales, interchange, and inadvertent energy flow. PSO does not purchase energy from GRDA as their system is annually deficient in energy output.<br><br>Identification of the MO-KAN-OK 345 kv Agreement as the Missouri Participation Agreement is incorrect. Also, it is incorrect to state that the MO-KAN-OK 345 kv Agreement provides for first call-on emergency energy - emergency energy options in this Agreement are for pricing only and carry no priority over emergency agreements in any other agreement. |
| Page 8-3 | Section 8.2.1 | The staff states that in 1974, 58% of energy was delivered at retail and 35% was transferred to other utilities for resale. It should be noted that 23% of generated energy was transferred to other utilities under contract and that 12% was transferred during emergencies and as economy energy to assist neighboring utilities when such energy was available from PSO. |
| Page 8-8 | Section 8.2.1, Paragraph 8 and Section 8.2.2, Paragraph 1 | Reference is made to liquid natural gas (LNG). The correct fuel is liquified petroleum gas (LPG). |

Page 8-13 — Section 8.2.3.1

PSO questions the staff conclusion that our regional growth and demand will be the same as the national average. Historically the south central demand growth rate has exceeded the national average and we have seen no projections that suggest change in this trend, especially when general movement, industrial growth, and minimum unemployment are most prevalent in the south central region. It should be recognized by the staff that the use of electric energy per capita is higher than average in this south central area.

Page 8-13 — Section 8.2.3.2

PSO seriously questions that the population in Oklahoma will grow more slowly than the national average. We also believe strongly that employment in petroleum extraction will increase as the price of petroleum increases. Staff suggests that peak load will grow at the same rate as the average hourly load. In spite of great effort on the part of utility management, we have not been able to turn around the declining load factor since the introduction of air conditioning. Industry as a whole continues to forecast demand growth rates increasing at a greater rate than the growth in energy use in the Oklahoma service area.

Page 8-17 — Section 8.3.1

The staff bases its need for BFS on the assumption that only BFS is subject to delay in construction schedule and all other planned capacity additions are firm. PSO has for example, since publication of this information in the Environmental Report in 1975, revised its capacity addition planning and deferred 240 mw previously planned for 1982. As stated in our letter of transmittal for Environmental Report, Supplement 4, and Application for Licenses, Amendment 1, filed August 20, 1976, PSO anticipates that a general updating of th. category of information will be filed in behalf of all BFS participants later this year.

Page 8-22 — Table 8.10

The staff has incorrectly credited PSO with 847 megawatts in each BFS unit when the ER specifically advises that 147 megawatts in each unit will be owned by others. At this date and in the letter of transmittal dated August 20, 1976 referenced in the response above, we filed supplementary information indicating that Western Farmers Electric Cooperative is an owner of the 147 megawatts. Thus, the capacity planned by PSO as of July 1976 for 1983 is 4517 megawatts (3895 plus 700 minus 78) and for 1985 is 5217 megawatts. Staff's method of calculating reserves is illustrated in Table 8.10 and is inaccurate since it does not recognize the obligations of PSO with respect to contract purchases



and sales. Correct analyses which credit firm purchases to the load forecast to calculate demand responsibility and discounting generating capability for contract sales without reserves provides a dependable measure of reserve forecast. The attached corrected Table 8.10 shows the forecast reserves using PSO's 1975 forecast and the staff's forecast.

Page 8-17 to 8-26 — Section 8.3.1

PSO's discussion of forecast load and reserves call attention to the load growth of GRDA which is not provided for by planned capacity additions by PSO or GRDA. If additional capacity is not installed for GRDA's load, their customers will draw power from adjacent utilities. If all this capacity deficiency is drawn from PSO, reserves in 1983 will be reduced 248 megawatts (6.8%) and 497 megawatts in 1985 (11.7%) using PSO projections. Using staff's 6.4% load growth projection, GRDA's burden on PSO would reduce PSO's reserve 120 megawatts (3.9%) in 1983 and 220 megawatts (6.2%) in 1985.

In view of the uncertainty of load requirements and the need to reduce the use of natural gas and fuel oil for electric generation, it appears unwise to plan now to delay construction of BFS. Paragraph 3 implies that natural gas may be available for baseload operation. It seems inconsistent to base requirements on FEA projections of low growth rates and at the same time fail to recognize that natural gas will not be available for baseload generation.

Page 8-26 — Section 8.4

Nuclear capacity and energy have been demonstrated to be more economic than coal generation, both in the BFS Environmental Report and in other authoritative sources. This, coupled with our comments above on the need to reduce the use of natural gas and fuel oil for electric generation, leads us to concur with the staff's statement that "this need (i.e., the conservation of vital natural resources) can be fulfilled by the prompt construction of non-gas burning baseload capacity such as the proposed Black Fox Station". See attachment 3.

## 9.0 ALTERNATIVES

Page 9-1 — Section 9.1.1

Following the staff's scenario of conservation and limited growth by PSO's customers, it follows that BFS should not be delayed since nuclear is the preferred generating source. Refer to previous comments.

Page 9-3 — Section 9.1.2.1

PSO will have the ability at its Northeastern 3 and 4 coal stations now under construction to burn municipal waste. The waste available in the vicinity will be less than 5% of the needed boiler fuel.

**Page 9-8** | **Section 9.2.4**

The staff has stated that the proposed routing in the northern corridor of the western study area crosses unique habitat (including a potential nesting habitat of the southern bald eagle) just off the BFS site. This unique habitat as described by the staff on Page 2-28 and located on Figure 2.14 of the DES is mesic upland woods. The staff recommends that the alternate transmission route be used in order to avoid crossing the habitat.

Examination of the aerial photographs shows that the transmission line does not cross a site habitat depicted as mesic upland woods. The line does cross through the habitat depicted as upland woods (B) and not designated as mesic or xeric. The wooded areas northwest of the site around Commodore Creek have not been identified as mesic upland woods. Therefore, the transmission line does not traverse any known mesic upland wood habitat. The staff apparently is basing the comment concerning the potential southern bald eagle habitat on a statement which appears in the ER, Section 2.2 (p. 2.2-65). "If there is a future increase in the nationwide breeding population it is possible that this species (southern bald eagle) could again nest in the site vicinity". The preferred nesting habitat of the southern bald eagle is tall riparian woodland (Snow, Carol. 1973. Habitat Management Series for Endangered Species Report 6, "Southern bald eagle and Northern bald eagle". Bureau of Land Management. U. S. Department of the Interior. Technical Note) Although areas of this habitat do occur in the site vicinity, it appears that the routing of the northwest transmission line does not traverse any of this habitat; and therefore could not be considered to have a significant impact on potential southern bald eagle nesting sites.

In summary, it does not seem reasonable that the alternate (B) northwest transmission line corridor be selected on the basis of avoiding mesic upland woods or southern bald eagle nesting areas, since it appears that neither of these is known or actually occurs in the proposed right-of-way. Refer to Attachment 4: aerial photos of this area of the BFS-Catoosa line, feeder 81-526. It may also be seen that residential encroachment is prevalent in the subject area.



**Page 9-11** | **Section 9.3.1.3**

First paragraph, second line. The word "county" should be "country".

**Page 9-14** | **Section 9.3.5, Paragraph 6**

Re use of organic scale inhibitors, please refer to our earlier comments on this subject.

## 10.0 EVALUATION OF THE PROPOSED ACTION

**Page 10-1** | **Section 10.1.1.2, Paragraph 1**

A more nearly correct statement is that all water for station use will come from the Oologah Reservoir via the Verdigris River.

NALCO

Attachment 1

## TOXICITY INFORMATION

### NALCO 344

| | |
|---|---|
| B.O.D. | 1.02% |
| C.O.D. | 15.8% |
| $LD_{50}$ (Guppies) | 2500-3000 ppm |
| $LD_{50}$ (Zebras) | 2500-3000 ppm |
| Acute Oral $LD_{50}$ (Rats) | 4.6g/kg. body wt. |
| Acute Vapor Inhalation | |
| $LC_{50}$ (Rats) | 21 Mg/Liter air |
| Acute Dermal $LD_{50}$ (Rabbits) | >10.2g/kg. body wt. |
| Eye Irritation (Rabbits) | Extreme |
| Skin Irritation (Rabbits) | Extreme |
| Biodegradable | |

### NALCO 345

| | |
|---|---|
| B.O.D. | 46% |
| C.O.D. | 59.7% |
| $LD_{50}$ (Guppies) | >8,000 ppm |
| Acute Oral $LD_{50}$ (Rats) | 28.2 grams/kg. body wt. |
| Acute Vapor Inhalation | |
| $LC_{50}$ (Rats) | >13 Mg/Liter air |
| Acute Dermal | |
| $LD_{50}$ (Rabbits) | >10.2 g/kg. |
| Eye Irritation (Rabbits) | None |
| Skin Irritation (Rabbits) | None |
| Biodegradable | |

Note: $LD_{50}$ means lethal dosage for 50% of species tested.
$LC_{50}$ means lethal concentration for 50% of species tested.
Table Salt - Acute Oral $LD_{50}$ (Rats) - 4g/kg. body wt.

NALCO CHEMICAL COMPANY

## NALCO CHEMICAL COMPANY
### Product Environmental Information File

PRODUCT NO. 345 PRINCIPAL USE Cooling Nator Chemical

SICAL PROPERTIES: ______ Max. recommended product dosage level 50 ppm

Physical Form ______ Color ______ Odor ______

Specific Gravity @ ______ °F = ______ Density ______

Viscosity @ ______ °F = ______ cp pH of 1% solution ______

Flash Point ______ °C or °F by ______ Method

Other ______

| | Species | TLm | | | |
|---|---|---|---|---|---|
| Fish Toxicity: | Guppies | | ppm | | hr |
| | Zebras | | ppm | | hr |
| | Trout | >100<1000 | ppm | 96 | hr |
| | Bluegills | >100<1000 | ppm | 96 | hr |

BOD (5 Day) ppm product used to determine BOD 25 5 Day BOD 4.3 ppm
= BOD at use level 8.6 ppm. 600,000 (max use level) = 30 pgm

Total heavy metal content by combined APDC extraction — emission spectrographic analysis = 7.68 ppm ($10^{-6}$) in product

Calculated total heavy metal content in treated water system
Max. recommended product dosage of 50 ppm ($10^{-6}$) X total heavy metals in procuit of 7.68 ppm ($10^{-6}$)
quals maximum calculated level of heavy metals in treated system of .000384 ppm ~~xxxx~~

This product contains ______ (ppm) (%) heavy metals as an active ingredient which is not included in the following analysis:

EMISSION SPECTROGRAPHIC BREAKDOWN OF TOTAL HEAVY METAL CONTENT BY ELEMENT

| Element | ppm of element in product | Min. detectable limit of test (ppm) | Calculated maximum level of element in treated system (ppm) |
|---|---|---|---|
| Antimony | | <.02 | |
| Arsenic | | <.05 | |
| Bismuth | | <.01 | |
| Cadmium | | <.01 | |
| Chromium | | <.01 | |
| Cobalt | | <.01 | |
| Copper | 0.08 | <.01 | .000004 |
| Iron | | <.01 | |
| Lead | | <.02 | |
| Manganese | | <.01 | |
| Mercury | | <.01 | |
| Molybdenum | 7.0 | <.01 | .00035 |
| Nickel | | <.01 | |
| ...ium | | <10 | |
| Silver | | <.01 | |
| Tin | | <.01 | |
| Tungsten | | <.05 | |
| Vanadium | | <.01 | |
| Zinc | 0.6 | <.03 | .00003 |

POOR ORIGINAL

TABLE VI

Fish Toxicity of the DEQUEST Products

| | DEQUEST 2000 | DEQUEST 2010 | | DEQUEST 2044 | DEQUEST 2052 |
|---|---|---|---|---|---|
| Chemical Structure | $N(CH_2Y)_3$ [a] | $CH_3C(OH)Y_2$ [a] | | $(CH_2)_2$ <$N-(CH_2Y)_2(K)$ [a] / $N-(CH_2Y)_2(K)$ | $(CH_2)_6$ <$N-(CH_2Y)_2(NH_4)$ [a] / $N-(CH_2Y)_2(NH_4)$ |
| Related Products | 2005DN, 2006 | 2015DN, 2018 | | 2041, 2042 | 2054 |
| Acute Fish Toxicity | | | | | |
| Tested as | Neutral sol'n.[b] | Neutral sol'n.[b] | Neutral sol'n.[c] | Neutral sol'n.[b] | Neutral sol'n.[b] |
| Duration | 4 days | 4 days | 48 hr. | 4 days | 4 days |
| Test Species | Bluegills/Rainbow Trout | Bluegill/Rainbow Trout | Mosquitofish/ Golden Shiners/ Green Sunfish | Bluegills/Rainbow Trout | Bluegills/Rainbow Trout |
| $TL_{50}$ (ppm) | >1000/>1000 | 500/360 | 780/1270/1400 | >1000/>1000 | > 1000/>1000 |
| Chronic Fish Toxicity | | | | | |
| Tested as | | Neutral sol'n.[c] | Neutral sol'n.[d] | | |
| Duration | | 5 months | 60 days | | |
| Test Species | | Guppy, Swordtail, Blue Moon Pleety | Green Sunfish/ Mosquitofish/Bluegills | | |
| Results | | 30 ppm "no effect" on survival rate | 60 ppm "no effect" on feeding, color, hatching, pathologic lesions. | | |

(a) Y represents the phosphonate group, $-\overset{O}{\overset{\|}{P}}(OM)_2$ where M equals hydrogen ion unless otherwise indicated.
(b) Performed by Industrial Bio-Test Laboratories, Inc., Northbrook, Illinois.
(c) Performed at Monsanto Research Laboratories.
(d) Performed at Mississippi State University.

III-21

NALCO CHEMICAL COMPANY

Product Environmental Information File

PRODUCT NO. 310 PRINCIPAL USE Cooling Water Treatment

PHYSICAL PROPERTIES: Max. recommended product dosage level 100 ppm

Physical Form ______ Color ______ Odor ______

Specific Gravity @ ______ °F = ______ Density ______

Viscosity @ ______ °F = ______ cp pH of 1% solution ______

Flash Point ______ °C or °F by ______ Method

Other ______

| Fish Toxicity: | Species | $TL_m$ | |
|---|---|---|---|
| | Guppies | ______ ppm | ______ hr |
| | Zebras | ______ ppm | ______ hr |
| | Trout | ______ ppm | ______ hr |
| | Bluegills | ______ ppm | ______ hr |

BOD (5 Day) ppm product used to determine BOD Neat 5 Day BOD 10,410 ppm

= BOD at use level 1.04 ppm. COD 231,000 (max use level 23.1 ppm)

Total heavy metal content by combined APDC extraction – emission spectrographic analysis = 1.21 ppm ($10^{-6}$) in product

Calculated total heavy metal content in treated water system

Max. recommended product dosage of 100 ppm ($10^{-6}$) X total heavy metals in product of 1.21 ppm ($10^{-6}$)

= als maximum calculated level of heavy metals in treated system of .000121 ppm

This product contains ______ (ppm) (%) heavy metals as an active ingredient which is not included in the following analysis:

EMISSION SPECTROGRAPHIC BREAKDOWN OF TOTAL HEAVY METAL CONTENT BY ELEMENT

| Element | ppm of element in product | Min. detectable limit of test (ppm) | Calculated maximum level of element in treated system (ppm) |
|---|---|---|---|
| ntimony | | < .02 | |
| rsenic | | < .05 | |
| ismuth | | < .01 | |
| admium | | < .01 | |
| hromium | | < .01 | |
| obalt | | < .01 | |
| opper | 0.04 | < .01 | .000004 |
| on | 0.2 | < .01 | .00002 |
| ead | | < .07 | |
| anganese | | < .01 | |
| ercury | | < .01 | |
| olybdenum | 0.5 | < .01 | .00005 |
| ickel | 0.07 | < .01 | .000007 |
| n | | < 10 | |
| [illegible] | | < .01 | |
| n | | < .01 | |
| ungsten | | < .05 | |
| anadium | | < .01 | |
| inc | 0.4 | < .03 | .00004 |

719 348

719 190

NALCO MEMO to: R. J. Christensen

FROM P. Song

DATE March 18, 1976

FILED TO J. A. Baumbach
G. T. Farley
D. T. Reed
J. E. Scott
J. E. Shannon
G. J. Zivtins
Lab Office Files

SUBJECT Bio-oxidation of Nalco 310 and Dequest 2000


ABSTRACT

An investigation to compare the biodegradability of Nalco 310 and Dequest 2000 was performed in laboratory Bio-oxidation Units. Under semi continuous conditions, 37% of Nalco 310 was oxidized as compared to 5% for Dequest 2000 after 24 hours. Under closed system conditions and using an acclimatized seed, 84% Nalco 310 was biodegraded as compared with 40% for Dequest 2000 after 14 days. Hydrolysis of both products was insignificant after 7 days in Chicago tap.




acclimated seed was 37% and 5% respectively. Once again the orthophosphate levels in both units remained low. Figure 4 shows the Monsanto semi-continuous study of Dequest 2000.

3. Closed System Operation - The units were operated as a closed system for 14 days except for the addition of synthetic media at day 6. During this period the percent reduction of Nalco 310 was 84% as compared with 40% for Dequest 2000. Comparison of this data may be made with the "River Die Away" study (Figure 5) by Monsanto in which settled Meramec River water was used.

During the operation of the units as closed systems, the orthophosphate levels were seen to rise as the synthetic media was exhausted. This phenomena was first observed between day 2 and day 6 of operation. As shown in Table I the orthophosphate level rose from 0.9 to 5.5 ppm in the Nalco 310 unit and from 0.2 to 1.1 ppm in the Dequest 2000 unit.

The major part of the orthophosphate must originate from the biodegradation of the organophosphate provided by the Nalco 310 and Dequest 2000. A minor part comes from the subsequent death of the microbial cells after the dextrose (carbon) and urea (nitrogen) is exhausted. As long as the dextrose and urea are provided to yield an F/M ratio (food to mass) of 2.5 or greater, the bacterial growth rate is logarithmic and the organophosphate is rapidly used (as a growth factor). However, as the F/M ratio decreases the cells enter the endogenous growth phase and grow on stored energy reserves. When this supply is exhausted, catabolism occurs. The dead cells yield adenosine triphosphate and phospholipids to the environment which the surviving cells catabolize. One of the by-products of this catabolism is orthophosphate.

After 6 days when the synthetic media containing dextrose and urea was again added, the orthophosphate levels in both units were observed to drop and again rise as these nutrients were exhausted.

B. Hydrolysis in Chicago Tap

1. Nalco 310 - As shown in Table II a loss of 7.3 ppm or 14% product occurred after 7 days. It is felt that most of this was due to hydrolysis since

Attachment 2

BFS

DES Table 8.10 Corrected for BFS 700 MW and Inter-system Sales
and
Revised to Delete 240 MW Capacity Planne  982

| | | PSO Forecast | Purchases | Responsibility | Gen Additions | Ca_ _ lity | Sales | Total Capability | Reserve Margin | Percent Reserve |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1975 | 2071 | | | | 2422 | | | | |
| | 1976 | 2390 | 458 | 1932 | | 2992 | 709 | 2283 | 351 | 18.2 |
| | 1977 | 2521 | 310 | 2211 | + 3 | 2955 | 396 | 2599 | 308 | 17.5 |
| | 1978 | 2719 | 310 | 2409 | | 2995 | 171 | 2824 | 415 | 17.2 |
| | 1979 | 2931 | 310 | 2621 | +450 | 3445 | 336 | 3109 | 488 | 18.6 |
| | 1980 | 3158 | 310 | 2848 | +450 | 3895 | 536 | 3359 | 511 | 17.9 |
| | 1981 | 3401 | 310 | 3091 | | 3895 | 236 | 3659 | 568 | 18.4 |
| | 1982 | 3661 | 310 | 3351 | | 3895 | 236 | 3659 | 308 | 9.2 |
| | 1983 | 3940 | 310 | 3630 | -78 +700 | 4517 | 236 | 4281 | 651 | 17.9 |
| | 1984 | 4237 | 310 | 3727 | | 4517 | 236 | 4281 | 354 | 9.0 |
| | 1985 | 4550 | 310 | 4240 | +700 | 5217 | 236 | 4981 | 741 | 17.5 |
| | 1986 | 4882 | 310 | 4572 | | 5217 | 236 | 4981 | 409 | 8.9 |
| | 1987 | 5248 | 310 | 4938 | +450 | 5667 | 236 | 5431 | 493 | 10.0 |
| Staff's Upper Forecast | 1975 | | | | | | | | | |
| | 1976 | 2204 | 458 | 1746 | | 2992 | 709 | 2283 | 537 | 30.8 |
| | 1977 | 2345 | 310 | 2035 | + 3 | 2995 | 396 | 2599 | 564 | 27.7 |
| | 1978 | 2495 | 310 | 2185 | | 2995 | 171 | 2824 | 639 | 29.2 |
| | 1979 | 2654 | 310 | 2344 | +450 | 3445 | 336 | 3109 | 765 | 32.6 |
| | 1980 | 2824 | 310 | 2514 | +450 | 3895 | 536 | 3359 | 845 | 33.6 |
| | 1981 | 3001 | 310 | 2691 | | 3895 | 236 | 3659 | 968 | 36.0 |
| | 1982 | 3193 | 310 | 2883 | | 3895 | 236 | 3659 | 776 | 26.9 |
| | 1983 | 3397 | 310 | 3087 | -78 +700 | 4517 | 236 | 4281 | 1194 | 38.7 |
| | 1984 | 3615 | 310 | 3305 | | 4517 | 236 | 4281 | 976 | 29.5 |
| | 1985 | 3846 | 310 | 3536 | +700 | 5217 | 236 | 4981 | 1445 | 40.9 |
| | 1986 | 4092 | 310 | 3782 | | 5217 | 236 | 4981 | 1199 | 31.7 |
| | 1987 | 4354 | 310 | 4044 | +450 | 5667 | 236 | 5431 | 1387 | 34.3 |



Chicago tap is chlorinated and contains very few bacteria. However, after 33 days a significant reduction of 68% occurred which appears to be due to a combination of hydrolysis and bio-degradation.

2. Dequest 2000 - No loss of Dequest 2000 was detected after 7 days or after 33 days.

V. CONCLUSIONS

A. Bio-oxidation Units

1. 24 Hour Semi-Continuous Operation - Biodegradation of 50 ppm Nalco 310 was 37% as compared to 5% for 15 ppm Dequest 2000 (Figure 2).

2. Closed System Operation - Reduction of 50 ppm Nalco 310 was 84% after 14 days as compared to 40% for 15 ppm Dequest 2000. This test is comparable to the Monsanto River die-away test (artificially illuminated) in which approximately 32% Dequest 2000 was reduced (Figure 5).

3. Increases of orthophosphate levels occurred in both Bio-oxidation Units whenever the synthetic media was withdrawn.

a. Nalco 310 - Levels of orthophosphate varied from 1 ppm to 7.8 ppm (Figure 3).

b. Dequest 2000 - Levels of orthophosphate var ed from 0 to 3.6 ppm.

B. Hydrolysis in Chicago Tap

1. Nalco 310 - 15% of 50 ppm hydrolyzed after 7 days.

2. Dequest 2000 - 5% of 15 ppm hydrolyzed after 7 days.

Peter Song

P. Song

PS/gf
3/18/76

Att.

719 350

PUBLIC SERVICE COMPANY OF OKLAHOMA

BTU REQUIREMENT FORECAST
MILLION BTU

| YEAR | DEMAND FOR GAS & OIL | EXISTING GAS | DEFICIT GAS & OIL | COAL | NUCLEAR | TOTAL |
|---|---|---|---|---|---|---|
| 1976 | 147,515,159 | --- | --- | --- | --- | 147,515,1[illegible] |
| 1977 | 153,304,960 | 101,900,000 | 51,404,960 | --- | --- | 153,304,9[illegible]0 |
| 1978 | 146,947,660 | 84,600,000 | 62,347,660 | --- | --- | 146,947,660 |
| 1979 | 127,512,660 | 70,600,000 | 56,912,660 | 28,609,300 | --- | 156,121,960 |
| 1980 | 106,[illegible]74,260 | 58,200,000 | 48,074,260 | 65,749,000 | --- | 172,023,260 |
| 1981 | 109,685,660 | 47,900,000 | 61,785,660 | 66,650,600 | --- | 176,336,260 |
| 1982 | 103,240,860 | 39,900,000 | 63,340,860 | 71,238,800 | --- | 174,479,660 |
| 1983 | 76,800,760 | 33,300,000 | 43,500,760 | 69,693,600 | 43,376,800 | 189,871,160 |
| 1984 | 84,095,460 | 28,200,000 | 55,895,460 | 82,819,800 | 47,480,400 | 203,174,660 |
| 1985 | 58,645,240 | 23,800,000 | 34,845,240 | 74,449,[illegible]00 | 96,695,100 | 226,579,140 |
| DELAYING BFS #1 TO 1985 | | | | | | |
| 1983 | 120,177,560 | 33,300,000 | 86,877,560 | 69,693,600 | --- | 189,871,160 |
| 1984 | 131,575,860 | 28,200,000 | 103,375,860 | 71,238,800 | --- | 203,174,660 |
| 1985 | 111,963,540 | 23,800,000 | 88,163,540 | 71,238,800 | 43,376,800 | 226,579,140 |

Attachment 3

The following table and figure are submitted to assist in analysis of the need for nuclear fueled generation based on fuel requirements. Exhibited are the projected fuel requirements for PSO that show the declining use of natural gas from contracted reserves, the shortfall of petroleum fuel that will have to be obtained until the coal fired units are completed, and the energy use planned for BFS when operating in 1983. Delay of BFS to 1985 as suggested by the staff would mean that the energy supplied by BFS Unit 1 would have to be replaced by oil fuel burned in existing units designed for gas firing.

Should the FEA's energy projection prove to be correct, the total fuel we depicted in these exhibits will be reduced but the reduction should be made in gas and oil rather than delay of the nuclear energy source.



719 193

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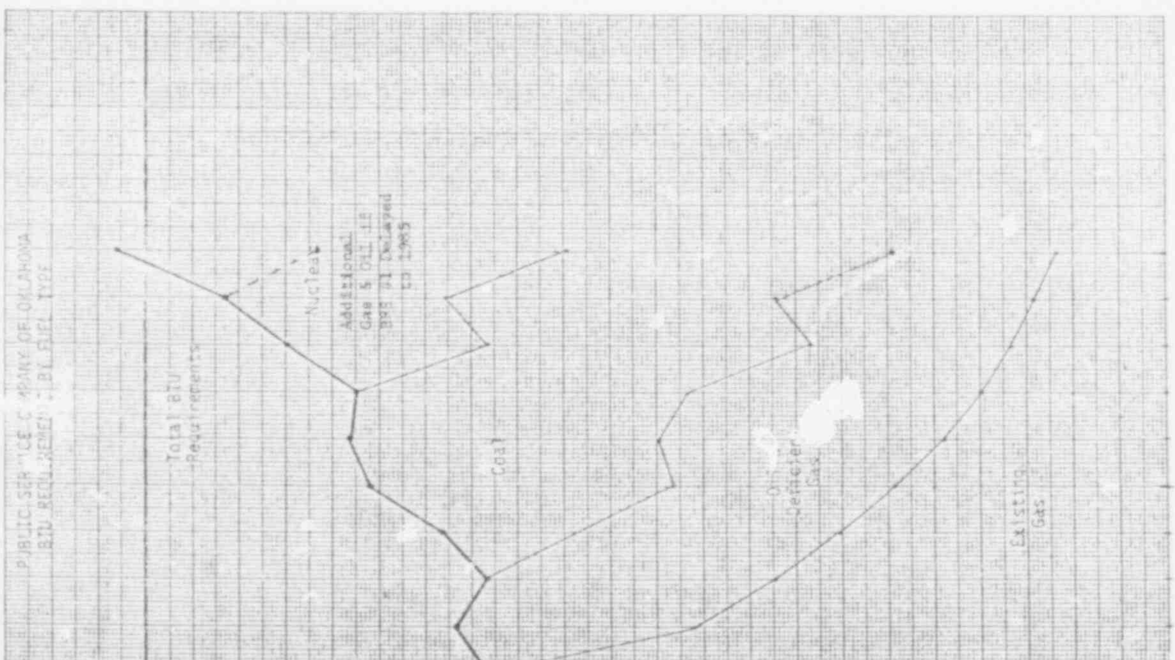
# POOR ORIGINAL

ATTACHMENT 4


A-92




719 352

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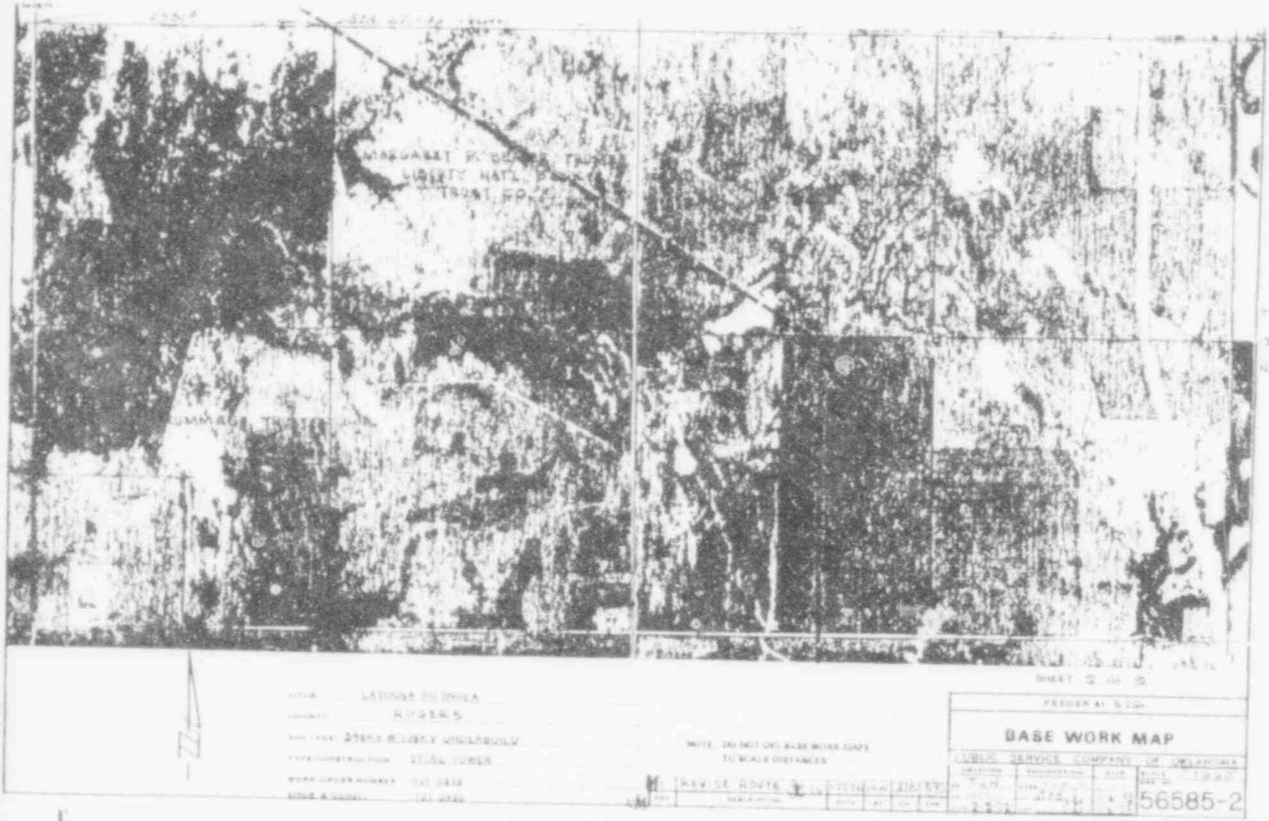


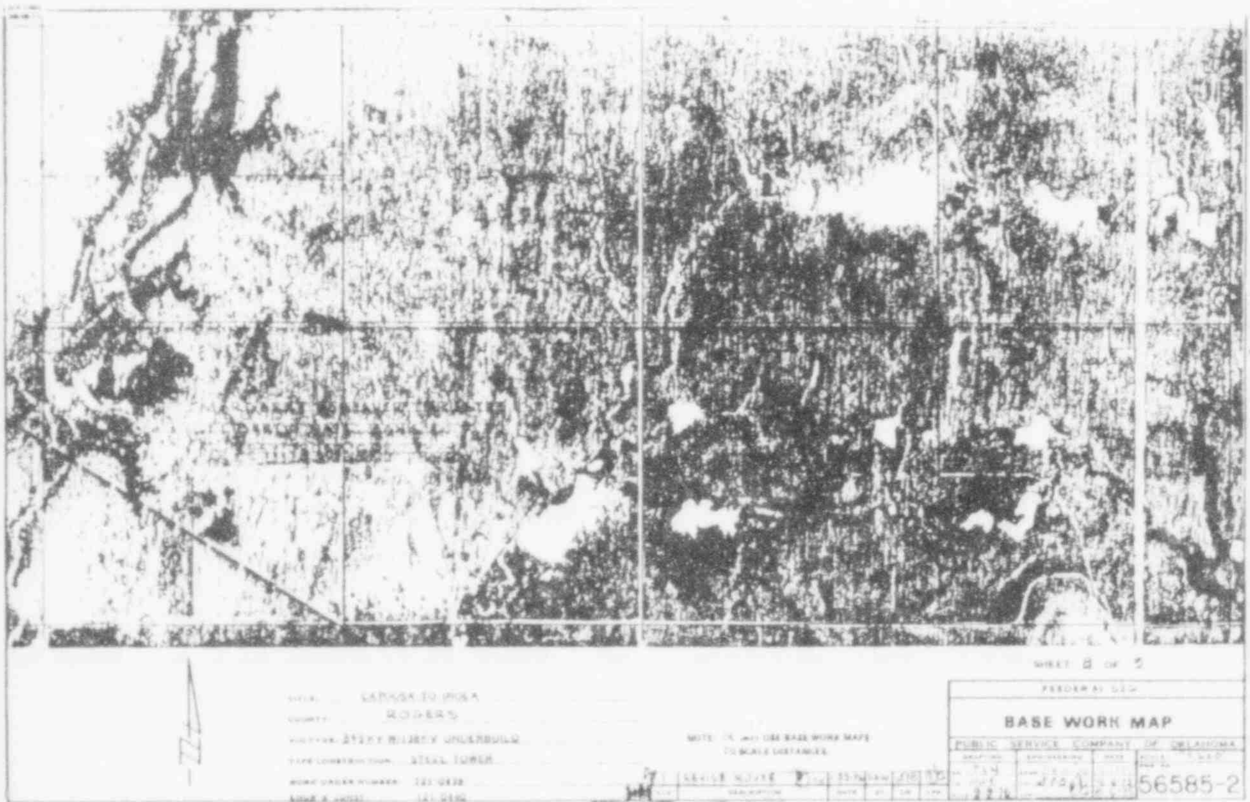






719 353

719 195

DEPARTMENT OF HEALTH, EDUCATION, AND WELFARE
OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20201

SEP 7 1976

STN-50-556
557

RECEIVED 9-10-76 U.S. NUCLEAR REGULATORY COMMISSION

Mr. William H. Regan, Jr., Chief
Environmental Projects Branch 3
Division of Site Safety and
Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

This Department has reviewed the draft environmental impact statement concerning the Black Fox Station, Units 1 and 2. The Department supports the position of the NRC Staff that in view of the impacts that might occur in the neighboring communities because of the construction of this facility, it would be desirable for the applicant to establish a set of socio-economic impact mitigation programs in coordination with local governments and planning agencies. These programs would address such topics as the influx of workers, housing, education and transportation.

In addition, prior to this plant becoming operational in the early 1980s it would be appropriate for interested Federal agencies and the State to assure that the surrounding communities and community hospitals are adequately prepared to respond in the event of an incident at the reactor which could result in the injury and/or radiation exposure of workers. Of particular importance will be the adequacy of emergency medical services at that time.

Thank you for the opportunity to review the document.

Sincerely,

Charles Custard

Charles Custard
Director
Office of Environmental Affairs

9184

UNITED STATES
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
WASHINGTON, D.C. 20545

SEP 1 0 1976

STN-50-556
557

9/7/76

Mr. William H. Regan, Jr.
Chief, Environmental
Projects Branch 3
Division of Site Safety and
Environmental Analysis
Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

This is in response to your transmittal dated July 15, 1976, inviting the U.S. Energy Research and Development Administration (ERDA) to review and comment on the Nuclear Regulatory Commission's draft environmental statement related to the construction of Black Fox Nuclear Generating Station Units 1 and 2.

We have reviewed the draft statement and have determined that the proposed action will not conflict with current or known future ERDA programs. However, enclosed are ERDA staff comments which you may wish to consider in the preparation of the final statement.

Thank you for the opportunity to review this statement.

Sincerely,

W. H. Pennington, Director
Office of NEPA Coordination

Enclosure:
ERDA Staff Comments

cc w/enclosure:
CEQ (5)

9433

719 354

719 196

ERDA STAFF COMMENTS
ON THE
NUCLEAR REGULATORY COMMISSION'S DES
RELATED TO THE CONSTRUCTION OF
BLACK FOX NUCLEAR GENERATING STATION UNITS 1 AND 2

1. Table of Contents - 9.3.8, Gaseous Radioactive Waste System

   There is no subsection 9.3.8 in the text.

2. Section 5.4

   We suggest that population dose commitments be discussed for carbon-14, krypton-85, and tritium, either during their atmospheric life, the ocean life of carbon-14 and tritium, or the ocean sediment life of arbon-14.

3. Table 6.2

   We suggest that there be some indication as to whether or not specific carbon-14 monitoring is planned.

719 355

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ENVIRONMENTAL IMPACT STATEMENT

S+N-50-556
557

U. Moore

This is a challenge, N.R.C. members! Are you ready for it? We challenge you to listen, and then to hear; to look and then really to see; to read and then to truly comprehend the TRUTH. We ask again, "Are you ready for this job?"

All the logical, truthful, unselfish statements made now and in the future concerning the real environmental impact of the proposed Black Fox Stations will be to no avail, will be as a beautiful flower, wilted in the sun before anyone beholds its gentle loveliness, if you N.R.C. people do not, will not, or cannot rise to this challenge. But, we believe you can.

We, the challengers, deplore even the thought of a radioactive-waste-producing entity in our midst. We already have with us more than enough radio-activity as a result of nuclear-bomb-testing fall-out, plus the nuclear plants now operating, in addition to natural radio-activity. We ask you to open your eyes and see the morally offensive attitude that approves of using up the good (electricity) now and leaving the evil (radio-active waste plusadecommissioned plant-scar on the landscape) for generations to come to deal with (not by their choice but out of necessity).

We believe, also that you should consider motive in assessing the various environmental impact statements made. The leaders of the opposition to nuclear facilities are truly great souls in their communities who are not only not being paid for their efforts but, quite to the contrary, are spending great chunks of time and energy, plus their own money, in an unselfish crusade to preserve and improve upon the present environmental conditions. How many of you of the N.R.C. and the utilities are doing this?

9416

They are urging, first of all, <u>conservation</u>, in all kinds of ways, of present energy sources. Secondly, alternative sources of energy, such as solar, wind, urban ore, and coal are being encouraged in every way possible, in the on-going adventure of making our state, our nation, our world, a better place to live.

The challenge again: "Seek ye the TRUTH, and the TRUTH will make you free." Will you?

Mrs. Joyce Hilgert
1317 South Guthrie
Tulsa, OK 74119

719 356

719 198

UNITED STATES DEPARTMENT OF COMMERCE
The Assistant Secretary for Science and Technology
Washington, D.C. 20230

September 17, 1976

S+N-50-556
557

Mr. Jan Norris
Environmental Project Manager
Nuclear Regulatory Commission
5650 Nicholson Lane
Rockville, Maryland 20850

Dear Mr. Norris:

The Draft Environmental Impact Statement for the "Black Fox Nuclear Generating Station Units 1 and 2," which accompanied your letter of July 15, 1976, has been reviewed in the Department of Commerce. We have no comment to offer in this instance.

Sincerely,

Sidney R. Galler

Sidney R. Galler
Deputy Assistant Secretary
for Environmental Affairs



9617

719 357

S+N-50-556
557

3115 Harvey Parkway
Oklahoma City, Okla. 73118
September 7, 1976

Director, Divis on of Site Safety and Environmental Analysis
Office of Nuclea Reactor Regulation
U.S. Nuclear Regu...ry Commission
Washington, D.C. 20555

Re: Black Fox Nuclear Generating Plants
of Public Service of Oklahoma

Dear Sir:

The Draft Environmental Statement of the above was just handed to me. Three of us wanted to see the report but your time limitation deters this.

I was trained at the University of Oklahoma School of Medicine in the field of Medical Photography. My first instruction was to protect myself and films from the X-Ray machine in the department 4 floors above me. I photographed all the birth defects that came to the attention of the University with a particular interest in persons affected by radiation. A very wise professor told me that 'any radiation is too much'. I was married to an OB-GYN doctor for 23 years and he died of cancer. He was distinguished in the field of infertility and used X-Rays only for the purpose of finding tube blockage that inhibited conception. Once con ception took place no X-rays were used excepting only those rare instances of the mother's life being endangered.

I have followed the defects of persons suffering radiation damage and know it is a horrible existance and death. The more that is learned about radiation the more it is realized that it is a two edged sword. We have no hospitals equipped to take care of radiation casualties. Only several hospitals in the country can treat those contaminated with plutonium.

The D.E.S. being discussed does not have adequate evacuation plans. Last year before the Kerr-McGee plant was closed I discussed evacuation plans with the Oklahoma Civil Defense Director. He did not even know where the K/M plant was located let alone an evacuation plan. If industry and the government cannot control a small plant like K/M, what makes you think that a better job will be done with two big nuclear plants? I don't think it will be controlled. You leave too much to the industry to police itself - sending the fox to the chicken house to protect the chickens. At least the proposed plants are aptly named Black Fox.

-2-

I met with Mr. Jan Norris in Tulsa some time ago and was told information would be sent as to how to intervene. I was assured of this. It was not sent. I am not an intervenors for that reason. It was too late when I found out. Just as it is too late for the people of Tulsa to rise up in arms over the proposed plants. The D.E.S. says that the plants will be 23 miles from downtown Tulsa-that is absurd. Anyway 23,000 miles would be too close.

I understand that rural coops in Missouri and southwest Oklahoma are funding Black Fox. Isn't this creating a monopoly? The rest of Oklahoma has to take the risks so other people can overuse electricity. This brings me to the main objection to the D.E.S.- conservation is not mentioned and in fact was considered a dirty word during the discussions I have heard from P.S.O. and N.R.C. people. Oklahoma has the potential to be a leader in uses of solar and wind power. The resea ch has been done all it needs is using.

Although we have the many days of sunshine and wind we also have many tornados and earthquakes. If you think you know someone who can predict those things are what will happen in them then you have fools for advisors. I find it very distressing that some of your advisors namely Ras ssen were being paid by the industry while conducting so called safety reports.

Enclosed is a report on the case for conservation. Please consider this before allowing any more nuclear plants.

Sincerely,
Roberta Ann Funnell
Roberta Ann Funnell

NOTE: The enclosure to Ms. Funnell's letter was a copyrighted publication, "Energy: The Case for Conservation" by Denis Hayes, published in Worldwatch Paper 4, January 1976, by the Worldwatch Institute. The document is available for reference in the NRC Public Document Room at 1717 H Street, N.W., Washington, D. C., and at the Tulsa City-County Library, Tulsa, Oklahoma.

POOR ORIGINAL

9618



719 199

Oklahoma

State Department of Health

Commissioner R. LEROY CARPENTER, M.D., M.P.H.

Northeast 10th Street & Stonewall
Post Office Box 53551
Oklahoma City, Oklahoma 73105

September 8, 1976

S+N-50-556
557



Director
Division of Site Safety and
Environmental Analysis
Office of Nuclear Reactor Regulations
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Sir:

We are pleased to offer the following comments on the Draft Environmental Statement related to construction of Black Fox Nuclear Generating Station, Units 1 and 2, Docket Nos. STN 50-556 and STN 50-557.

1. The number and location of off site sampling and radiation measurement sites are not adequate. In particular, sites to the south and east should be added. We agree with the philosophy of sampling at the location of the highest $\chi/Q$, but all directions from the plant site should also be covered.

2. The frequence of sampling for soil is not adequate. Once every three years allows too much time between samples. The sampling frequency should be at least once each year, with quarterly sampling much to be preferred.

3. The systems to be used in monitoring the liquid and gaseous effluents should be described in sufficient detail to allow an evaluation of their adequacy.

4. There is a discrepancy in the dose assessment, given in man-rem/yr., for the general population within the 50 mile radius of Black Fox Station (Section 5.4). Please clarify the differences in figures and further explain the methodology used.

September 8, 1976
Page 2

I hope that these comments will be useful to you in preparation of the Final Environmental Impact Statement for this installation.

Very truly yours,

R. LeRoy Carpenter

R. LeRoy Carpenter, M.D., M.P.H.
Commissioner of Health

POOR ORIGINAL

719 358

719 200

STN-50-556
557

ENVIRONMENTAL PROTECTION AGENCY
REGION VI
First International Building
1201 Elm Street
Dallas, Texas 75270

OFFICE OF THE REGIONAL ADMINISTRATOR

September 20, 1976

Mr. William H. Regan, Jr.
Chief, Environmental Projects Branch 3
Division of Site Safety and
Environmental Analysis
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555



Dear Mr. Regan:

The Environmental Protection Agency has reviewed the U. S. Nuclear Regulatory Commission's Draft Environmental Impact Statement issued July 15, 1976, in conjunction with the application of the Public Service Company of Oklahoma for permits to construct Black Fox Nuclear Generating Station, Units 1 and 2.

Certain materials added for corrosion inhibition, including zinc, chromium and phosphorus, will be discharged at levels in excess of new source standards. This matter should be resolved prior to publication of a final EIS. Also while we concur with the proposed location, design and operation of the cooling water intake structure, we request information concerning the scope of a monitoring program related to the intake structure. Details of these comments, as well as others, are attached as an enclosure to this letter. Comments on Fuel Cycle and Long-Term Dose Assessments, and High-Level Waste Management will be forthcoming under separate cover.

In accordance with our procedures we have classified the project LO (Lack of Objections) and have rated the draft statement Category 1 (Adequate). If you or your staff have any questions concerning our classification or comments, we will be glad to discuss them with you.

Sincerely yours,

John C. White
Regional Administrator

Enclosure

POOR ORIGINAL

9735

## ENVIRONMENTAL IMPACT OF THE ACTION

LO - Lack of Objections

EPA has no objections to the proposed action as described in the draft impact statement; or suggests only minor changes in the proposed action.

ER - Environmental Reservations

EPA has reservations concerning the environmental effects of certain aspects of the proposed action. EPA believes that further study of suggested alternatives or modifications is required and has asked the originating Federal agency to re-assess these aspects.

EU - Environmentally Unsatisfactory

EPA believes that the proposed action is unsatisfactory because of its potentially harmful effect on the environment. Furthermore, the Agency believes that the potential safeguards which might be utilized may not adequately protect the environment from hazards arising from this action. The Agency recommends that alternatives to the action be analyzed further (including the possibility of no action at all).

## ADEQUACY OF THE IMPACT STATEMENT

Category 1 - Adequate

The draft impact statement adequately sets forth the environmental impact of the proposed project or action as well as alternatives reasonably available to the project or action.

Category 2 - Insufficient Information

EPA believes the draft impact statement does not contain sufficient information to assess fully the environmental impact of the proposed project or action. However, from the information submitted, the Agency is able to make a preliminary determination of the impact on the environment. EPA has requested that the originator provide the information that was not included in the draft statement.

Category 3 - Inadequate

EPA believes that the draft impact statement does not adequately assess the environmental impact of the proposed project or action, or that the statement inadequately analyzes reasonably available alternatives. The Agency has requested more information and analysis concerning the potential environmental hazards and has asked that substantial revision be made to the impact statement. If a draft statement is assigned a Category 3, no rating will be made of the project or action, since a basis does not generally exist on which to make such a determination.



719 359

719 201

EPA #D-NRC-G06002-OK

ENVIRONMENTAL PROTECTION AGENCY

REGION VI

DALLAS, TEXAS

SEPTEMBER 1976

ENVIRONMENTAL IMPACT STATEMENT COMMENTS

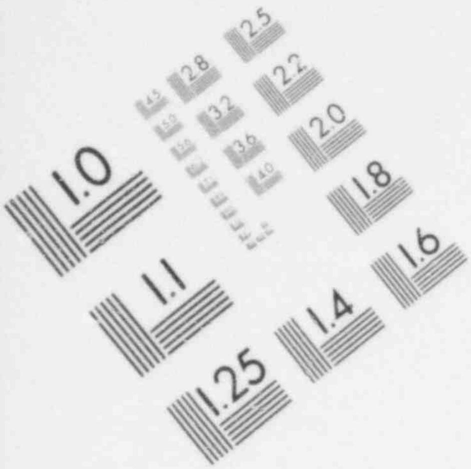
BLACK FOX NUCLEAR GENERATING STATION-UNITS 1 AND 2

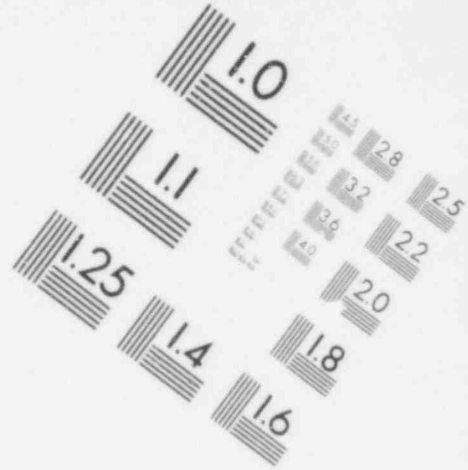
TABLE OF CONTENTS



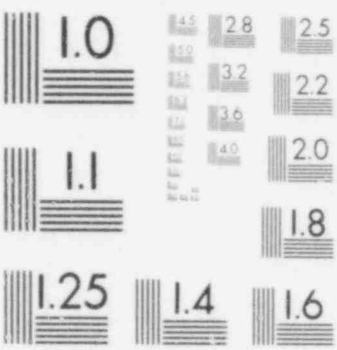
719 360

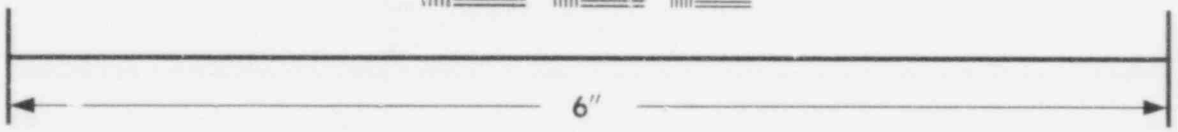
~~719 202~~

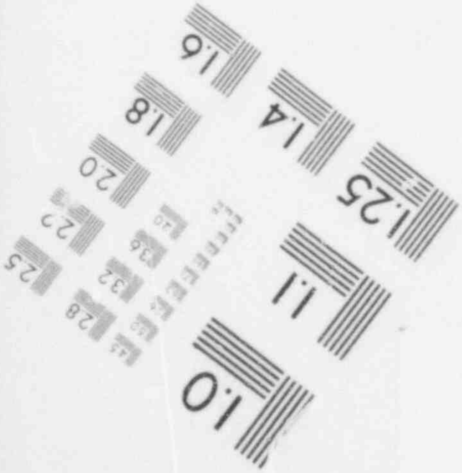




# IMAG_ EVALUATION TEST TARGET (MT-3)



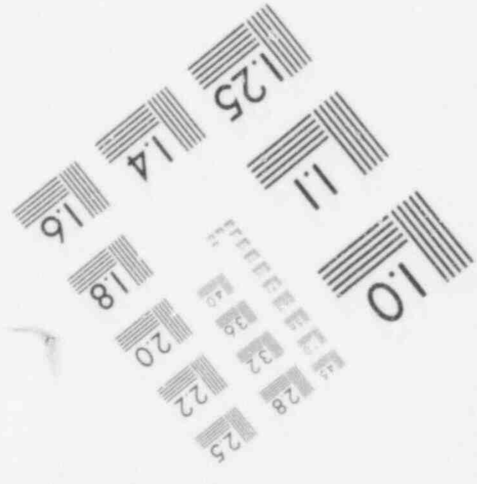
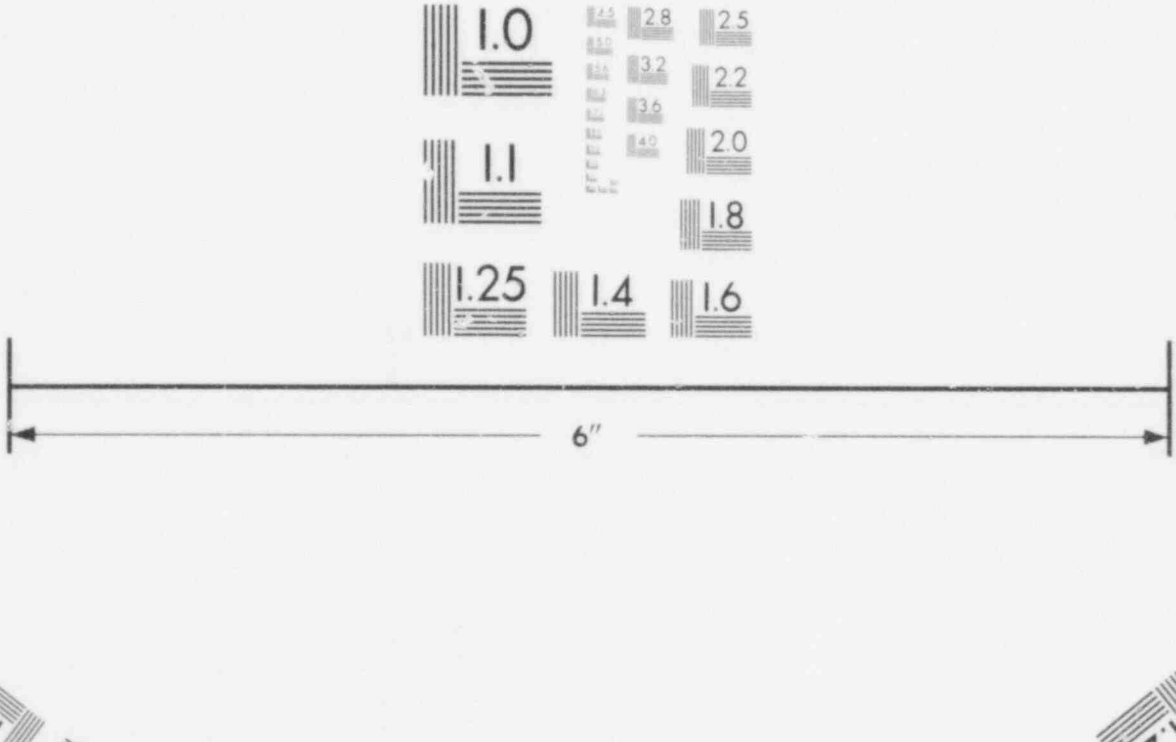
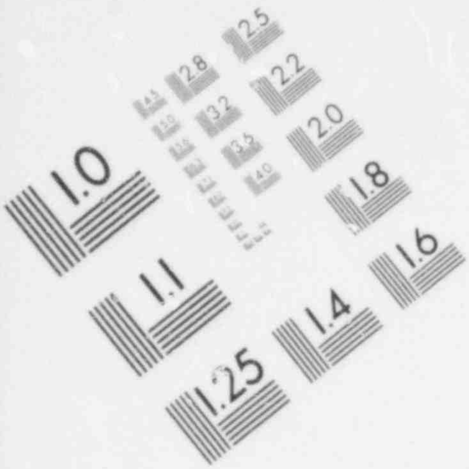
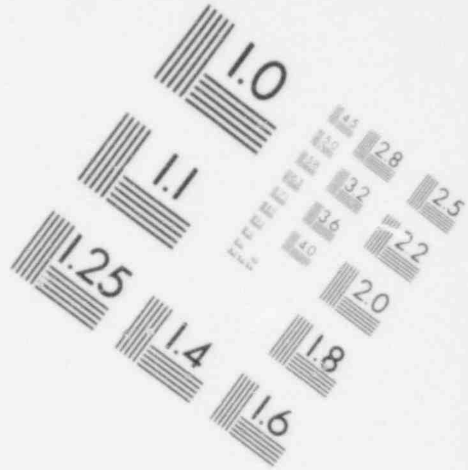


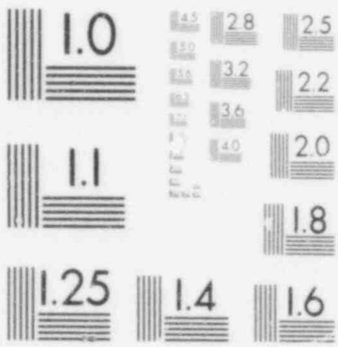
**IMAGE EVALUATION
TEST TARGET (MT-3)**

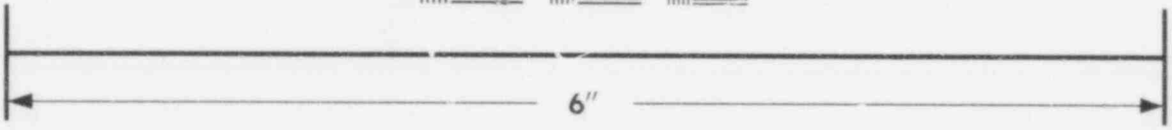


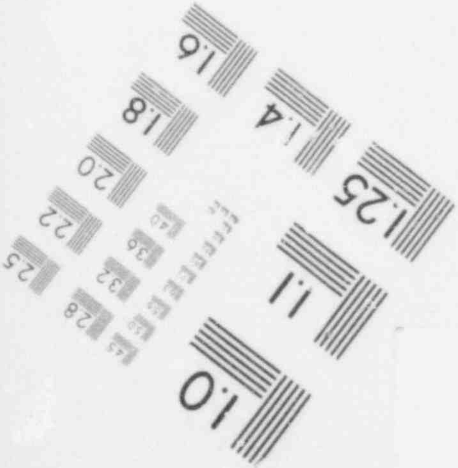


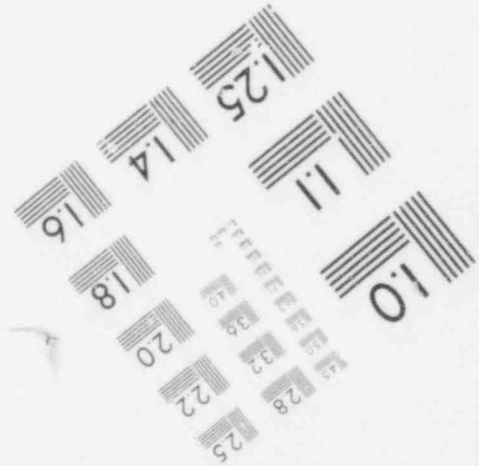


# IMAGE EVALUATION TEST TARGET (MT-3)





INTRODUCTION AND CONCLUSIONS

The Environmental Protection Agency has reviewed the U. S. Nuclear Regulatory Commission's Draft Environmental Impact Statement issued July 15, 1976, in conjunction with the application of the Public Service Company of Oklahoma for permits to construct Black Fox Nuclear Generating Station, Units 1 and 2. The proposed plant will be located on the Verdigris River in Rogers County, Oklahoma, approximately 12 miles east of the Tulsa city limits. The proposed generating station will produce up to 3,579 megawatts thermal per unit and will dissipate waste heat using circular mechanical - draft cooling towers. The Verdigris River will be the sole source of cooling water. The following are our major conclusions:

1. NRC's analysis of the radioactivity source terms and the resultant doses to humans are generally consistent with current practice. The dose calculated to the maximum individual through the milk ingestion pathway is acceptable assuming the present nearest location of milk cows is 2.3 miles north of the station and the station's operating parameters are as anticipated.

2. Tables 5.14 and 5.15 of the draft EIS indicate that certain materials added for corrosion inhibition, including zinc, chromium and phosphorus, will be present at levels in excess of new source standards In order to conform with standards of performance for new sources, the levels of these materials must be reduced.

3. The cooling water intake structure as proposed reflects best technology for this site; however, we would appreciate information concerning the scope of a monitoring program related to the intake structure since a similar program may be made part of the NPDES permit.

RADIOLOGICAL ASPECTS

Radioactive Waste Treatment

The Black Fox Station uses clean steam to reduce the radioactivity source term at the turbine gland seals, but apparently does not utilize clean steam to seal critical turbine valves against steam leakage, and does not incorporate treatment of ventilation exhaust from potentially contaminated equipment areas of the turbine building. Consequently, the turbine ventilation effluent accounts for almost 70 percent of the gaseous radioiodine released from the station. As discussed in the following section, "Dose Assessment," radioiodine effluents projected for the Black Fox Station are near the design objective values of 10 CFR Part 50, Appendix I; thus, unanticipated off-normal operations could result in exceeding the values, and this could require interruption in plant operation.



We believe the treatment options (to reduce the turbine building ventilation system iodine source term) should be re-examined by the applicant from a cost-effectiveness perspective in consideration of the possibility that station operation might have to be interrupted due to Appendix I violations.

Dose Assessment

The applicant has collected on-site meteorological data since November 1973 (page 2-28). Meteorological observations have also been made at the Tulsa airport which, according to the draft statement, ". . .provide the foundation for describing the local meteorological conditions that are applicable to the site . . ." (page 2-25). This leaves open to question which data were used to develop the site dispersion parameters used to calculate the radiological impacts. Section 6.1.4 strongly implies that the on-site meteorological data were used. However, a spot comparison with X/Q estimates reported by the applicant in the Environmental Report indicates X/Q values approximately a factor of three larger than the long-term-average values used in the draft statement. We request that the final statement clarify the basis for the dispersion parameters used in the dose calculations.

Although cattle are apparently allowed to graze on the reactor site itself (page 2-32) the statement identifies the nearest milk-producing animal as being 2.3 miles north of the station. As shown in Table 5.6 and 5.11, radioiodine releases, mainly from the turbine building ventilation exhaust, lead to a calculated potential annual dose commitment to an infant through the milk ingestion pathway of 15 mrem/yr. This dose rate corresponds to the design objective limit proposed by the U.S. AEC in its "Concluding Statement of Position of the Regulatory Staff," Docket No. RM-50-2, although it is lower than the value in NRC's 10 CFR Part 50, Appendix I, and also that of EPA's proposed uranium fuel cycle standards. The calculation is thought to be conservative but is based on known uncertainties and is also subject to unknown errors. Therefore, it is possible that plant operation may have to be interrupted due to unanticipated events or off-normal plant operation; for example, fuel failure rates or equipment leakage may be higher than anticipated, or changes may occur in land use patterns in the site environs. Also, refinements in the dose models could lead to higher dose estimations. These considerations led to our suggestion (in the previous section, "Radioactive Waste Treatment") that turbine building ventilation treatment options be re-examined.

EPA's Drinking Water Regulations for Radionuclides were promulgated in final form on July 9, 1976 (Federal Register 28402) and are scheduled to be in effect on June 24, 1977, well in advance of Black Fox Station operation. The final environmental statement should include reference to these regulations in context with the drinking water radiation dose commitment projections reported in Section 5.4.

We are encouraged that the NRC is now calculating annual population dose commitments to the U. S. population which is a partial evaluation of the total potential environmental dose commitments (EDC) of H-3, Kr-85, C-14, iodines and "particulates." This is a big step toward evaluating the EDC, which we have urged for several years. However, it should be recognized that several of these radionuclides (particularly C-14 and Kr-85) will contribute to long-term population dose impacts on a world-wide basis, rather than just in the U. S. To the extent that the draft statement: 1) has limited the EDC to the annual discharge of these radionuclides, 2) is based on the assumption of a population of constant size, and 3) assesses the doses delivered during 50 years only following each release, it does not fully provide the total environmental impact. Assessment of the total impact would: 1) incorporate the projected releases over the lifetime of the facility (rather than just the annual release, 2) extend to several half-lives or 100 years, beyond the period of release, 3) consider, at least qualitatively or generically, the world-wide impacts. Thus, we suggest that future assessments recognize these influences on the total environmental impact or specify the limitations of the model used.

Direct Radiation

EPA recognizes the difficulties associated with trying to predict, in advance of station operation or even construction, what the off-site direct radiation doses will be from nitrogen-16. Accurate dose estimates will probably not be available until results from the post-operational radiation monitoring program have been completed. It should be noted, however, that, based on the dose estimations reported in the draft statement, the direct dose to an individual residing near the site boundary could exceed EPA's proposed standard for the uranium fuel cycle (Federal Register 23420, May 29, 1975). The applicant should be advised that, in event post-operational experience indicates actual off-site dose rates in excess of 25 mrem/yr will be produced at close-in locations where persons reside, corrective action such as additional shielding or operational limitations may be required in the future. The final statement should address direct radiation dose in the context of EPA's proposed uranium fuel cycle standards. We believe that direct radiation doses to humans in the site environs can be controlled by proper plant design and layout. Thus, we urge the applicant to consider carefully the design options to minimize the effects of this dose exposure pathway.

Reactor Accidents

The EPA has examined the NRC's analyses of accidents and their potential risks. The analyses were developed by NRC in the course of its engineeering evaluation of reactor safety in the design of nuclear plants. Since these issues are common to all nuclear plants of a given



type, EPA concurs with NRC's generic approach to accident evaluation. The NRC is expected to continue the efforts initiated by AEC to insure safety through plant design and accident analyses in the licensing process on a case-by-case basis.

In 1972, the AEC initiated an effort to examine reactor safety and the resultant environmental consequences and risks on a more quantitative basis. The EPA continues to support this effort. On August 20, 1974, the AEC issued for public comment the draft Reactor Safety Study (WASH-1400), which was the product of an extensive effort to quantify the risks associated with light-water-cooled nuclear power plants. The EPA's review of this document included in-house and contractual efforts and culminated in the release of final Agency comments on the draft report on August 15, 1975. Initial comments were issued on November 27, 1974.

EPA completed its review of the final Reactor Safety Study on June 11, 1976, and issued a public report of its findings. In general, our previous conclusions on WASH-1400 are still valid. We identified apparent errors, omissions and questionable assumptions regarding health effects analyses, emergency remedial measures and failure analysis which would generally increase the calculated probabilities or consequences and thus, the risks. We are working with NRC to resolve these points so that a consensus may be attained regarding the validity of the risk estimates given in WASH-1400. A generic analysis of the acceptability of the present risks or whether increased levels of safety are necessary has not yet been made. In the meantime, we have identified no reason serious enough to call for an immediate restriction in the application of nuclear power.

Fuel Cycle and Long-Term Dose Assessments (Comments Forthcoming)

High-Level Waste Management (Comments Forthcoming)

Transportation

In its earlier reviews of the environmental impacts of transportation of radioactive material, EPA agreed with AEC that many aspects of this program could best be treated on a generic basis. The NRC has codified this generic approach (40 Federal Register 1005) by adding a table to its regulations (10 CFR Part 51) which summarizes the environmental impacts resulting from the transportation of radioactive materials to and from light-water reactors. This regulation permits the use of the impact values listed in the table in lieu of assessing the transportation impact for individual reactor licensing actions if certain conditions are met. Since the Black Fox Station appears to meet these conditions and since EPA agrees that the transportation impact values in the table are reasonable, the generic approach appears adequate for this plant.

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The impact value for routine transportation of radioactive materials has been set at a level which covers 90 percent of the reactors currently operating or under construction. The basis for the impact or risk of transportation accidents is not as clearly defined. At present EPA, ERDA, and NRC are each attempting to more fully assess the radiological impact of transportation risks. The EPA will make known its views on any environmentally unacceptable conditions related to transportation. On the basis of present information, EPA believes that there is no undue risk of transportation accidents associated with the Black Fox Station.

NON-RADIOLOGICAL ASPECTS

General

The Black Fox Nuclear Generating Station will employ two boiling water reactors each of which is designed to produce up to 3,579 megawatts thermal (MWt). Dissipation of waste heat will be accomplished by circular mechanical-draft cooling towers, three per reactor unit. Cooling water for the BFS heat dissipation system will be drawn from the Verdigris River.

FWPCA Requirements

As presently proposed, condenser cooling at Black Fox Nuclear Generating Station, Units 1 and 2 will be achieved by the use of circular mechanical-draft cooling tower. Under normal plant operating conditions, water will be withdrawn from the Verdigris River at the maximum rate of 62 cfs. Discharge will be accomplished by means of surface discharge channel after retention in a wastewater holding pond for a minimum time of 1 day.

EPA will be responsible for issuance of a discharge permit for Black Fox Nuclear Generating Stations, Units 1 and 2 under the National Pollutant Discharge Elimination System (NPDES) - Section 402 of the Federal Water Pollution Control Act Amendments of 1972 (FWPCA). Black Fox was determined to be a new source pursuant to Section 306 of PL 92-500; therefore, the discharge permit must meet standards of performance for new sources as defined in "Steam Electric Power Generating Point Source Category Effluent Guidelines and Standards, Federal Register of October 8, 1974. These guidelines call for closed-cycle cooling and the circular mechanical-draft cooling tower proposed for Black Fox is in general conformance with these standards. These new source standards also call for no detectable level on materials added for corrosion inhibition, including but not limited to zinc, chromium, and phosphorus. Tables 5.14 and 5.15 of the draft EIS indicate these materials will be present at levels in excess of detectable limits. These materials must be reduced to conform with standards of performance



for new sources. State Certification will be requested by EPA prior to the issuance of a NPDES permit for Black Fox. We have received a NPDES permit application for Black Fox from the Public Service Company of Oklahoma.

Water Intake Structure

Section 316(b) of the FWPCA requires that ". . . the location, design, construction, and capacity of cooling water intake structure reflect the best technology available to minimize adverse environmental impact."

The intake structure as proposed appears to conform with these requirements; however, we would appreciate being advised concerning the scope of a monitoring program related to the intake structure. A similar program may be made part of the NPDES permit.

Additional Comment

Of all the water uses of the Verdigris River to the confluence of the Arkansas River, nearly three-fourths is used by the City of Broken Arrow for industrial and municipal purposes and is taken from only 3 miles downstream of the Black Fox discharge. We are interested in the potential doses through the drinking water pathway from Accident Class 3.3 which involves release of the liquid waste storage tank contents. This accident is listed in Table 7.2 of the draft statement, but the doses estimated to result from this accident are only those from the release of volatiles through the atmospheric pathway. Doses through the liquid pathway are not evaluated because it is assumed that the release would be detected and remedial action taken in time to limit exposures through this pathway. In view of the industrial and municipal use of the water a short distance downstream, we believe the final statement should address the specific case of inadvertent or accidental release of liquid radwaste and the resultant doses through the liquid pathway. The final statement should also discuss the dose-mitigating actions which can be undertaken by the applicant following such a liquid release including plans, if any, to coordinate such actions with the City of Broken Arrow.

POOR ORIGINAL

## ENVIRONMENTAL IMPACT OF THE ACTION

LO - Lack of Objections

EPA has no objections to the proposed action as described in the draft impact statement; or suggests only minor changes in the proposed action.

ER - Environmental Reservations

EPA has reservations concerning the environmental effects of certain aspects of the proposed action. EPA believes that further study of suggested alternatives or modifications is required and has asked the originating Federal agency to re-assess these aspects.

EU - Environmentally Unsatisfactory

EPA believes that the proposed action is unsatisfactory because of its potentially harmful effect on the environment. Furthermore, the Agency believes that the potential safeguards which might be utilized may not adequately protect the environment from hazards arising from this action. The Agency recommends that alternatives to the action be analyzed further (including the possibility of no action at all).

## ADEQUACY OF THE IMPACT STATEMENT

Category 1 - Adequate

The draft impact statement adequately sets forth the environmental impact of the proposed project or action as well as alternatives reasonably available to the project or action.

Category 2 - Insufficient Information

EPA believes the draft impact statement does not contain sufficient information to assess fully the environmental impact of the proposed project or action. However, from the information submitted, the Agency is able to make a preliminary determination of the impact on the environment. EPA has requested that the originator provide the information that was not included in the draft statement.

Category 3 - Inadequate

EPA believes that the draft impact statement does not adequately assess the environmental impact of the proposed project or action, or that the statement inadequately analyzes reasonably available alternatives. The Agency has requested more information and analysis concerning the potential environmental hazards and has asked that substantial revision be made to the impact statement. If a draft statement is assigned a Category 3, no rating will be made of the project or action, since a basis does not generally exist on which to make such a determination.

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United States Department of the Interior

OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20240

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SEP 22 1976

SEP 27 1976

Dear Mr. Regan:

Thank you for your letter of July 15, 1976, transmitting copies of the Nuclear Regulatory Commission's draft environmental statement for Black Fox Nuclear Generating Station, Units 1 and 2, Rogers County, Oklahoma.

Our comments are presented according to the format of the statement -- by subject.

General

We have prev...sly commented on the applicant's environmental report (ER) but find that our suggestions or corrections have not generally been reflected in the draft statement. Many of our earlier comments, particularly with respect to fish and wildlife interests, are therefore reiterated in the comments that follow.

We believe the 2,206-acre BFS site and transmission corridors have considerable potential for fish and wildlife management. In view of the increasing stress being placed on our Nation's natural systems by such activities as industrial development, urban expansion, and increased agricultural production, the U.S. Fish and Wildlife Service hopes that the Public Service Company of Oklahoma will recognize the opportunity for wildlife enhancement at the BFS site. Therefore, we strongly recommend that the applicant develop a fish and wildlife management and public use plan for the BFS. The Fish and Wildlife Service will gladly work with the applicant in the development of such a plan.

Streamflow Characteristics

Clarification is needed as to the true flows to be anticipated in the Verdigris River at the plant intake and discharge area. The statement indicates on page 2-16 that since 1970 the streamflow on the Verdigris below Oologah Reservoir has been regulated within limits set by the Corps of Engineers to maintain the navigability of the system. ...sequently, on the same page, it is stated that

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the Corps of Engineers anticipates a regulated low flow of 379 cfs. In the same paragraph it is noted that the low flow on July 25, 1974, was 40 cfs, or less than the plant intake requirements. Since 379 cfs is being used for "worst case" conditions rather than 40 cfs, the relationship of these flows should be explained and put in proper perspective since, to the reader, they appear inconsistent.

There is no specific assessment of the impact that a consumptive water use of 39,000-acre feet per year by the power plant will have on the navigational requirements or other uses of the Verdigris particularly during periods of low flow. Also the final statement should note how the operation of the Oologah Reservoir will be modified to meet these additional demands. No mention is made of the institutional arrangements for obtaining the water from the Verdigris either with the Corps of Engineers or other water agency if involved. Much information is provided on the Verdigris River but the reader is left to draw his own conclusions as to the seriousness of the impacts resulting from the power plant withdrawals. Although it is not emphasized, it is evident that the power plant will draw from the navigation pool. Nevertheless it is important to know the flow in the river at the plant site.

Radioactive Wastes

The draft statement fails to provide a comprehensive picture of the disposal of radioactive wastes from the reactor. High-level wastes are omitted from discussion altogether and references to other than high-level solids are scattered and lack any discussion of environmental effects. On the other hand, radioactive wastes in operational liquid and gaseous effluents from the reactor are discussed in considerable detail; yet the radioactivity stated to be in the liquid and gaseous effluents represents but a minor fraction of the radioactive wastes created by the reactor.

On page 5-37, the environmental effects of the management of low- and high-level wastes are mentioned solely by reference to table 5.16 which was extracted from 10 CFR 51. However, there is no information on high-level wastes in table 5.16. The quantities of radionuclides, their hazards and the proposed methods of disposal should be given; and the environmental considerations involved should be discussed in detail.



Table 5.16 indicates that of the other than high-level wastes, 600 curies per year from uranium mills would be returned to the ground, and 1 curie per year from fuel conversion and fabrication would be buried. These figures fail to include either the 2,100 curies per year shipped from the reactor for burial, page 3-16, or the disposal of the reactor and associated contaminated components upon decommissioning, mentioned on page 10-3. The radioactive quantities involved in the latter items are not given, but again are likely to dwarf the quantities shown in table 5.16. The environmental considerations involved in their disposal should be discussed in detail in the final statement.

Mineral Resources

Although oil and gas production at the site is relatively small, we see no reason at present why production should not be allowed to continue. Other than concern for possible "leakage and attendant pollution problems" noted on page 5-1, the draft statement presents no reasons why continued operation is incompatible with the project. As best as we can determine, the coalbeds underlying the site are relatively thin, which together with thick overburden probably would preclude coal recovery regardless of whether or not the generating station was constructed.

Outdoor Recreation

As noted in the last paragraph on page 4-18 of the statement, we recommend the applicant establish a mitigation program in conjunction with local governments and planning agencies to address the impact that the large number of construction workers will have on recreation in the communities in the BFS area.

Historic and Archeological Sites

Prehistoric sites are discussed on page 2-43. Question 2.47 in Supplement I of the Environmental Report implies that 80 percent of the total station site has been subjected to an intensive archeological field survey. Should any construction or earth disturbance activities be necessary on the remaining 20 percent of the plant site, that area should also be surveyed and the results included in the final environmental statement.

T.e terrestial discussion in paragraph 7, page 4-21 should give further consideration to archeology to cover unfinished surveys. If the transmission line routing has been finalized and the archeological survey completed, the results should be included in the final statement. Substations along the route should also be surveyed and the results noted.

Specific Comments

Page i, paragraph 2.d. It is not clear if the 170 acres is part of the 460 acres or if it is partly from the 2,400 acres.

Page ii, paragraph 3.i. The term "sensible" air quality is not clear.

Page 2-3. Figure 2.2 should be updated in the final statement. A later figure is provided in ER Supplement 3 dated June 1976.

Page 2-32, 2.7.1.2: The statement to the effect that Oklahoma's greater prairie chicken is endangered is incorrect. For an updated reference see Federal Register, Vol. 40. No. 188, Friday, December 26, 1975.

Pa[illegible]: There seem to be considerable differences between t[illegible]cant's calculations and those of the NRC staff.

[illegible]ne first paragraph, the NRC staff calculated 800 Ci/reactor/[illegible]ar released in noble gases. The applicant calculated 390 Ci/reactor/year.

In the second paragraph, the NRC staff calculated 2700 Ci/reactor/year released with noble gases and .003 Ci released with I-131. The applicant calculated 500 and .32.

In the fifth paragraph, the NRC staff calculated radiation releases from the radwaste building ventilation air at 55 Ci/reactor/year in noble gases and .0[illegible] Ci/reactor/year in I-131. The applicant estimated 1500 and .022. The difference in the calculated figures range from 100% to 10,000 %. The reason for this variation in calculations and its significance should be addressed in this section.



Page 3-20, 3.6.1.4: It is stated that the wastewater pond will have a mean retention time of 24 hours. This conflicts with the statement on page 5-34, that the holding pond has a 24-hour minimum retention time. We do not understand how the mean retention time can be the same as the minimum. A more detailed explanation of the holding pond's retention capabilities should be presented in the final statement.

Page 3-28, 3.7.1: It is stated that although some new roads will have to be constructed, the applicant does not intend to maintain them. We believe this requires further explanation as to the anticipated effects of road construction in the area.

Page 4-1, 4.1: The construction of the discharge channel, the railroad spur, and access roads will also result in some disturbance. This should be identified and the acreages involved should be added to Table 4.1.

Page 4-5, 4.1.13: We suggest that the potential for impacts on ground water as a result of seepage from the wastewater pond should be evaluated, and natural or designed mitigating measures should be planned accordingly.

Page 4-6, 4.1.2.2: The reported width of the discharge channel should be changed from "70-inch" to "70 feet."

Page 4-10, 4.3.2.2: Several times in this section, as well as in other parts of the statement, it is indicated that the staff "recommends" or "suggests" procedures which may not agree with the proposed procedures of the applicant. Unless covered in the staff specific requirements in Section 4.5.2.2, these differences appear to remain unresolved. The final statement should indicate the NRC procedure for implementation of these recommendations or resolving differences with the applicant.

Page 4-12, 4.4.1: This section should be revised in accordance with the information contained in ER Supplement 3 which indicates a revised location for the railroad spur and adjacent access road.

Page 4-14, 4.4.3: This relates to the map and discussion concerning northeast Oklahoma. To clarify the size of the area involved, the phrase "within the 100-square-mile region" should be revised to read "within an area of about 10,000 square miles."

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Page 4-19, Items 3 and 7: The term "gentle slopes" should be made more definite to assure that in grading, proper sloping is actually observed. Preferably the implementation of such measures should be detailed in NRC's permit specifications.

Page 5-9, 5.3.2.4: Unless a low river flow of 40 cfs was utilized, we question the staff conclusion that, except when ambient river temperatures exceed 90 degrees F., the proposed design of the surface discharge and its operation will be acceptable in meeting water quality standards relating to temperature. The values used by the NRC staff to arrive at this conclusion should be provided in the final statement.

Page 5-27, 5.5.1.1: The draft statement recognizes that ". . . concentrations of sulfate discharged to the river after complete mixing will exceed State standards during times of minimum flow." It is further stated that Ba, Cd, F, and Hg will exceed State guidelines. Also, it is recognized that a discharge permit will be required for the operation of BFS and that chemicals which will exceed State standards and guidelines will be considered by the State prior to the issuance of the permit. We believe that the applicant should make every effort to assure that the plant will meet all applicable water quality standards and that these efforts should be discussed in the final environmental statement. The status of the application for a discharge permit should be noted.

Page 5-28, 5.6.1.2: The applicant concludes that ". . . there will be a beneficial commitment of the site . . . to more productive ecosystems than those associated with pre-existing site uses." To fully utilize this important fish and wildlife habitat, we have previously recommended that a fish and wildlife management and public use plan be implemented for the area. The plan should include preservation of natural areas, development of additional habitat for fish and wildlife, and provision of adequate facilities for public use including access for fishing and hunting and related recreational uses to assure maximum public benefit. This plan and proposed implementation schedule should be developed as a project feature and should be discussed in the final statement.

POOR ORIGINAL



Page 5-29, 5.6.1.2: The commitment of the site to a different ecosystem does not necessarily mean a more productive ecosystem. There should be a more thorough explanation of the meaning of the term "productive" as it is used in this discussion.

Page 5-32, 5.6.2.1: This section concludes that the loss of entrained plankton will not be detrimental to the Verdigris River ecosystem. Similar conclusions are also cited for losses of macroinvertebrates and ichthyoplankton. We question whether the information presented can fully support these conclusions. The projected worst-case loss of the ichthyoplankton should be detailed for the projected record drought during the life of the plant. If normal ichthyoplankton losses approach the 16.4% figure estimated for phytoplankton and zooplankton, a record drought could severely alter the fish production of the Verdigris.

The staff recognizes the uncertainty over the actual distribution patterns of aquatic organisms in the Verdigris, and states that the applicant intends to monitor entrainment losses. The Fish and Wildlife Service would appreciate receiving the results of this monitoring program. Also, we believe that the final environmental statement should describe what actions will be taken if monitoring indicates that entrainment losses are significant. The value of the post-operational monitoring assessment depends highly on establishment of an accurate preoperational baseline study.

Page 8-17, 8.3.1: This section indicates that PSO intends to add Northeastern plants 3 and 4 to its system, each of which is a 450 MW coal burning station. Because the power plants will be located in close proximity, the possibility of plant interaction and resulting environmental effects should be discussed in the final statement.

Page 9-3, 9.1.2.2, 3rd sentence: The assumption is made that the Black Fox station can be operated at a capacity factor of 70%. The basis for this assumption should be fully explained in the final statement.



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Page 9-12, 9.3.1.6: The cost of cooling ponds should be discussed since costs were considered for each of the other alternatives. With this information a better comparison of alternatives can be made. A one-year delay due to a choice to use cooling ponds should not eliminate such ponds from consideration since the discussion [illegible] page 8-17 indicates that time may be less critical than initially presumed.

Page 10-7[illegible], 10.[illegible]: It is stated "At t[illegible] onset of construction, any use of the [illegible] site for recreation (hunting, fishing) will cease for the life of the station." In view of our previous comment relative to development of a fish and wildlife management and public use plan, we recommend this statement be modified or deleted, as may be appropriate, in accordance with any plans being considered for public use.

We hope these commen s will be helpful to you.

Sincerely yours,

[signature]

Deputy Assistant Secretary of the Interior

Mr. William H. Regan, Jr.
Chief, Environmental Projects Branch 3
Division of Site Safety and Environmental Analysis
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

3900 Cashion Pl.
Oklahoma City, Okla. 73112
Sept 28. 1976



Jan Norris
Director Division of Site Safety and Environmental Analysis
Nuclear Reactor Regulation
N.R.C., Washington, D.C. 20555          S.T.N. 50-557 , 50-556

Dear Sir,

I am submitting this material to amplify my statements on lack of water availability for Black Fox 1 and 2. Not only the European countries but also this area of the country is suffering from extreme drought conditions. I believe tying up enormous quantities for Black Fox would be a real mistake. You certainly can't turn the water off that is used for a nuclear power station. These factors should be taken into consideration before the Final Environmental Impact Statement is issued on Black Fox 1 and 2.

Sincerely,
[signature]
Ilene Younghein

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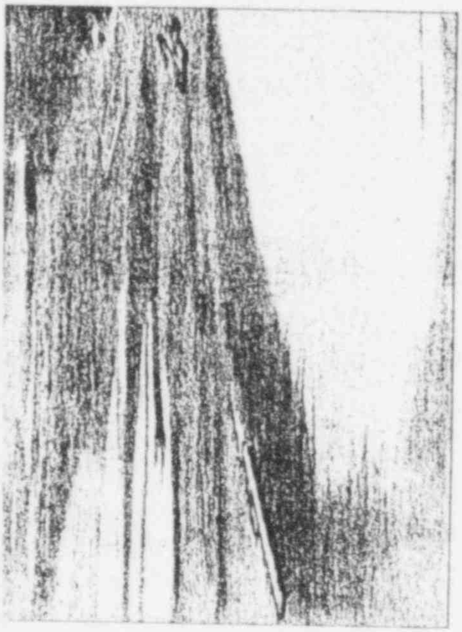
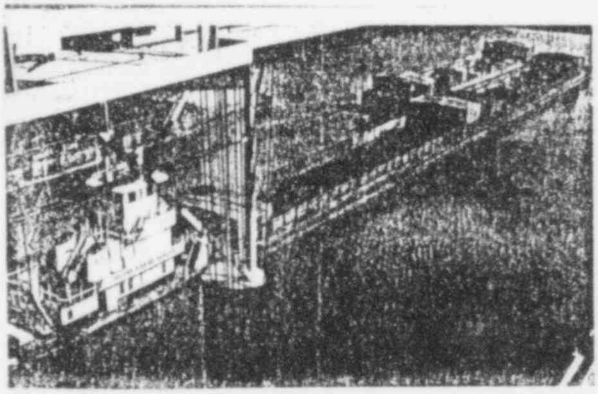


Sand bars and mud flats strangle Mississippi River traffic in an area 15 miles south of Memphis.

Low River Level Could Boost Food Prices

# He Don't Keep Rollin' Along

By David W. Hacker



Barges Up A Creek?

Several Oklahoma firms which use the Arkansas River Navigation System are worried that bottlenecks on the lower end of the system may tie up the transportation of their products.

# Low Water, Narrow Passages Are Bottlenecks For Barges

By Ted Coombes
Journal Business Editor

Low water and narrow passages on the lower end of the McClellan-Kerr Arkansas River Navigation System could "raise hell" with at least two Oklahoma grain elevators and possibly other state industries which use the system.

"In another 30 days we'll be in the middle of the soybean harvest and if (navigation problems) will raise hell with us," said Russ Milliken, manager of the Eastern Oklahoma Export Grain Elevator.

The company has barge loading facilities on the navigation channel near Wagoner and ships various grains down the waterway.

Problems have developed along the last 15 miles of the navigation system, where it connects with the White River and then flows into the Mississippi River, the Little Rock District of the Army Corps of Engineers confirmed Thursday.

Midwestern droughts have dropped the White and Mississippi to all-time lows for this time of year, said John Coleman, chief of the navigation section of the Little Rock district.

Depth of the channel, which was designed to accommodate barges drawing as much as nine feet of water, dropped to only eight feet along the White last week and is now only 8.5 feet deep, he said.

In addition, the channel has gotten extremely narrow in some locations, forcing shippers to break up eight-barge tows and bring them through the narrow passes only two at a time.

As a result, shipments along the waterway have slowed tremendously and barge capacities have had to be reduced so the barges can navigate the narrow, shallow passages. Shipping costs have consequently risen.

"Barge companies are reluctant to bring barges this far up the river and come out with a short load," Milliken said. "With the river the way it is, you're taking quite a bit of tonnage away from the revenues."

"It's going to affect us in an identical manner," said Rich Kloefeller, grain buyer and traffic manager for Oklahoma-Kansas Grain Corp., which ships wheat, milo and grain by-products from its elevator at the Port of Catoosa.

"The next two months are the most critical in trying to obtain barges," he said.

Kloefeller said his firm has had to reduce its barge capacity by 300 tons, or about 2,000 bushels. "That means there's going to have to be more barges during a time when barge numbers are more critical."

Milliken said he is currently loading barges to a depth of only 7.5 feet because of the shallow conditions.

Ed Dale, owner of Dale Petroleum Co., said his firm has been forced to add additional barges to move its 5,000 barrels [illegible]

[illegible] of reduced barge capacity.

While it used to take his barges eight days to make the journey down the channel, unload and return to Muskogee, tricky navigation through the narrow passages has pushed that "turn around" time to 12 or 13 days. Shipping costs have mounted accordingly, he said.

A restriction of shipping along the Arkansas River could spell trouble for the grain export market. One-fourth of all grain exported from the United States is transported down the Mississippi River, and a portion of that tonnage is moved down the McClellan-Kerr system.

In addition to grain and petroleum products, many other products are shipped to and from Oklahoma through the channel, including steel, coal, fertilizer and newsprint.

Milliken is worried that unless the navigation problems are corrected before the soybean harvest, he'll be stuck with a full elevator and no way to ship his grain.

"Anytime you have a harvest, barges are scarce. And unless you can utilize a barge to the fullest extent, you're just losing that much you should be able to ship out.

"The farmer looks for a normal routine to handle his crop when it's harvested," he said. "If I fill up and can't ship, then it's a problem."

"Storage is at a premium right now all over the country," Kloefeller added. "If the situation doesn't turn around, it's going to put everybody in a financial bind."

POOR ORIGINAL

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DEPARTMENT OF THE ARMY
TULSA DISTRICT, CORPS OF ENGINEERS
POST OFFICE BOX 61
TULSA, OKLAHOMA 74102

SWTOD-N

1 November 1976

Mr. Jan A. Norris, Project Manager
Environmental Projects Branch
Nuclear Regulatory Commission
5650 Nicholson Lane
Rockville, Maryland 20850

Dear Mr. Norris:

Inclosed is a final copy of the Tulsa District Corps of Engineers' comments on the Nuclear Regulatory Commission draft EIS for the Black Fox Nuclear Generating Station Units 1 and 2.

Sincerely yours,

JAMES P. JONES
Chief, Operations Division

1 Incl
As stated

TULSA DISTRICT CORPS OF ENGINEERS' COMMENTS
ON DRAFT ENVIRONMENTAL STATEMENT
FOR THE BLACK FOX NUCLEAR GENERATING
STATION UNITS 1 AND 2

1. Page 2-11, Section 2.3.4.

However, penstocks have been constructed in the Oologah Dam for future power generation when the need arises.

Actually, an extra conduit was constructed in the dam and power was only a partial consideration for this being done. Power as a purpose for the Oologah project was deauthorized by Section 97 of the Water Resources Development Act, Public Law 93-251 dated 7 March 1974.

2. Page 2-16, 2.5.1.1 Verdigris River, 3rd Paragraph.

This volume is consistent with Corps of Engineers calculations of water requirements for navigation during a "once-in-50-years" drought and cannot be guaranteed for a more severe drought.

This sentence implies that Corps of Engineers guarantees the yield up to a 50-year drought. We wish to clarify that the Corps of Engineers contracts for the conservation storage, but cannot guarantee yields. The yield rates are estimates which depend on many factors such as climatological conditions, the manner in which the storage is utilized, the extent of diversions from stream above the project and demands below the project.

3. Page 2-16, 2.5.1.1 Verdigris River, 4th Paragraph.

The 30-day average extreme low flow past the site and Newt Graham Lock and Dam, as estimated by the Corps of Engineers for years subsequent to 1980, when the navigation system is utilized to capacity, is 379 c.f.s.

The above statement was apparently made based on information contained in a 1968 study "Water Requirements for Navigation on Verdigris River at Lock and Dam No. 18." This was an in-house study rather than an official report. The study showed that if the system reached capacity a minimum flow of 379 c.f.s. would be required, however, it was not intended to predict that this would be the condition in 1980. In fact, releases to maintain the required pool at Newt Graham Lock and Dam have been as low as 40 c.f.s. and during periods such as when repairs are made on upstream projects, could be lower. Releases from upstream projects will be determined by demands for the water in accordance with actual demands such as navigation traffic, water supply contracts and water rights. There is no requirement to maintain a minimum flow past Newt Graham Lock and Dam other than for valid water rights.

4. Page 2-16, 2.5.1.1 Verdigris River, 4th Paragraph.

Presently, the maximum probable flood flow predicted in the site vicinity by the Corps of Engineers is 555,200 c.f.s. (565.5 feet m.s.l.).

The Corps of Engineers did not compute the probable maximum flood at the site or the elevation.

5. Page 5 1, 5.2 Water Use.

This consumptive use is above 15% of the expected regulated low flow (379 c.f.s.) and 3% of the average flow (2,000 c.f.s.) in this stretch of the river.

As discussed in comment 3, 379 c.f.s. is not the expected value for low flow. Also on page 2-16 the median flow is quoted as being 2,000 c.f.s. rather than average, which appears to be about 3 times higher than long term flow would indicate.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
FIRST INTERNATIONAL BUILDING
1201 ELM STREET
DALLAS, TEXAS 75270

October 14, 1976

STN-50-556
557



Mr. William H. Regan, Jr.
Chief, Environmental Projects Branch 3
Division of Site Safety and Environmental Analysis
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Regan:

Our letter dated September 20, 1976, concerning our review of the U. S. Nuclear Regulatory Commission's Draft Environmental Impact Statement issued July 15, 1976, in conjunction with the application of the Public Service Company of Oklahoma for permits to construct Black Fox Nuclear Generating Station, Units 1 and 2 stated that additional comments would be forthcoming. Accordingly, we are submitting our comments ... Fuel Cycle and Long-Term Dose Assessments and High-Level Waste Management.

Should you or your staff have any questions concerning these comments, we will be glad to discuss them with you.

Sincerely yours,

John C. White
Regional Administrator

Enclosures

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Fuel Cycle and Long-Term Dose Assessments

The Environmental Protection Agency (EPA) is ... ible for establishing generally applicable environmental radia...on protection standards to limit unnecessary radiation exposures and radioactive materials in the general environment resulting from normal operations of facilities that are part of the uranium fuel cycle. EPA has concluded that environmental radiation standards for nuclear power industry operations should take into account the total radiation dose to populations, the maximum individual dose, the risk of health effects attributable to these doses (including the future risks arising from the release of long-lived radionuclides to the environment), and the effectiveness and costs of effluent control technology. EPA has propc...' standards which are expressed in terms of individual dose limits to members of the general public and limits on quantities of certain long-lived radioactive materials in the general environment.

A document entitled "Environmental Survey of the Uranium Fuel Cycle" (WASH-1248) was issued by Atomic Energy Commission (AEC) in conjunction with a regulation (10 CFR 50, Appendix D; now 10 CFR 51) for application in completing the cost-benefit analysis for individual light-water reactor environmental reviews (39 Federal Register 14188). This document has been used by the Nuclear Regulatory Commission (NRC) in draft environmental statements t... assess the incremental environmental impacts attributed to fuel cycle c...mponents which support nuclear power plants. As suggested in our comments on the proposed rulemaking (January 19, 1973), if this approach were to be used for future plants, it would be important for NRC to periodically review and update the information and assessment techniques used. We believe that the following points should be considered in any such update efforts:

- The commitment of land and resources for ultimate waste disposal;
- The economic and resource commitments to future generations, including societal and institutional commitments; and
- The economic, resource, and energy costs of ultimate waste disposal ... balanced against the short-term benefits realized by energy production.

In response to a recent court decision, the NRC has prepared a report (to be publicly released in October 1976) concerning the ultimate disposal of nuclear wastes. We understand that the NRC will initiate an interim rulemaking and then will schedule hearings in early 1977 to obtain public input to modify their generic fuel cycle impact analyses (which are included in individual nuclear power plant impact statements). We recommend that the general points we have itemized above be considered in the rulemaking hearings.

High-Level Waste Management

The techniques and procedures used to manage hig...-lev... ...dioactive wastes will have an impact on the environment. To a ... tain extent, these impacts can be directly related to individual projects because the reprocessing of spent fuel from each new facility will contribute to the total waste. As part of NRC's generic approach to waste management impacts, the AEC, on September 10, 1974, issued for comment a draft statement entitled, "The Management of Commercial High-Level and Transuranium-Contaminated Radioactive ...aste" (WASH-1539). In this regard, EPA provided extensive comments on WASH-1539 on November 21, 1974. Our major criticism was that the draft statement lacked a program for arriving at a satisfactory method of "ultimate" high-level waste disposal. At present, the Energy Research and Development Administration (ERDA) intends to prepare a ...ew draft statement which will discuss waste management and emphasize ult...te disposal in a more comprehensive manner. EPA concurs with this decision an... will review and comment on the new draft statement when it is available.

Because of a recent court decision regarding the issue of ultimate disposal of radioactive wastes, the NRC has concluded that no new full-power operating license, construction permit, or limited work authorization should be issued pending resolution of the issue. The NRC is preparing a revised environmental survey on the probable contribution to the environmental costs of licensing a nuclear power reactor that is attributable to the reprocessing and waste management stages of the uranium fuel cycle.

EPA is cooperating with both NRC and ERDA to develop an environmentally acceptable program for radioactive waste management. In this regard, EPA will establish environmental radiation protection criteria for radioactive waste management in 1977 and environmental radiation protection standards for high-level waste in 1978. We have concluded that the continued development of the Nation's nuclear power industry is acceptable from an environmental standpoint during the period required to satisfactorily resolve the waste management question.

APPENDIX B. LETTER FROM OKLAHOMA STATE HISTORIC PRESERVATION OFFICER

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# OKLAHOMA HISTORICAL SOCIETY

FOUNDED MAY 27, 1893

HISTORICAL BUILD' ‹G
OKLAHOMA CITY, OKLAHOMA 73105



RECEIVED
Proj. Mgr. [signature]
Action Party________

May 7, 1975

Mr. B.H. Morphis
Director, Nuclear Division
Public Service Company of Oklahoma
Black Fox Station
Box 201
Tulsa, Oklahoma 74102

Dear Mr. Morphis:

After having consulted with you concerning the Black Fox Station and the areas of Archeological and Historic significance, we appreciate receiving your assurance that the sites in question are well out of the project area and therefore, will not be affected.

Thank you for giving us the opportunity to review this project.

Cordially,

George H. Shirk by SHH

George H. Shirk
State Historic Preservation Officer

## APPENDIX C. NEPA POPULATION DOSE ASSESSMENT

Population dose commitments are calculated for all individuals living within 50 miles of the facility employing the same models used for individual doses (see Regulatory Guide 1.109). In addition, population doses associated with the export of food crops produced within the 50-mile region and the atmospheric and hydrospheric transport of the more mobile effluent species, such as noble gases, tritium, and carbon-14, have been considered.

### Noble Gas Effluents

For locations within 50 miles of the reactor facility, exposures to these effluents are calculated using the atmospheric dispersion models in Regulatory Guide 1.111 and the dose models described in Section 5.1 and Regulatory Guide 1.109. Beyond 50 miles, and until the effluent reaches the northeastern corner of the United States, it is assumed that all the noble gases are dispersed uniformly in the lowest 1000 meters of the atmosphere. Decay in transit was also considered. Beyond this point, noble gases having a half-life greater than one year (e.g., Kr-85) were assumed to completely mix in the troposphere of the world with no removal mechanisms operating. Transfer of tropospheric air between the northern and southern hemispheres, although inhibited by wind patterns in the equatorial region, is considered to yield a hemisphere average tropospheric residence time of about two years with respect to hemispheric mixing. Since this time constant is quite short with respect to the expected mid-point of plant life (15 years), mixing in both hemispheres can be assumed for evaluations over the life of the nuclear facility. This additional population dose commitment to the U. S. population was also evaluated.

### Iodines and Particulates Released to the Atmosphere

Effluent nuclides in this category deposit onto the ground as the effluent moves downwind, which continuously reduces the concentration remaining in the plume. Within 50 miles of the facility, the deposition model in Regulatory Guide 1.111 was used in conjunction with the dose models in Regulatory Guide 1.109. Site-specific data concerning production, transport and consumption of foods within 50 miles of the reactors were used. Beyond 50 miles, the deposition model was extended until no effluent remained in the plume. Excess food not consumed within the 50-mile distance was accounted for, and additional food production and consumption representative of the eastern half of the country were assumed. Doses obtained in this manner were then assumed to be received by the number of individuals living within the direction sector and distance described above. The population density in the sector is taken to be representative of the eastern United States, which is about 160 people per square mile.

### Carbon-14 and Tritium Released to the Atmosphere

Carbon-14 and tritium were assumed to disperse without deposition in the same manner as krypton-85 over land. However, they do interact with the oceans. This causes the carbon-14 to be removed with an atmospheric residence time of four to six years with the oceans being the major sink. From this, the equilibrium ratio of the carbon-14 to natural carbon in the atmosphere was determined. This same ratio was then assumed to exist in man so that the dose received by the entire population of the U. S. could be estimated. Tritium was assumed to mix uniformly in the world's hydrosphere, which was assumed to include all the water in the atmosphere and in the upper 70 meters of the oceans. With this model, the equilibrium ratio of tritium to hydrogen in the environment can be calculated. The same ratio was assumed to exist in man, and was used to calculate the population dose, in the same manner as with carbon-14.

### Liquid Effluents

Concentrations of effluents in the receiving water within 50 miles of the facility were calculated in the same manner as described above for the Appendix I calculations. No depletion of the nuclides present in the receiving water by deposition on the bottom of the Verdigris River was assumed. It was also assumed that aquatic biota concentrate radioactivity in the same manner as was assumed for the Appendix I evaluation. However, food consumption values appropriate for the average individual, rather than the maximum, were used. It was assumed that all the sport and commercial fin and shellfish caught within the 50-mile area were eaten by the U. S. population.

Beyond 50 miles, it was assumed that all the liquid effluent nuclides except tritium have deposited on the sediments so they make no further contribution to population exposures. The tritium was assumed to mix uniformly in the world's hydrosphere and to result in an exposure to the U. S. population in the same manner as discussed for tritium in gaseous effluents.

## APPENDIX D. DETAILED ANALYSIS OF IMPINGEMENT POTENTIALS

Since the numbers of fish are low in the main channel where the BFS intake is to be located, impingement should result in minimal losses that should have no damaging impact on fish populations. As shown in ER, Table 2.2-109, almost six times as many fish were captured in the backwater areas as in the main channel of the Verdigris River, indicating that the fish populations, to a large extent, are being maintained in the backwater areas. The proportion of the fish that would come in contact with the intake structure would be small compared with the total number of the fish in the main channel and even smaller compared with the number inhabiting the main channel and backwater areas of the river at any one time. Additionally, the mid-depth location of the intake should have a beneficial effect in protecting fish from impingement. Because the majority of important fish species (based on relative abundance and "endangered" status) prefer backwater areas or, if found in the main channel, inhabit the surface or bottom portions of the channel (Table D.1), a rather small percentage will be found in the middle third of the water column in the vicinity of the intake at any one time. ER Table 2.2-110 shows that only seven important species (longnose gar, gizzard shad, carp, flathead catfish, largemouth bass, white crappie, and freshwater drum) would feed 25-33% of the time in the middle third of the water column. Capture data (ER, Table 2.2-109) and general observations on habitat preferences (Table D.1) indicate that only three--longnose gar, freshwater drum, and possibly the flathead catfish--would be fairly abundant in the main channel.

The mobility of those fish that will venture into the immediate vicinity of the intake screens will, in great part, determine whether or not they will become impinged. In addition to species differences, the mobility of fish is significantly affected by size and by such environmental factors as water temperature and dissolved oxygen concentration.[1] Based on an intake velocity of 0.5 ft/sec and on assumptions concerning swimming speeds of fish (ER, p. 5.1-10) and concerning the proportion of fish within various size classes (ER, Table 2.2-110), the applicant concludes that 40% to 90% of the fish that come into the immediate vicinity of the intake will be impinged. To obtain an estimate of maximum impingement possibilities, the applicant incorporated conservative estimates of the swimming speed of fish, ignoring sustained speed (speed that can be maintained over several minutes) or darting speed (speed that can be obtained by a single effort).[1] Sonnichsen et al.,[1] summarizing work by others, state that sustained speed is greater than cruising speed by a factor of two and darting speed is greater by a factor of six. Use of darting or sustained speeds would obviously increase a fish's chances of avoiding impingement and would tend to decrease the minimum size of a fish capable of avoiding impingement.

Table D.2, which summarizes the results of some studies into the sustained and burst speeds of fish, shows that fish are capable of swimming at speeds greater than the conservative estimate given by the applicant (two body lengths per second). Based on the applicant's estimates, fish less than 105 mm (4.13 inches) long would be subject to impingement during normal plant operation. Results from Table D.2, however, indicate that even fish as small as 1.25 inches are capable of maintaining speeds greater than the 0.5 ft/sec required to avoid impingement. The values given in Table D.2 are for sustained speeds over three or more minutes; even faster bursts of speed could be expected for shorter periods. It has been shown that the river herring can maintain speeds of about 15 or 16 body lengths per second for several seconds.[2] This implies that even a fish as small as 0.04 inch would be capable of outmaneuvering the normal intake velocity of 0.5 ft/sec. Kerr[3] found that striped bass and chinook salmon could sense a screen obstruction several inches away, and in attempting to swim away from it, would, for brief periods, reach speeds up to two times faster than those demonstrated for ten-minute endurance curves.

Several factors can influence the speed that fish are capable of achieving. For example, it has been shown that fed fish are capable of sustaining greater speeds than starved fish.[4] Ambient water temperature[5,6] and general physical condition of the fish,[3,5,7] among other factors, also affect swimming performance.

Except for fish in poor physical condition and very small fish with little or no ability for self-propulsion, the majority of the fish that come into the immediate vicinity of the intake should be able to avoid impingement. Of the fish that cannot escape intake velocities, those smaller than 3/8 of an inch will be entrained (unless impinged upon debris), and the remainder will be impinged. Those impinged for more than ten minutes will probably die from suffocation by pressure or from physical damage and shock.[3] In general, the intake has been designed and situated so as to minimize impingement possibilities.[3,8]

Table D.1. Summary of the Habitat Preference and Feeding Habits of Important Fish Species Occurring in the Vicinity of the BFS[a]

| Scientific Name (Common Name) | Relative Abundance[b] | Habitat Preference[c] | Major Food Items and/or Habits[c] |
|---|---|---|---|
| *Lepisosteus osseus* (Longnose gar) | Common | Quiet, weedy shallows of lakes or large rivers. | Feeds on dead and live fish; often lies quietly near surface waiting to feed. |
| *Lepisosteus platostomus* (Shortnose gar) | Common | Somewhat adapted for mainstream of large, muddy rivers, though prefers quiet pools and backwaters. | Feeds on surface invertebrates as well as fish. |
| *Dorosoma cepedianum* (Gizzard shad) | Abundant | Frequents large rivers; common and often abundant in backwaters. | Feeds on bottom and pelagic plankton. |
| *Hiodon alosoides* (Goldeye) | Uncommon | Frequents quiet, turbid waters of large rivers; overwinters in deeper areas of rivers. | Feeds on fish and invertebrates; in summer a large amount of food taken at surface. |
| *Cyprinus carpio* (Carp) | Common | Inhabits areas other than swift, rocky streams; prefers quiet, shallow water. | Feeds on bottom and surface. |
| *Notropis ortenburgeri* (Kiamichi shiner) | R-2 | Almost always found in relatively small to moderate-sized, clear, upland streams; also in relatively quiet water in pools and among large boulders. | Specifics unknown. |
| *Carpiodes carpio* (River carpsucker) | Common | Frequents quiet pools and backwaters. | Bottom feeder. |
| *Carpiodes velifer* (Highfin carpsucker) | R-2 | Prefers to remain out of river current. | Bottom feeder. |
| *Ictiobus cyprinellus* (Bigmouth buffalo) | Common | Inhabits shallow depths of slow, sluggish, or still waters of larger rivers; on warm days it hangs near surface. | Feeds on bottom organisms and plankton. |
| *Ictiobus bubalus* (Smallmouth buffalo) | Common | Similar to bigmouth buffalo, but prefers deeper, somewhat less turbid waters; less likely to be found in quiet waters and flooded habitats than bigmouth buffalo. | Mainly bottom feeder. |
| *Ictalurus punctatus* (Channel catfish) | Common | Usually inhabits cool, clear, deeper water; during day often in deeper holes in protection of rocks or logs. | Usually bottom feeder, but some feeding at surface. |
| *Ictalurus furcatus* (Blue catfish) | Common | Inhabits deeper portions of major rivers. | Omnivorous. |
| *Pylodictis olivaris* (Flathead catfish) | Common | Prefers deep holes and channels of large, sluggish rivers; often found in areas below navigation dams. | Mainly piscivorous, but will consume anything. |

Table D.1. Continued

| Scientific Name (Common Name) | Relative Abundance[b] | Habitat Preference[c] | Major Food Items and/or Habits[c] |
|---|---|---|---|
| *Labidesthes sicculus* (Brook silverside) | Common | Lives in surface layers; most of life spent less than two feet from surface. | Cladocera, *Chaoborus*, chironomids, and flying insects. |
| *Morone chrysops* (White bass) | Common | Prefers clear water; usually travels near surface. | Piscivorous and insectivorous. |
| *Lepomis cyanellus* (Green sunfish) | Common | Prefers shallows; frequents areas with brush piles and dense growth of emergent vegetation. | Insects, molluscs, and small fish. |
| *Lepomis gulosus* (Warmouth) | Common | Weedy or brushy habitats in quiet water; shallow mud-bottom lakes and sloughs or backwaters of rivers. | Insects, crayfish, and small fish. |
| *Lepomis macrochirus* (Bluegill) | Common | In rivers it inhabits heavily vegetated, slow-flowing areas; retreats to deeper areas in winter or hottest periods of summer. | Insects, crustaceans, and vegetation. |
| *Lepomis megalotis* (Longear sunfish) | Common | Usually in shallow, clear, nearly still, moderately warm water near areas of aquatic vegetation. | Invertebrates and some fish; feeds at surface more than other sunfish. |
| *Lepomis microlophus* (Redear sunfish) | Common | Tends to congregate about brush and stumps. | Invertebrates, especially snails. |
| *Micropterus salmoides* (Largemouth bass) | Common | Almost universally found associated with soft bottoms, stumps, and extensive growths of emergent and submergent vegetation. | Food taken at surface, bottom, and in water mass; usually feeds near shore and close to vegetation. |
| *Pomoxis annularis* (White crappie) | Common | Found in slow-moving areas of larger rivers; seems to congregate about brush piles or submerged trees. | Insects, crustaceans, and large number of small fish. |
| *Aplodinotus grunniens* (Freshwater drum) | Common | Deep pools of lakes and rivers. | Benthic macroinvertebrates and small fish. |

[a] List formulated from fish species commonly or abundantly collected by the applicant in the Verdigris River (ER, Table 2.2-107) and from fish species considered rare or endangered in Oklahoma ("Rare and Endangered Vertebrates and Plants of Oklahoma," 1975) that are actually or potentially present near the BFS.

[b] Relative abundance taken from the applicant's findings (ER, Table 2.2-107), except for those listed "R-2" ("Rare Species-R-2" for Oklahoma, see Sec. 2.7.2.8) and which were not collected by the applicant, but are potentially capable of being in the BFS area.

[c] Habitat preference and feeding habit data taken from: Scott and Crossman, "Freshwater Fishes of Canada," 1973; Eddy and Underhill, "Northern Fishes," 1974; Miller and Robison, "The Fishes of Oklahoma," 1973.

Table D.2. Swimming Speeds Observed for Various Fish Species

| Scientific Name (Common Name) | Fish Size | Current Withstood |
|---|---|---|
| *Morone saxatilis*[a] (Striped bass) | 3.0-5.5" | 2.0 ft/sec (for ten-minute period) |
| | 5.0-7.0" | 2.0 ft/sec for ten minutes; 2.75 ft/sec for ten minutes (except for one fish) |
| | 0.75-1.5" | 1.0 ft/sec (80% swimming after ten minutes) |
| *Morone saxatilis*[b] (Striped bass) | 1.38-5.20" (F.L.)[c] | 0.305-2.2 ft/sec (mean 0.94 ft/sec) for three minutes) |
| *Morone saxatilis*[d] (Striped bass) | Variable | 0.48 ft/sec/inch body length at 75-80°F (for three-minute test) |
| *Oncorhynchus tshawytscha*[a] (Chinook salmon) | 1.25-1.50" | 1.0 ft/sec (92% of 160 swimming after ten minutes) |
| *Alosa sapidissima*[b] (American shad) | 2.0-3.03" (F.L.) | >1.5 ft/sec (for three minutes) |
| *Alosa pseudoharengus*[b] (Alewife) | 2.4-3.31" (F.L.) | >1.3 ft/sec (except those in poor health) (for three minutes) |
| *Alosa aestivalis*[b] (Blueback herring) | 1.57-2.20" (F.L.) | >1.0 ft/sec, average 1.26 ft/sec (one fish tested did not swim over 1 ft/sec) (for three minutes) |
| *Fundulus diaphanus*[b] (Banded killifish) | 2.17-4.09" (F.L.) | 1.09-1.68 ft/sec (for three minutes) |
| *Perca flavescens*[b] (Yellow perch) | 3.62-4.25" (F.L.) | 1.54 and 1.73 ft/sec (for three minutes) |
| *Membras martinica*[d] (Rough silverside) | 3.58" (mean F.L.) | 0.7 ft/sec (for three minutes) |
| *Menidia beryllina*[d] (Tidewater silverside) | 2.44" (mean F.L.) | 1.7 ft/sec (for three minutes) |
| *Pomatomus saltatrix*[d] (Bluefish) | 2.09" (mean F L.) | 0.7 ft/sec (for three minutes) |
| *Anchoa mitchilli*[d] (Bay anchovy) | 2.44" (mean F.L.) | 0.5 ft/sec (for three minutes) |
| *Morone americana*[d] (White perch) | Variable | 0.394 ft/sec/inch body length at 80-90°F (for three minutes); 0.940 ft/sec/inch body length at 75°F (for three minutes) |

[a]From Kerr, "Studies on Fish Preservation at the Contra Costa Steam Plant of the Pacific Gas and Electric Co.," 1953.

[b]From Kotkas, "Studies of the Swimming Speed of Some Anadromous Fishes Found Below Conowingo Dam, Susquehanna River, Maryland," 1970.

[c]F.L. = Fork length.

[d]From Tatham, "Swimming Speed of the White Perch, *Morone americana*, Striped Bass, *Morone saxatilis*, and Other Estuarine Fishes," 1971.

The use of a presettling pond to store water for the BFS cooling system will make it possible to shut down the intake pumps temporarily without affecting station operation if fish occasionally become concentrated in the vicinity of the intake structure. In addition, gentle backwashing can be scheduled as needed to keep fish impingement low.

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APPENDIX E. PREFERRED SPAWNING SITES, EGG TYPES AND FECUNDITY VALUES OF SELECTED FISH AT BFS

Table E.1. Preferred Spawning Sites and Types of Eggs for Selected BFS Fish[a]

| Species | Spawning Site | Type of Egg |
|---|---|---|
| Longnose gar | Weedy beds | Adhesive |
| Shortnose gar | Weedy beds | |
| Gizzard shad | At surface | Sticky eggs that sink to bottom or drift with current |
| Goldeye | In ponds or backwater areas and over shallow, gravelly areas | Semi-buoyant |
| Carp | In shallows | Adhesive |
| Bullhead minnow | Eggs attached to underside of stones and other objects | |
| Kiamichi shiner[b] | Almost unknown, but habitat preferences would preclude open channels | |
| River carpsucker | Over tree roots and rushes in moderately deep water | |
| Highfin carpsucker[c] | Probably similar to river carpsucker | |
| Smallmouth buffalo | In small tributary streams and in marshes or flooded lake margins | Adhesive |
| Bigmouth buffalo | Eggs scattered in shallow weedy areas | |
| Channel catfish | In secluded, semi-dark nests made in holes, undercut banks, log jams or rocks | |
| Blue catfish | Similar to channel catfish | |
| Flathead catfish | In net depressions and holes under large stumps or brush piles in quiet water | |
| Brook silverside | In and around aquatic vegetation, but may also spawn over gravel in moderate current | Adhesive and filamentous |
| White bass | At surface | Heavy and adhesive |
| Green sunfish | Shallow water nests | Adhesive |
| Warmouth | Similar to green sunfish | |
| Bluegill | Shallow water nests | Adhesive |
| Longear sunfish | Shallow water nests | Adhesive |
| Redear sunfish | Similar to other sunfish | |
| Largemouth bass | In nests in shallow, quiet areas | Demersal and adhesive |
| White crappie | Ill-defined nests over variety of bottom types, usually near rooted plants or algae; or at undercut banks | Demersal and adhesive |
| Freshwater drum | | Buoyant and float at surface |

[a]Information derived mainly from: Scott and Crossman, "Freshwater Fishes of Canada," 1973; Eddy and Underhill, "Northern Fishes," 1974; Miller and Robison, "The Fishes of Oklahoma," 1973.

[b]Listed as "Rare-II" in Oklahoma ("Rare and Endangered Vertebrates and Plants of Oklahoma," 1975); not collected by applicant and may no longer be present in the Verdigris River.

[c]Listed as "Rare-II" in Oklahoma ("Rare and Endangered Vertebrates and Plants of Oklahoma," 1975); not collected by applicant but may be present in the Verdigris River.

Table E.2. Fecundity Values of Some Important Fish Species at the BFS

| Species | Eggs Produced[a] |
|---|---|
| Longnose gar | Average 3002 eggs/lb body weight in Mississippi, 77,156 eggs in a 32-lb fish in Florida |
| Shortnose gar | 36,460 eggs in a 4082 g female[b] |
| Gizzard shad | Average 379,000 for 2-yr-old fish, numbers decline in age 3 and older |
| Goldeye | 5761-25,238 for 12- to 15-inch females in Florida |
| Carp | 36,000 eggs in 15-inch fish to 2,208,000 eggs in 33.5-inch fish |
| River carpsucker | 4828-149,744 (mean 102,766) eggs/female; 4431-154,038 eggs/female[b] |
| Bigmouth buffalo | 750,000 eggs in a 26.2-inch female |
| Smallmouth buffalo | 5- to 6-lb fish average 230,000 eggs[c] |
| Channel catfish | 6900-11,300 eggs in 305-610 mm females[b] |
| White bass | Range from 20,000-300,000, depending partly on size of fish |
| Bluegill | 7200-38,184 in fish ranging from 5.5-7.2 inches (4670-224,900 fry may result from one nest) |
| Longear sunfish | 2360-22,119 eggs/female for 2- to 4-yr-old fish |
| Largemouth bass | 2000-109,314 or 2000-7000 eggs/lb of fish (751-11,457 fry may result from a nest; average = 5000-7000) |
| White crappie | Similar to 27,000-68,000 noted for black crappie; 4.3-inch female from Ohio contained 14,750 eggs |
| Freshwater drum | 43,000-508,000 eggs/female in Lake Erie sample (7 of 9 fish ranged from 209,000-341,000 eggs) |

[a]Values from reports listed by Scott and Crossman, "Freshwater Fishes of Canada," 1973, except as noted.

[b]Values from Carlander, "Handbook of Freshwater Fishery Biology," 1969.

[c]Values from Wrenn, "Life History Aspects of Smallmouth Buffalo and Freshwater Drum in Wheeler Reservoir, Alabama," 1968.

APPENDIX F. LETTER FROM U. S. DEPARTMENT OF THE INTERIOR, BUREAU OF INDIAN AFFAIRS

# United States Department of the Interior

BUREAU OF INDIAN AFFAIRS
MUSKOGEE AREA OFFICE
MUSKOGEE, OKLAHOMA 74401

IN REPLY REFER TO:
Land Operations

MAR 19 1976

STN 50-556/557

United States Nuclear Regulatory Commissi

Washington, D. C. 20555

Subject: Supplement No. 1 to environmental report for Black Fox Nuclear Generating Station, Units 1 and 2, Rogers County, Oklahoma (ER 76/11)

Dear Sirs:

This office has reviewed the supplement to the subject environmental report. There is no restricted Indian land involved in this project, and we have no comments as to any possible environmental effects.

Sincerely yours,

Alton R. Nordwall

Deputy Area Director.

cc:
Division of Trust Facilitation, Bureau of Indian Affairs, Washington, D.C. Attn: Environmental Quality, Code 210.



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## APPENDIX G. BFS SITE ECOSYSTEMS

Table G.1 summarizes the species composition of the various site ecosystems. Since the ecological dominants define the functional aspects of the ecosystem, only those species are included.

For woody plants, dominance was determined on the basis of importance percentages. The criterion for seedlings was set higher than for trees and saplings to reflect more accurately the probable future composition of the woods, assuming high seedling mortality. For the ground flora, relative frequencies were used as an index of dominance. The criteria used for woodland ground flora and for grassland ground flora were different. For woodlands, the ground flora represents one of the structural habitats, so lower values were accepted as indicators of dominance than were used for grasslands, where the ground flora is the dominant life form.

To determine dominance among animal species, the species were first ordered by relative abundance (or relative density); the cumulative relative abundance (or density) was used as the index of dominance. The species tabulated account for at least half of the total number of individuals sampled.

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Table G.1. Dominance Rank of Species in Terrestrial Communities at BFS Site

| Component | Terrestrial Plot[a] | | | | | |
|---|---|---|---|---|---|---|
| | A | B | D | E | F | H |
| **Tree stratum** | | | | | | |
| Black hickory | 3[b] | 2 | -[c] | - | - | - |
| Blackjack oak | 2 | X[d] | - | - | - | - |
| Post oak | 1 | 1 | - | - | - | - |
| **Sapling stratum** | | | | | | |
| Black hickory | 3 | 2 | - | - | - | - |
| Blackjack oak | 1 | X | - | - | - | - |
| Post oak | 2 | 3 | - | - | - | - |
| Winged elm | 4 | 1 | - | - | - | - |
| **Seedling stratum** | | | | | | |
| Blackjack oak | 1 | X | - | - | - | - |
| Post oak | 2 | 2 | - | - | - | - |
| Winged elm | X | 1 | - | - | - | - |
| **Ground flora** | | | | | | |
| Big bluestem | X | X | 1 | X | - | - |
| Little bluestem | X | - | 2 | 8 | 7 | - |
| Japanese brome | X | 0[e] | 9 | 2 | 4 | X |
| Bermuda grass | 0 | - | - | 0 | 0 | 1 |
| Beaked panicum | - | 0 | - | 1 | 0 | - |
| Scribner's panicum | 0 | 0 | 3 | 3 | 1 | - |
| Paspalum | - | X | - | 0 | 8 | - |
| Florida paspalum | - | - | 8 | 0 | 0 | X |
| Hurrahgrass paspalum | - | - | 7 | 4 | - | - |
| Yellow bristletail | 0 | 0 | 0 | 0 | 0 | 4 |
| Indian grass | - | - | 5 | 0 | - | - |
| Tall dropseed | - | - | 0 | 9 | 0 | - |
| Grasses[f] | X | X | 11 | X | X | X |
| *Carex*[f] | 2 | - | X | X | X | X |
| Sedges[f] | 1 | X | 4 | 5 | 5 | 2 |
| Elm[f] | X | 4 | - | - | - | - |
| Plains wildindigo | - | - | - | - | 11 | - |
| Virginia lespedeza | - | - | - | - | 5 | - |
| Lespedeza[f] | 0 | 0 | 0 | 7 | - | - |
| Catclaw sensitive briar | - | - | 10 | - | X | - |
| Virginia creeper | 3 | 2 | 0 | - | - | - |
| Coralberry | X | 1 | - | 0 | 0 | - |
| Western yarrow | 0 | X | X | 0 | 9 | X |
| Ragweed | X | X | - | 11 | 2 | - |
| Soft goldaster | - | - | - | X | 3 | - |
| Horseweed fleabane | 0 | X | - | 10 | 0 | - |
| Blackeyed susan | 0 | 0 | X | X | 10 | - |
| Ironweed | - | 3 | 0 | 0 | 0 | - |
| Forbs[f] | X | - | 6 | 6 | 6 | 3 |
| **Mammals** | | | | | | |
| Hispid pocket mouse | - | - | - | - | 3 | - |
| Eastern harvest mouse | X | - | 2 | 2 | X | 1 |
| Deer mouse | - | - | - | X | 1 | X |
| White-footed mouse | 1 | 1 | - | - | - | - |
| Hispid cotton rat | X | 3 | 1 | 1 | 2 | - |
| Eastern woodrat | X | 2 | - | - | - | - |
| Opossum | X | X | X | X | - | - |
| Eastern cottontail | - | - | X | X | - | - |
| Striped skunk | X | - | - | X | - | - |
| Raccoon | - | X | X | - | - | - |
| **Birds** | | | | | | |
| Carolina chickadee | 2 | 3 | - | - | - | - |
| Tufted titmouse | 3 | X | - | - | - | - |
| Blue-gray gnatcatcher | 1 | 1 | - | - | - | - |
| Eastern meadowlark | - | - | X | X | 2 | X |
| Cardinal | X | 4 | - | - | - | - |
| Indigo bunting | X | 5 | - | - | - | - |

Table G.1. Continued

| Component | Terrestrial Plot[a] | | | | | |
|---|---|---|---|---|---|---|
| | A | B | D | E | F | H |
| Birds (cont.) | | | | | | |
| Dickcissel | - | - | - | 1 | 1 | - |
| Savannah sparrow | - | - | 1 | X | - | 1 |
| Field sparrow | - | 2 | X | - | - | X |
| Invertebrates | | | | | | |
| Collembola | 2 | - | X | X | X | - |
| Hemiptera | X | 4 | X | X | X | - |
| Homoptera | 3 | X | 2 | 2 | 2 | - |
| Diptera | 4 | X | X | X | - | - |
| Hymenoptera | 1 | 1 | 1 | 1 | 1 | - |
| Isopoda | X | 2 | X | X | X | - |
| Araneida | X | 3 | X | X | X | - |

[a]Key to plots: A = xeric upland woods; B = mesic upland woods; D = prairie hay; E = lowland unimproved pasture; F = upland pasture; H = lowland improved pasture.

[b]Number denotes dominance rank, i.e., "3" indicates black hickory ranks third in terms of dominance in Plot A.

[c]- = Species not observed.

[d]X = Species present, but not one of the dominant species.

[e]0 = Species observed, but not found in quantitative samples.

[f]Species not identified.

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OAK RIDGE NATIONAL LABORATORY
OPERATED BY
UNION CARBIDE CORPORATION
NUCLEAR DIVISION

POST OFFICE BOX Y
OAK RIDGE, TENNESSEE 37830

December 1, 1976

Mr. Jack O. Roberts
Cost Benefit Analysis Branch
Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Roberts:

The results of the revised CONCEPT calculations you requested for the Black Fox Generating Station are enclosed.

Please note that, per your request, we have used the new PWR cost model for estimating the capital cost of the nuclear plant. The estimates for coal-fired plants are based on the old cost models. Hence, we expect that the attached estimates overstate the differential costs between nuclear and coal.

I am also enclosing copies of graphs showing the results of the regression analysis of historical site labor and materials cost data for the nuclear and fossil plants for Dallas.

Please contact me if I can be of further assistance.

Very truly yours,

B. H. Fitzgerald
for
H. I. Bowers
Engineering Analysis Section

HIB:BHF:sf

Enc.

cc: B. H. Fitzgerald
C. R. Hudson
M. L. Myers
J. Norris, NRC-E.P. Project Manager
J. C. Petersen, NRC
R. L. Spore

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## COST ESTIMATES FOR ALTERNATIVE BASE-LOAD GENERATION SYSTEMS

A recently developed computer program was used to rough check the applicant's capital cost estimate for the proposed nuclear power station and to estimate the costs for fossil-fired alternative generation systems.

This computer program, called CONCEPT[1-4] was developed as part of the nuclear assessment activities of the ERDA Division of Nuclear Research and Applications (formerly Division of Reactor Research and Development), and the work was performed in the Reactor Division at the Oak Ridge National Laboratory. The code was designed primarily for use in examining average trends in costs, determining sensitivity to technical and economic factors, and providing reasonable long-range projections of costs. Although cost estimates produced by the CONCEPT code are not intended as substitutes for detailed engineering cost estimates for specific projects, the code has been organized to facilitate modifications to the cost models so that costs can be tailored to a particular project. Use of the computer provides a rapid means of estimating future capital costs of a project with various assumed sets of economic and technical ground rules.

### DESCRIPTION OF THE CONCEPT CODE

The procedures used in the CONCEPT code are based on the premise that any central station power plant involves approximately the same major cost components regardless of location or date of initial operation. Therefore, if the trends of these major cost components can be established as a function of plant type, size, location, and interest and escalation rates, then a cost estimate for a reference case can be adjusted to fit the case of interest. The application of this approach requires a detailed cost model for each plant type at a reference condition and the determination of the cost trend relationships. The generation of these data has comprised a large effort in the development of the CONCEPT code. Detailed investment cost studies by an architect-engineering firm have provided basic cost model data for light water reactor nuclear plants, fossil-fired plants, and high-temperature gas-cooled reactor nuclear plants.[5,6] These cost data have been modified to reflect multiple-unit plant designs and to reflect plant design changes occurring since the reference date of the initial investment cost studies.[7-10] Cost models for flue gas desulfurization (FGD) equipment for fossil-fired plants are based on a study of limestone-slurry scrubbing performed by Oak Ridge National Laboratory.[11]

Each cost model is based on a detailed cost estimate for a reference plant at a designated location and a specified date. This estim te includes a breakdown of each cost account into costs for factory equipment, s  bor, and site materials. A typical cost model consists of over a hun  individual cost accounts, each of which can be altered by input at the use  option. The ERDA (formerly AEC) system of cost accounts[12] is used in CONCEPT.

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To generate a cost estimate under specific conditions, the user specifies the following input: plant type, location, net capacity, beginning date for design, beginning date for construction, beginning date for commercial operation, and rate of interest during construction. If the specified plant size is different from the reference plant size, the direct cost for each account is adjusted by scaling functions which define the cost as a function of plant size. This initial step gives an estimate of the direct costs for a plant of the specified type and size at the reference date and location.

The code has access to cost index data files for 20 major cities in the United States. These files contain data on wage rates for 16 construction crafts and unit costs for 7 site-related materials as reported by a trade publication over the past 15 years.[13] These data are used to determine historical trends in costs of site labor and materials, providing a basis for projecting future costs. These cost data can be overridden by user input if data for the particular project are available. Cost indexes and escalation rates for manufactured equipment must be specified by the user.

This technique of separating the plant cost into individual components, applying appropriate scaling functions and location-dependent cost adjustments, and escalating to different dates is the heart of the computerized approach used in CONCEPT. The procedure is illustrated schematically in Fig. 1.

ESTIMATED CAPITAL COSTS

The assumptions used in the CONCEPT calculations for this project are listed in Table 1. Plant capital investment estimates for the proposed nuclear station, utilizing mechanical draft cooling towers, are summarized in Table 2, and estimated costs for alternative coal-fired plants are presented in Table 3.

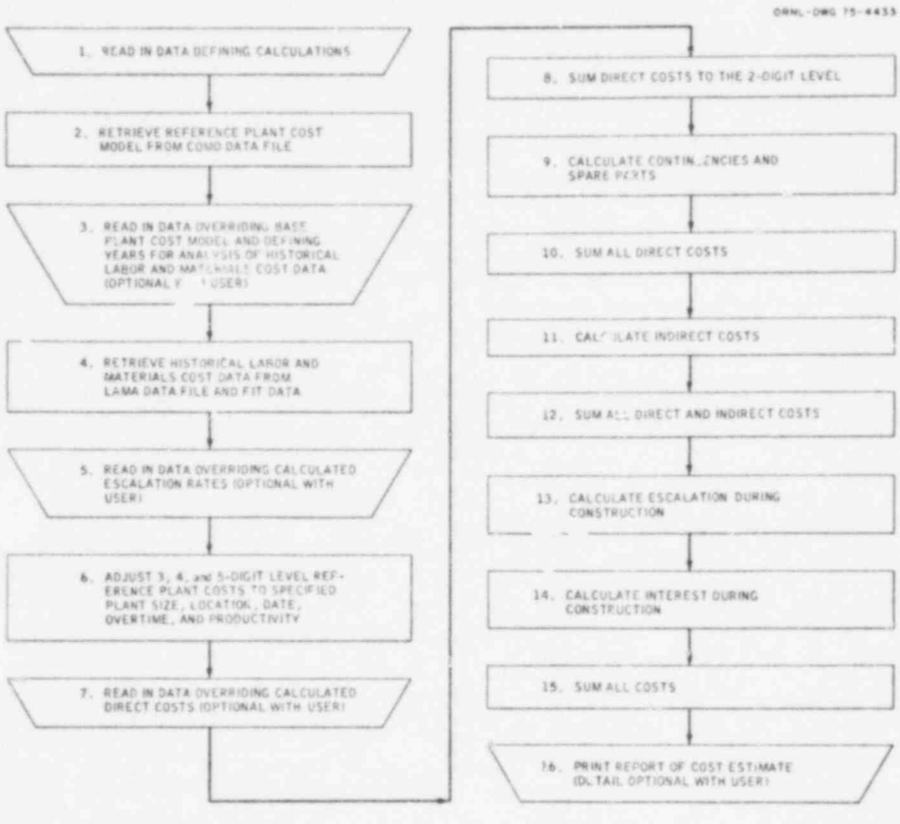


Fig. 1. Use of the CONCEPT program for estimating capital costs.

Table 1. Assumptions used in CONCEPT calculations for the Black Fox Generating Station

(Revised December 1, 1976)

| | |
|---|---|
| Plant type | PWR with mechanical draft cooling towers |
| Alternate plant types | Coal |
| Unit size | |
| Nuclear plant | 1220 |
| Fossil alternatives | 800 MWe-net, each unit |
| Plant location | |
| Actual | Inola, Oklahoma |
| CONCEPT calculations | Dallas |
| Site labor requirements | 10 mh/kWe - nuclear<br>8 mh/kWe - coal with FGD<br>6.5 mh/kWe - coal without FGD |
| Escalation during construction | |
| Purchased equipment | 6%/year |
| Site labor | 7.6%/year |
| Site materials | 4.7%/year - nuclear, 5.5%/year - coal |
| Interest during construction | 9%/year, compound |
| Start of design date | |
| NSSS ordered | December 1973 |
| Fossil alternatives | July 1977 |
| Start of construction date | |
| Nuclear plant | July 1977 |
| Fossil alternatives | July 1979 |
| Start of commercial operation dates | |
| Nuclear plant | July 1983 and July 1985 |
| Fossil alternatives | July 1983, July 1984, and July 1985 |

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Table 2. Plant capital investment summary for a pressurized water reactor nuclear power plant utilizing mechanical draft cooling towers

(Revised December 1, 1976)

(Public Service Company of Oklahoma, Black Fox Station)

| | Unit 1 | Unit 2 | Total |
|---|---|---|---|
| Net capability, MWe | 1220 | 1220 | 2440 |
| Direct costs (millions of dollars)* | | | |
| Land and land rights | 5 | 0 | 5 |
| Structures and site facilities | 95 | 87 | 182 |
| Reactor/boiler plant equipment | 141 | 141 | 282 |
| Turbine plant equipment | 122 | 122 | 244 |
| Electric plant equipment | 40 | 37 | 77 |
| Miscellaneous plant equipment | 11 | 8 | 19 |
| Subtotal | 414 | 395 | 809 |
| Spare parts allowance | 6 | 5 | 11 |
| Contingency allowance | 41 | 40 | 81 |
| Subtotal (direct costs) | 461 | 440 | 901 |
| Indirect costs (millions of dollars)* | | | |
| Construction facilities, equipment, and services | 77 | 40 | 117 |
| Engineering and construction management services | 82 | 36 | 118 |
| Other costs | 4 | 6 | 10 |
| Subtotal (indirect costs) | 163 | 82 | 245 |
| Total costs (millions of dollars) | | | |
| Total direct and indirect costs* | 624 | 522 | 1146 |
| Allowance for escalation | 141 | 154 | 295 |
| Allowance for interest | 304 | 371 | 675 |
| Plant capital cost at commercial operation | | | |
| Millions of dollars | 1069 | 1047 | 2116 |
| Dollars per kilowatt | 876 | 858 | 867 |

*In mid-1976 dollars

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Table 3. Plant capital investment summary for a 3-unit, 2400-MWe coal-fired plant utilizing mechanical draft cooling towers as an alternative to the Black Fox Station

(Revised December 1, 1976)

| | High-Sulfur, High Btu coal with FGD | Low-Sulfur, Low-Btu coal without FGD |
|---|---|---|
| Direct costs (millions of dollars)* | | |
| Land and land rights | 1 | 1 |
| Structures and site facilities | 80 | 71 |
| Reactor/boiler plant equipment | 292 | 286 |
| Turbine plant equipment | 195 | 189 |
| Electric plant equipment | 60 | 46 |
| Miscellaneous plant equipment | 10 | 9 |
| Subtotal | 638 | 602 |
| Spare parts allowance | 9 | 9 |
| Contingency allowance | 64 | 60 |
| Subtotal (direct costs) | 711 | 671 |
| Indirect costs (millions of dollars)* | | |
| Construction facilities, equipment, and services | 39 | 29 |
| Engineering and construction management services | 39 | 31 |
| Other costs | 26 | 23 |
| Subtotal (indirect costs) | 104 | 83 |
| Total costs (millions of dollars) | | |
| Total direct and indirect costs* | 815 | 754 |
| Allowance for escalation | 277 | 253 |
| Allowance for interest | 369 | 340 |
| Plant capital cost at commercial operation | | |
| Millions of dollars | 1461 | 1347 |
| Dollars per kilowatt | 609 | 561 |

*In mid-1976 dollars

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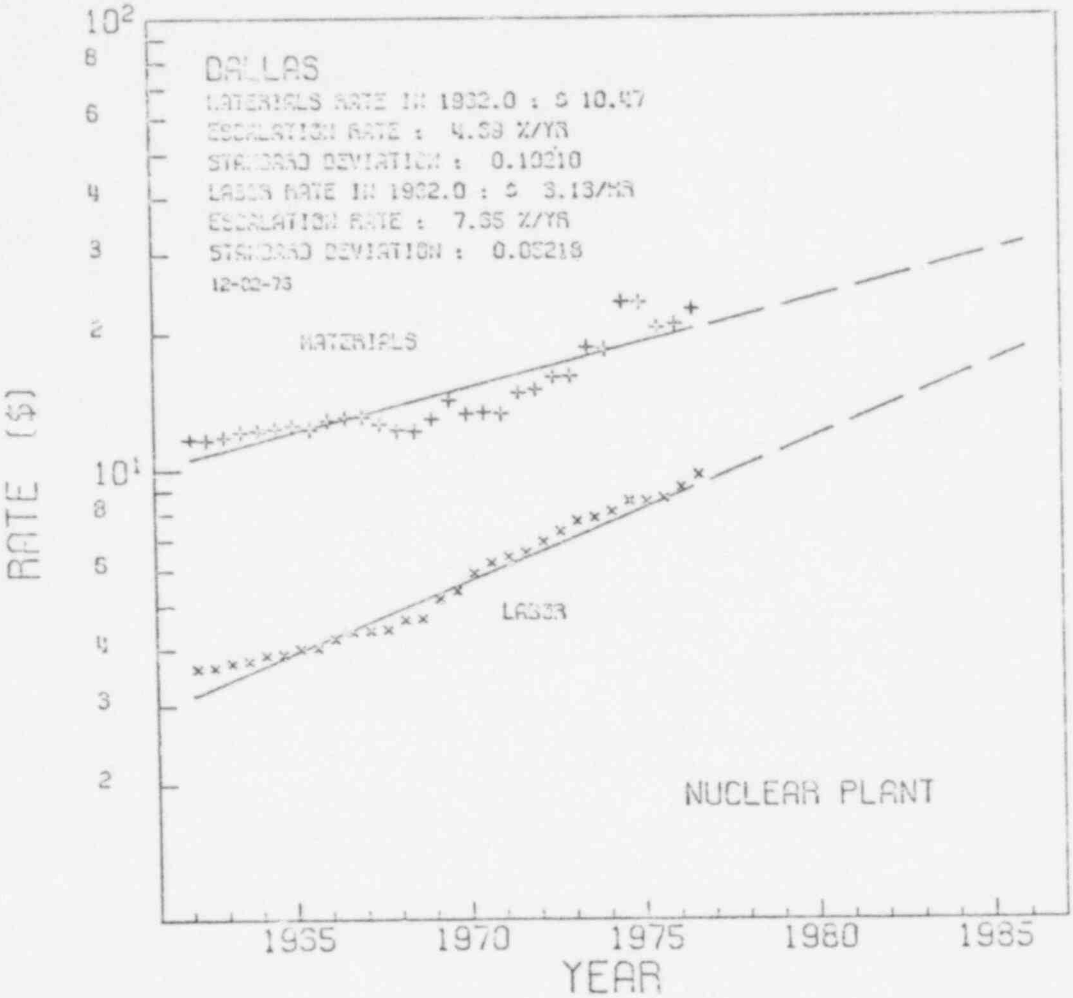




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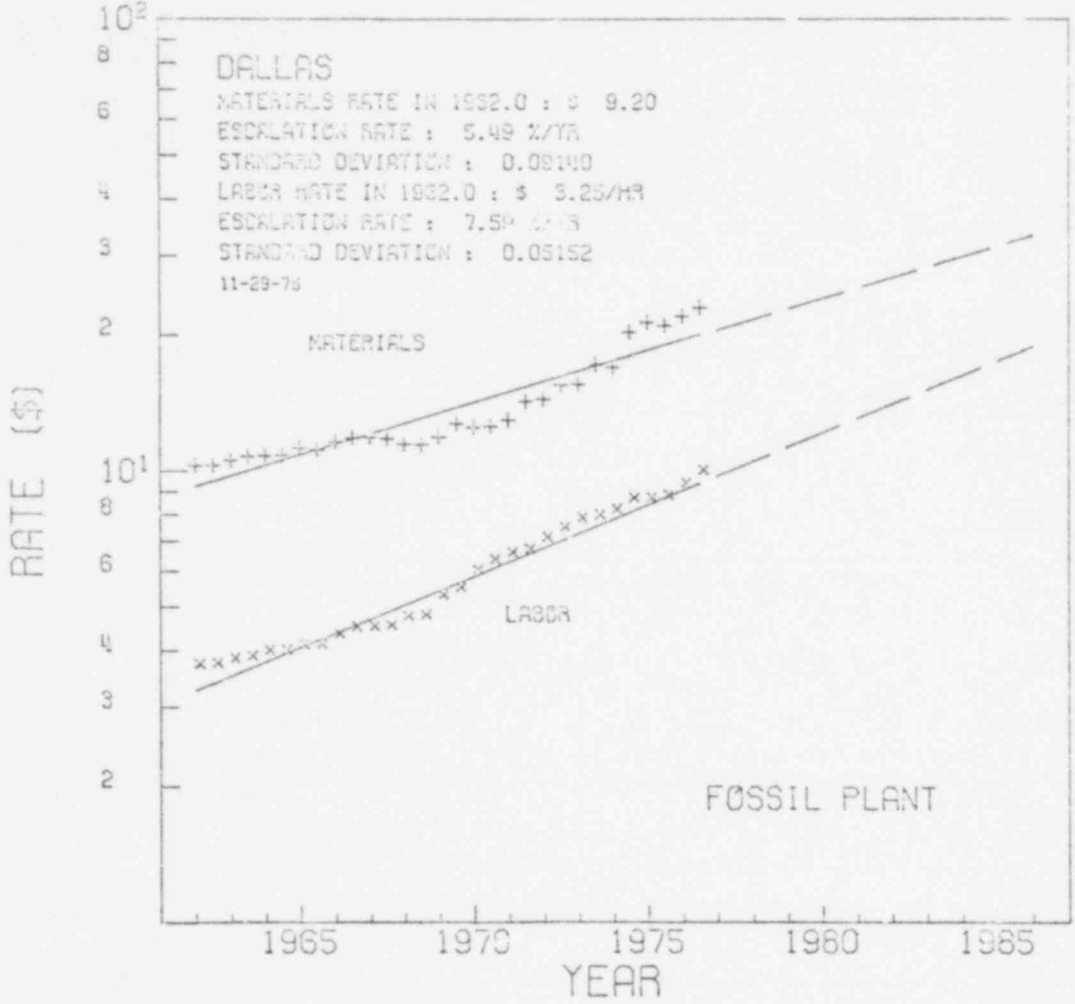


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APPENDIX J

# STATISTICAL ANALYSIS OF ELECTRIC PLANT CAPACITY FACTORS

Robert G. Easterling
Applied Statistics Group
U.S. Nuclear Regulatory Commission

## 1. INTRODUCTION AND SUMMARY

The data analyzed in this paper are the annual capacity factors* from coal-fired and nuclear electric plants. The results are of interest in describing what past performance has been and in using models developed from past data to predict the performance of future plants. Since predictions are of most interest for large capacity plants, we confine our attention in this analysis to generating units for which the generating capacity is rated at 500 megawatts (MW) or more. The period for which data were obtained is 1968 through 1975. Data from 33 coal-fired plants (a total of 154 observations) were obtained from FPC records and analyzed, and annual capacity figures from 32 nuclear units (a total of 97 observations) for the same period were obtained from NRC and FPC records, and analyzed.

The purpose of the statistical analysis is to determine what patterns of variation exist in capacity factors and whether any of these patterns are associated with readily identified features such as age or size of the plant. The statistical analysis in both cases - coal and nuclear - begins with the consideration of a balanced subset of the data. For coal plants, this subset was the first four years of operation of those plants which had attained that many years or more through 1975. Multiple unit plants were considered only if the multiple units came into service the same or consecutive years. For nuclear units (nuclear data are available on a unit basis while coal data are reported on a plant basis), the subset first considered was the first three years of operation for units which have had that many or more years. Without this sort of balance, average capacity factors, where the average is taken with respect to a size or age category, can be (and have been) misleading.

The statistical method used to investigate patterns of variability in these subsets is the analysis of variance, a procedure by which the total variation of a set of data is partitioned among possible sources of that variation. The sources considered for coal plants are age, size, and the number of units at the plant. For nulcear units, the sources of variation considered are age, size, and type (PWR or BWR). In both analyses we consider separately (1) the residual variation among different units or plants and (2) the residual variation from year to year within a plant or unit, whereby "residual" we mean the variation left over after accounting for such factors as age and size. Failing to make this separation leads to incorrect statistical conclusions about the effects of factors such as age and size.

The results of analysis of variance of the initial subsets indicate which sources of variation dominate the data and which sources have a negligible effect. The next step in the analysis is an analysis of variance of all the data in which the only sources of variation considered are those found to be important in the analysis of the initial subset. Comparing the results of the two analyses of variances then provides an indication of whether the patterns of variation in all the data are consistent with those found in the balanced subset. Additionally, the results of the analyses of variance are used to calculate prediction intervals, intervals which, under the assumption that future performance is consonant with past, are predicted to contain the achieved capacity factor of a future plant or unit, the prediction being made at some specified statistical confidence level.

For coal plants, the analysis indicates that neither unit size, nor age, nor number of units affected plant performance in any consistent way. However, it was found that year to year performance is correlated, that is, some plants have consistently high capacity factors, others consistently low. This result means that capacity factors for different plants tend to differ more than do the year to year capacity factors at a single plant. Not being able to identify

*A capacity factor is the ratio of the net electricity produced during a specified period to the amount which could have been produced in that period. In this analysis, this latter amount is determined from the generator nameplate rating.

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the source of this variation among plants makes predictions quite imprecise. For example, at the 95% level of confidence, a statistical prediction interval for the 10 year average capacity of a future plant is given by 56 ± 19%. For nuclear units, the results are more mixed. The capacity factors of large BWR's appear to decrease with increasing age. However, nearly all the data from units in this category are from four units - Dresden 2 and 3 and Quad Cities 1 and 2 - and for only 3 years of experience. Since these units were built by the same architect-engineer and construction firms and are operated by the same utility, there would appear to be a considerable degree of dependence among their performance and it is not clear how much weight should be given these results. Among the smaller BWR's and all Westinghouse PWR's, capacity factors do vary significantly with size, showing an average decrease of about 4 percentage points for each additional 100 MW of rated capacity over the range 500-900 MW. Nuclear units also show considerably more year to year variation in capacity factors than do coal plants but do not evidence as much year to year correlation as was found among coal plants. For making predictions, the lack of correlation more than offsets the large year to year variation, so that more precise predictions are obtainable. For nuclear plants, excluding large BWR's, a 95% statistical prediction interval for the 10 year capacity factor for an 800 MW unit, for example, is given by 54 ± 14%. Beyond 800 MW, the data are quite sparse and not conclusive as to whether the linear trend of capacity factors with size should extend to 1000 MW and beyond. Two Westinghouse units, Zion 1 and Zion 2, which have rated capacities of about 1100 MW, have operated at about 45% capacity, which is consistent with the line fitted to the bulk of the data, but one reason is the fact that these two units are restricted to 84% of design power. Of course, future units may also be restricted to reduced power so these data should not be discarded, only noted. In contrast, two BWR's of about 1100 MW attained capacity factors of 56% in their first year of operation and four Babcock and Wilcox (B&W) units in the 850-900 MW category have achieved capacity factors about 10 percentage points higher than what would be predicted from the fitted line. Thus, on balance, it seems reasonable to let the prediction interval for 800 MW units stand also for larger units.

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