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REPORT BY THE

Comptroller General

OF THE UNITED STATES

Coal Creek: A Power Project With Continuing Controversies Over Costs, Siting, And Potential Health Hazards

The Coal Creek power project is a joint venture by two rural electric power cooperatives financed by Rural Electrification Administration insured and guaranteed loans. The project has been beset by changing economic, environmental, and regulatory factors and by public opposition expressed in court suits and acts of vandalism.

Estimated costs have risen from $537 million in 1973 to over $1.2 billion in 1979. This report, made at the request of the Chairman, Subcommittee on Family Farms, Rural Development and Special Studies, House Committee on Agriculture, examines the

--large increase in costs;

--transmission line siting process in North Dakota and Minnesota; and

--potential adverse health and welfare effects from extra high voltage direct current transmission lines.

UNITED STATES GENERAL ACCOUNTING OFFICE

EMD-80-16

NOVEMBER 26, 1979

COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON, D.C. 20548

B-149244

The Honorable Richard M Nolan
Chairman, Subcommittee on Family
Farms, Rural Development and
Special Studies
Committee on Agriculture
House of Representatives

HSE00113

Dear Mr. Chairman:

In response to your request of December 5, 1978, here are the results of our review of the Coal Creek power project. Our report contains an analysis of costs incurred to construct the steam electric generating plant and transmission system and to develop the lignite coal field. It also discusses the transmission line siting process followed by North Dakota and Minnesota State regulators and the characteristics of extra high voltage direct current transmission lines as they relate to human health and welfare concerns.

As requested by your office, we did not obtain written comments on our draft report. The matters covered in this report, however, were discussed with cognizant Federal and State officials and with the utility cooperatives and they agreed with the findings and conclusions in the report. Their comments have been incorporated where appropriate.

As arranged with your office, we will not release this report to other interested parties for 7 days unless you publicly announce its contents earlier.

Sincerely yours,

Elmer B. Staats

Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT TO THE CHAIRMAN, SUBCOMMITTEE ON FAMILY FARMS, RURAL DEVELOPMENT, AND SPECIAL STUDIES, HOUSE COMMITTEE ON AGRICULTURE

COAL CREEK: A POWER PROJECT WITH CONTINUING CONTROVERSIES OVER COSTS, SITING, AND POTENTIAL HEALTH HAZARDS

D I G E S T

The construction of large, remotely-located electric generating powerplants has increased the need to expand high voltage transmission networks for transferring electricity from generating stations to distribution centers and for integrating these new units into reliable power supply systems.

The Coal Creek power project (see map p. 4) is the second major project in the United States to use extra high voltage direct current transmission lines to transmit electricity from a generating plant to distant distribution networks. This project has been the focus of much public concern in Minnesota because of the

--escalated construction costs for the generating station, transmission system, and coal mine development;

--siting and construction of the transmission system; and

--uncertainty about possible adverse effects of extra high voltage transmission lines on the health and welfare of humans, animals, and plant life.

PROJECT COST ESTIMATES HAVE DOUBLED

The cost of the Coal Creek power project increased from an estimated $537 million when it was proposed in mid-1973 to its present estimated cost of $1.2 billion. Some of these cost increases were beyond the control of the two cooperative utility companies constructing the project. For example,

--increasingly stringent Federal and State environmental and siting regulations required expenditures that were not anticipated, (see pp. 14, 15, 22-24, and 31.)

--interest on loan funds used during construction increased beyond expectations because of the greater amounts of capital required and the longer construction period, (see pp. 16, 27, and 31.)

--inflation rates were higher than expected, and (see pp. 16, 26, 27, and 30.)

--protests against the project led to court injunctions and to overt acts of vandalism that stopped and/or delayed construction. (See p. 26.)

Other cost increases resulted from management decisions such as

--redesigning major generating plant and coal handling components to increase generating capacity and reduce dependence on oil, (see p. 14.)

--providing the financing to develop privately-owned lignite coal reserves, and (see pp. 28 and 29.)

--requesting that transmission line siting and construction be brought under the Minnesota Power Plant Siting Act. (See p. 36.)

The wisdom of these management decisions will only be proven with the passage of time. GAO believes, however, that there was inadequate initial planning for a project of the magnitude envisioned and that the assumptions underlying the decision to proceed with the project should have been re-evaluated prior to starting construction as conditions changed following the 1973 feasibility study and the oil embargo.

ISSUES INVOLVED IN SITING POWER LINES

Much of the controversy surrounding the power project has revolved around the siting process followed by the rural electric cooperatives and State regulators and around the use of agricultural lands for siting transmission towers and power lines. On the siting issue, GAO found that

--the enactment of power plant and transmission siting laws in both North Dakota and Minnesota probably exacerbated the discontent of the rural landowners and served to increase project time and costs; (see pp. 6, 36, 45, 46, and 47.)

--North Dakota's application of siting procedures was minimal, whereas Minnesota's was more extensive and involved numerous public hearings on corridor and route selections; (see pp. 36-45.)

--North Dakota regulators gave greater consideration to avoiding agricultural lands than did Minnesota's, where environmental concerns were dominant;

--Minnesota regulators were less concerned with construction costs than were regulators in North Dakota; (see pp. 40 and 45.)

--the actual loss of land for crop use was not extensive, but factors such as aesthetics, access to rights-of-way, and disruptions to normal farming practices also needed to be considered; (see p. 35.)

--at least some of the delay, resentment, and siting costs could probably have been avoided if the Rural Electrification Administration and utility company officials had been more open with the public early in the siting process; (see pp. 5 and 6.)

--revisions to Minnesota's siting act could correct some of the inadequacies in the 1973 legislation; (see pp. 47 and 48.)

--the provisions for limiting use of prime farmland expressed in revisions to Minnesota's siting act could be offset by a Minnesota Supreme Court decision that holds that route selection must adequately reflect concern with Minnesota's commitment to the environment as expressed in the Minnesota Environmental Policy Act; and (see p. 49.)

--future transmission line siting responsibility in Minnesota appears to have been taken from the electric utilities and given to the State agencies and the public. (See p. 47 and 48.)

POTENTIAL FOR ADVERSE HEALTH EFFECTS FROM HIGH VOLTAGE POWER LINES

The minimal use of direct-current transmission lines in the United States has limited the amount of research effort expended compared to the more frequently used and researched alternating-current systems. Although there are a number of physical characteristics common to both types of transmission, there are sufficient differences that warrant separate research efforts.

Most of the direct-current research and operating experience to date has centered around the Bonneville Power Administration's direct current line from Oregon to California. This system has been operating since 1970 and was the first major direct-current system constructed in the United States. Although still in the early stages, other research groups are beginning to define direct-current exposure systems and instrumentation needed for performing laboratory biological studies. (See p. 63.)

GAO found no conclusive evidence in experiments and operational experience that being near such lines is a direct threat to human health. GAO further believes that actions taken by Minnesota State officials will serve to protect the public and the environment from adverse effects of the direct-current transmission system.

Agency officials made the construction permit for the line subject to more stringent requirements for design, construction, operation, and location in the future if research evidence indicates that such action is necessary to protect the public. (See pp. 59 and 63.)

They have also required the rural electric cooperatives to conduct a 2-year study of ozone generated by the transmission line. In addition, State officials will continue to monitor the results of direct-current research efforts. (See p. 56.)

Although the State health commissioner has concluded that the direct-current line poses no immediate danger to the public, he stated that more research is needed and publicly urged all individuals who believe they are being affected by the line to contact his department. (See pp. 62 and 63.)

AGENCY COMMENTS

GAO discussed this report with officials of Federal and State agencies and the electric utility cooperatives. They agreed with the findings and conclusions in the report.

Contents

APPENDIX

ABBREVIATIONS

a-c	alternating current
BPA	Bonneville Power Administration
CPA	Cooperative Power Association
dB (A)	Decibel
d-c	direct current
DOE	Department of Energy
EHV	Extra high voltage
EPRI	Electric Power Research Institute
GAO	General Accounting Office
G&T	Generation and Transmission
GE	General Electric
HVDC	High Voltage Direct Current
HVTL	High Voltage Transmission Line
IITRI	Illinois Institute of Technology Research Institute
kV	kilovolt
kW	kilowatt
MEQC	Minnesota Environmental Quality Council
MW	megawatt
PCA	Minnesota Pollution Control Agency
PEER	Persons for Enlightened Environmental Responsibility
ppm	parts per million
PSC	North Dakota Public Service Commission
REA	Rural Electrification Administration
UPA	United Power Association

CHAPTER 1

INTRODUCTION

In a December 5, 1978, letter, the Chairman, Subcommittee on Family Farms, Rural Development, and Special Studies, House Committee on Agriculture, requested that we examine certain specific issues concerning the construction of the Coal Creek power project by two Minnesota rural electric power cooperatives (app. I). This report addresses three of the seven issues enumerated in the letter: the major factors in the cost overrun of the project, the siting of transmission lines, and the human health effects of exposure to extra high voltage (EHV) transmission lines. The remaining four issues are addressed in another GAO report of the rural electrification program that is being prepared for release to the Congress.

DEVELOPMENT OF RURAL ELECTRIC COOPERATIVES

The transmission and distribution of electric power under the rural electrification program has become a large undertaking. From 1935, when the Rural Electrification Administration (REA) was established, through 1972, more than $8.36 billion had been loaned directly to cooperatives, public power districts, and others for electric power projects. From 1973 through 1978, an additional $10.1 billion was provided under REA's insured and guaranteed loan programs.

Before REA was established, many rural areas went without electric power. According to an REA publication, 89 percent of all farms in the United States were without central station electric service prior to 1935. Part of the reason given is that while some electric companies were willing to extend service to rural consumers, the price was prohibitive. As a rule, farmers had to pay from $2,000 to $3,000 per mile of line to obtain service and then had to pay higher rates than urban consumers. With REA funding and support, rural electric cooperatives were formed to build and maintain distribution systems to serve their rural members. For the most part, electric power was purchased from Federal power projects or privately owned utility companies by the cooperatives, transmitted to scattered power substations, and then distributed to consumers.

As the distribution network expanded throughout the rural areas the cooperatives began to form member-owned generation and transmission (G&T) cooperatives. Initially, these G&T cooperatives served largely as a service organization for the members, arranging for the purchase of bulk power supplies which were sold to members. Some of these G&T cooperatives also began to develop their own generating capability to supplement or replace power purchased from other utility companies. As the G&Ts developed, they joined regional power-sharing organizations that developed in the late 1960's and early 1970's. Under membership agreements in these organizations the G&Ts were expected to meet their own customer power demands. REA encouraged this practice and provided funds or loan guarantees for such purposes.

The Cooperative Power Association (CPA) and the United Power Association (UPA) are two such G&T cooperatives. CPA and UPA provide bulk electric power at wholesale rates to 34 distribution member cooperatives who in turn provide this power to 303,000 customers in 70 Minnesota counties and a small area in Wisconsin.

Cooperative Power Association

The Cooperative Power Association is located in Edina, Minnesota, and serves as the wholesale power supplier for 19 REA distribution cooperatives. These cooperatives provide energy to about 132,000 consumers in southwestern and west central Minnesota. CPA was incorporated on July 30, 1956, and shortly thereafter became the purchasing agent for its member systems. Until the Coal Creek project was entered into, CPA had no generating facility of its own. However, CPA owns and operates the transmission lines and all substations through which it receives power for its member cooperatives. CPA performs all of its maintenance and construction functions under contract with member systems, private utilities or independent contractors.

United Power Association

The United Power Association is located in Elk River, Minnesota. It serves as the wholesale power supplier for 15 distribution member cooperatives. These members provide power to 23 counties and over 171,000 consumers in eastern Minnesota and a small area in northwestern Wisconsin.

UPA was created on January 22, 1963 by two other generation and transmission cooperatives as a joint venture to construct a 166 megawatt (MW) generating plant at Stanton, North Dakota. In 1972 the two parent cooperatives--Rural Cooperative Power Association and Northern Minn. Power Assocation--merged with UPA and ceased to exist as separate entities at that time.

UPA had 216 MW of base load generation to meet normal demands and 21 MW of diesel-powered generation to meet peak demands. The base load generation was the 166-MW lignite-fired plant near Stanton, North Dakota, and a 50-MW coal-fired plant at Elk River, Minnesota. Peaking units are at scattered locations throughout the service area. UPA owned 1,789.6 miles of transmission line, 121 substations, various maintenance buildings, and dispatching facilities at Elk River. UPA handles all of its own maintenance activities.

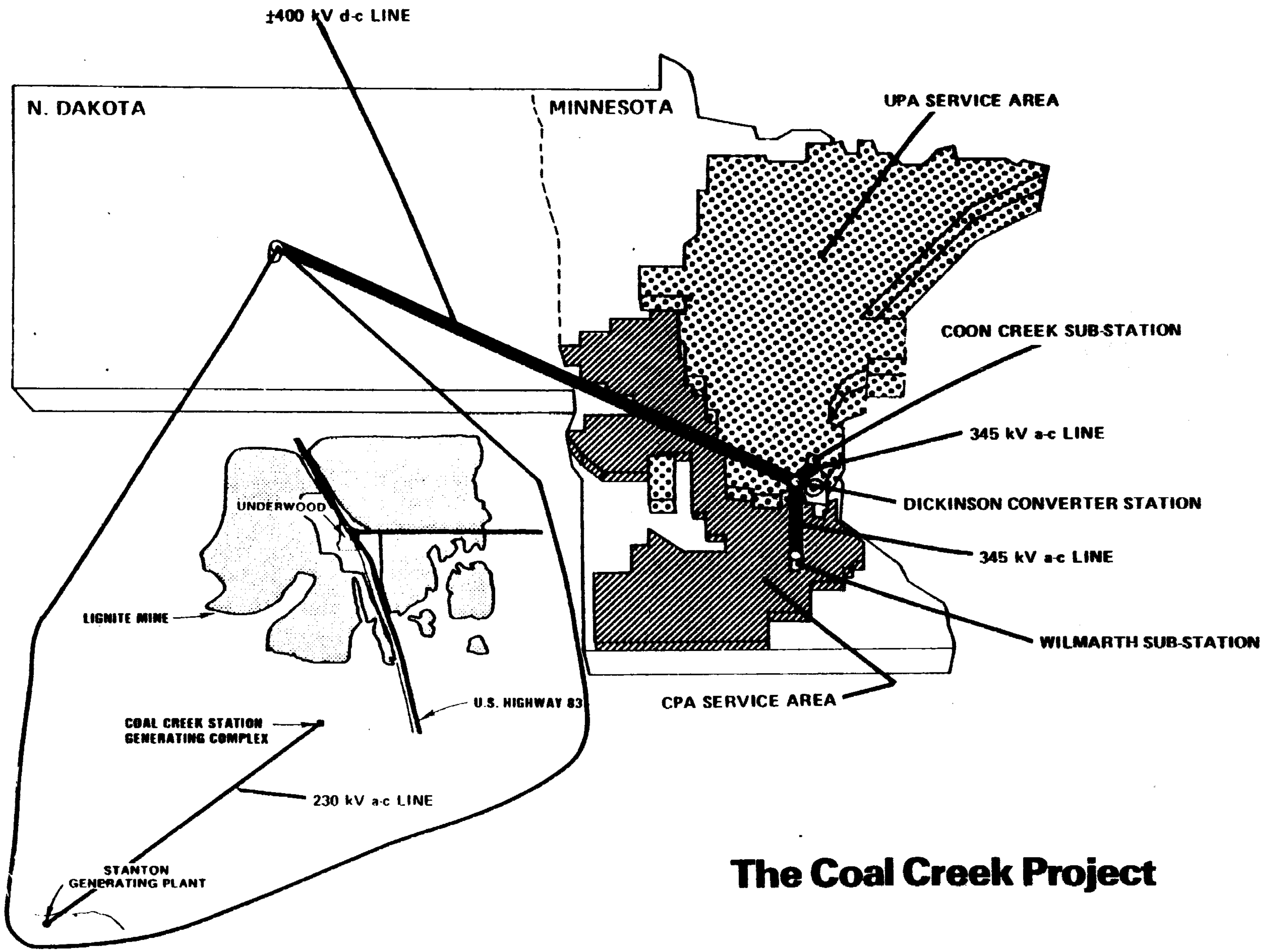
THE COAL CREEK POWER PROJECT

CPA and UPA conceived the idea of building a jointly owned steam electric generating plant in 1972. The exact location of the proposed plant was not specified at the time, but it was determined that about 800,000 kilowatts (kW) of additional generating capacity would be needed in the 1978-1982 period to take care of expected deficiencies in their power supply.

Project description

Following the completion of a feasibility study of the proposed generating facility in 1973, CPA and UPA signed a Memorandum of Understanding in which they agreed to build a lignite-fired generating plant located near the North Dakota lignite fields and related transmission facilities to bring the power from the plant to the utilities' service areas in Minnesota (see map). These planned facilities consisted of a 410-mile ± 450 kilovolt (kV) direct current line from the generating plant near Underwood, North Dakota, to Dickinson, Minnesota, plus alternating current/direct current (a-c/d-c) converter stations at Underwood and Dickinson; 12 miles of 230 kV a-c transmission line from Underwood to UPA's plant near Stanton, North Dakota, plus related substation equipment; and 83 miles of 345 kV a-c transmission line connecting the substation at Dickinson with substations at Wilmarth and Coon Creek, Minnesota. The cooperatives expected to buy their fuel supplies of lignite coal from the North American Coal Corporation. The coal company was already supplying lignite to UPA's Stanton plant and owned or leased large lignite coal reserves in the Underwood area.

The project differed from most power projects in two aspects: (1) lignite coal, although used by three REA-financed generating plants in North Dakota in 1973, is not a commonly used fuel for electric steam generation, and (2) most of the planned high voltage transmission system was d-c rather than the more commonly used a-c.



The Coal Creek Project

The Memorandum of Understanding specified that based on projected load requirements, CPA was to own a 56-percent share of the project and would be responsible for operating and maintaining the generating plant upon its completion. UPA was to own the remaining 44-percent share and was to be responsible for constructing the generating plant, transmission lines, and related facilities and for the operation and maintenance of the transmission facilities.

On November 29, 1973, CPA and UPA submitted requests to REA--who had been involved with CPA/UPA in planning the project--for $536,679,000 in insured and guaranteed loan funds to finance the Coal Creek project. REA approved the loan request on February 5, 1974.

CPA and UPA planned that one-half of the designed power output of the plant, or about 450,000 kW, would be available in 1978. The remaining output was expected to be available about a year later. These estimated completion dates have slipped by about one year and the initial cost estimate of $536.7 million for the proposed project has more than doubled.

Factors affecting project completion and cost

Reasons for the delay and cost overrun are numerous. Some involve internal decisions by CPA/UPA, but others involve external factors generally beyond their control. In order to better understand these reasons, a chronology of key events relating to the 8-year history of the project is included in appendix II.

One of the principal external factors affecting the project was the public opposition that developed in Minnesota over the construction of the $\pm$400 kV d-c transmission line. Beginning sometime in 1974, a strong protest movement against the power line began to be evident. Protesters expressed their concern over the lack of opportunity to be heard on issues such as the project's need, location, and cost. For example, the project was conceptualized in 1972 and largely formulated by mid-1973. REA issued a draft Environmental Impact Statement for the project in October 1973 and the Administrator elected not to hold public hearings because of the perceived lack of opposition. However, many individuals whose lives and property were to be directly involved did not learn about the project until the spring of 1974.

Many rural people doubted that the power project was needed. Although most of the transmission line is sited on agricultural land, they saw the main purpose of the line as bringing power into the area to serve the needs of suburban areas. The State added to the people's concern when it granted the cooperatives corridor approval for the transmission line before it determined the need for the power.

The strongest protests concerned the location of the EHV transmission line. Farmers and landowners felt that they had been abused by the utility cooperatives because powerlines constructed on agricultural lands could be disruptive to farming, reduce yields, and degrade the countryside aesthetics. They also noted that other land uses in the area seemed to have a special priority and were excluded from the powerline route. In addition, the people living near the powerline route became anxious and concerned about potentially adverse long-term health affects.

In a larger sense, the rural opponents to the power line were unhappy because of what they saw as an abuse of State authority. CPA/UPA first asked to be excluded from State siting procedures enacted after the project was started. Later when the cooperatives reached an impasse with county officials over construction permit approvals, they asked to be placed under the State regulations. Accompanying the rural resident's resentment of this belated use of State power to override local rules was the cooperatives' use of the power of eminent domain to obtain the necessary right-of-way for the line.

As project costs escalated, consumers began to be concerned over the price they would have to pay for power from the new plant. Some of the member cooperative officials expressed the feeling that they had not been well enough informed on the progress and cost of the project.

The concerns and complaints of the public have been presented in numerous court proceedings and State agency hearings. The end result was the decision to proceed with the project, but the polarization and suspicion that developed between CPA/UPA and the project opponents has continued. When the legal remedies requested by the opponents were not granted, acts of vandalism, and even violence, ensued.

SCOPE OF REVIEW

The Chairman's request letter included questions about the power project and REA activities. We had on-going reviews in the electric utility and REA areas, so the Chairman agreed with our proposal that we divide the request and incorporate the necessary audit work for the two areas in the scope of these two reviews. Consequently, we limited our audit work for this report to (1) ascertaining the primary reasons why the power project costs increased from $537 million to over $1.2 billion, (2) assessing the criteria used in siting the $\pm$400 kV d-c transmission line, and (3) reviewing the current status of research on potential health hazards from EHV d-c transmission lines. We did not fully assess the adequacy of project management or the reasonableness of actions taken by any of the involved parties because these areas will be covered in more detail in the REA report.

During the course of our review, we interviewed officials at REA headquarters in Washington, D.C.; CPA; UPA; and the Falkirk Mining Company in Bismarck, North Dakota. We also discussed various aspects of the project with officials and researchers at the Department of Energy, Washington, D.C.; the Bonneville Power Administration, Portland, Oregon; the Illinois Institute of Technology Research Institute, Chicago, Illinois; the Public Service Commission, Bismarck, North Dakota; the Minnesota Department of Health and the Environmental Quality Council; the University of Minnesota; and various opponents of the power line project.

We reviewed and/or analyzed numerous project documents including loan files, financial analyses and reports, construction and equipment contracts, and feasibility studies; studies and research reports on EHV transmission health hazards; and Federal and State environmental impact statements, siting regulations, corridor and route applications and maps, and hearing records relating to the power line siting issue. In addition, we visited the lignite coal mine and powerplant complex at Underwood, North Dakota; a section of the direct current transmission line in Minnesota, the Bonneville Power Administration's direct current test facilities at Vancouver, Washington, and The Dalles, Oregon; and a segment of Bonneville's Oregon-California EHV direct current transmission line.

CHAPTER 2

COAL CREEK POWER PROJECT

COSTS ARE MORE THAN DOUBLE

THE ORIGINAL ESTIMATE

The initial estimated cost of the total Coal Creek project was about $537 million. This cost included a steam electric generating plant with two 486,000 kilowatt units, a 410-mile EHV d-c line and two converter substations, and 95 miles of high voltage and EHV a-c lines. The completion cost for the powerplant and transmission system is now estimated at $1.03 billion--nearly twice the original estimate. The development costs of the adjacent coal mining complex were not included in the initial estimate but were later estimated to be $96 million. This cost subsequently increased to $215 million for a total project cost of about $1.2 billion.

As the project developed, it was divided into three major subsystems--the generating plant, the transmission complex, and the lignite coal mine. Each subsystem was engineered, contracted for, and constructed individually. Although there were common problems, each subsystem had its own peculiar set of circumstances that affected the project's final cost and completion date.

The following table shows the major categories of cost increase beyond what was initially estimated for each project subsystem.

Subsystem	Cost category	Estimated cost increase (millions)
Generating plant	1. Underestimated inflation rate	$89.0
	2. Underestimated interest during construction	69.0
	3. Unanticipated construction costs	31.0
	4. Design changes in plant and coal handling equipment	44.4
	5. Environmental concerns	31.0
Transmission line	1. Added construction costs, due to court actions, intervention, and regulatory requirements and process	53.0
	2. Underestimated interest during construction	29.0
	3. Increased contract costs due to unanticipated escalation clauses in contract	17.0
	4. Unanticipated right-of-way costs	25.6
	5. Vandalism and security costs	6.1
	6. Additional support items	11.5
Coal Mine Development	1. Pre-production interest on loan funds	47.6
	2. Additional equipment costs	58.3
	3. Capital costs not included in initial loan agreement	19.0

Many of the events that adversely affected the cost and timely completion of the project were beyond the control of CPA/UPA. Other events, however, resulted from deliberate management decisions. Design changes and equipment modifications, for example, were CPA/UPA decisions as was their request to put the transmission line siting process under the Minnesota siting act. In a project of this size and longevity, and considering the changing environment in which it will operate, the wisdom of those decisions will only be tested with the passage of time.

The decision by REA and the cooperatives to proceed with the project was based primarily on the operating record of three REA-financed generating plants in the North Dakota lignite coal fields. In 1973, these plants had some of the lowest generating costs in the country and REA and CPA/UPA officials believed that the Coal Creek project would be equally successful.

Within the limited scope of our review, we believe that the basic underlying causes of the problems encountered by the cooperatives in constructing the Coal Creek project were the inadequate front-end planning for the project and numerous premature commitments which REA and the cooperatives made lacking sufficient information.

POWER PLANT COST INCREASES

Estimated capital costs for the 2-unit generating plant increased from $370 million in 1973 to $717.3 million in 1978. This increase in estimated costs occurred primarily because

--the initial cost estimate was understated because the contingency allowance and interest costs on construction funds were too low;

--actual inflation rates were much higher than anticipated;

--major design changes were made because of anticipated effects of the oil embargo, regulatory requirements, and more detailed economic analyses; and

--delays in construction starts caused by State regulations and labor problems required accelerated construction schedules which increased contractor costs.

Project feasibility study

On November 2, 1972, CPA/UPA authorized Burns and McDonnell, an engineering consulting firm, to make a feasibility study for an electric powerplant. The plant was to meet increased power requirements expected during the 1978-1982 period. The consultants considered various energy sources and plant locations and determined that the most reasonable alternatives for the utilities' requirements were

--a mine-mouth generating station located adjacent to the lignite coal fields of North Dakota with EHV electric transmission service to Minnesota, or

--a generating plant located near the utilities' electric load center in Minnesota with transportation of coal by unit train from western coal fields.

Burns and McDonnell proposed the mine-mouth alternative based on cost and environmental considerations. The North Dakota alternative offered an expected savings, over a 10-year period, of about $73 million on a cash basis and $39 million on an accrual basis. The North Dakota selection eliminated a substantial movement of coal trains each year through the communities along the 700 miles of rail line in Minnesota, North Dakota, and Montana. A North Dakota mine-mouth plant would also reduce consumption of diesel oil by additional coal trains that would have been required by a plant located in Minnesota.

Description of the proposed plant

Burns and McDonnell envisioned a 3-unit lignite-fired plant with a gross capacity for each unit of 486,000 kilowatts. The feasibility study, however, proposed constructing only the first two units. The plant would take cooling water from the Missouri River, circulate it through two cooling towers, and then store it onsite in evaporation ponds. UPA officials told us that Federal water pollution control legislation 1/ prompted the decision to use cooling towers in conjunction with a zero-discharge system. As a result of this legislation, it appeared that the Federal Government was establishing zero discharge as a goal to be achieved by 1983.

1/Federal Water Pollution Control Act amendments of 1972 (P.L. 92-500).

The feasibility study stated that the North American Coal Corporation had some 300 million tons of lignite coal reserves located in the area immediately north of the proposed plant site that could provide adequate fuel for the estimated life of the plant--35 years for the first two units and 30 years for the third. Burns and McDonnell anticipated delivery of lignite coal from the surface mine to the plant site by off-highway trucks.

Burns and McDonnell's method of estimating

Burns and McDonnell estimated the capital cost of the proposed plant to be $370.9 million, and this figure later became the basis for REA's loan to CPA/UPA. In estimating costs for such large items as turbine generators and boilers, Burns and McDonnell contacted manufacturers and obtained estimates for budget purposes. They priced smaller equipment by using actual bids taken on other similar generating facilities under design by their engineers. These costs were then escalated to the estimated bid dates for the proposed project. Burns and McDonnell handled construction contracts in a similar manner.

The capital cost estimates were based on several assumptions about future events:

--Normal productivity of the labor force that had been experienced in the area.

--The absence of unusual or prolonged labor interruptions.

--Local governments' construction permits would be readily obtained.

--An adequate labor supply.

--Normal contingencies.

--Minimum winter construction.

--A low inflation rate during the construction period.

Burns and McDonnell included a 5-percent contingency fund in their estimate to cover unanticipated costs. To account for the effects of inflation on construction costs, Burns and McDonnell increased their 1973-based cost estimates to the anticipated commercial operation dates of the units in 1978 and 1979. Based on a number of indices, and the Federal

Government's stated policy to reduce inflation, the following rates were used in increasing labor and equipment costs:

Equipment and labor	Inflation rate
Boiler	6% per year
Turbine generator	8% per year
Mechanical and electrical equipment	6.5% per year
Construction materials and labor	8% per year

Interest during the construction period of 14 percent (7 percent interest for 2 years) was included in the estimate. This interest cost covers only loan receipts obtained during the construction period. Repayment of principal during the period was deferred but interest payments were not and began accruing as soon as funds were disbursed.

Increased costs resulted from a number of factors

Subsequent to REA's acceptance of the cost estimate prepared by Burns and McDonnell, a number of events occurred that greatly increased the cost of the generating plant. Most of the changes resulted from developments that were beyond the control of the utilities. Some increases were a response to changed conditions. Other cost increases resulted from the utilities' own decisions to do things differently than planned.

First cost revisions

Soon after the completion of the feasibility study, CPA/UPA decided to construct the recommended powerplant and retained the firm of Black and Veatch as the engineer for the design and construction of the plant. Before construction began, Black and Veatch revised the cost estimate contained in Burns and McDonnell's feasibility study to reflect what they considered was a more realistic estimate.

In a December 14, 1973 letter, Black and Veatch provided UPA a revised cost estimate of $413.5 million for the Coal Creek plant. This represents an 11.5 percent increase, or $42.6 million, over Burns and McDonnell's estimate of $370.9 million. Black and Veatch attributed the additional cost to (1) increasing the contingency fund from 5 percent--which they assessed as being too low for a project of this size and scope--to 10 percent, (2) increased environmental costs, and (3) additional interest during construction.

Redesign of powerplant and related facilities also added costs

The Burns and McDonnell feasibility study called for two generating units with a gross output capacity of 486,000 kilowatts each. Black and Veatch analyzed the steam cycle design and determined that larger steam boilers could utilize the full capacity potential of the proposed turbine generators. Subsequently, CPA/UPA decided to install larger boilers and increase the capacity of the units from 486,000 to 550,732 gross kilowatts at an incremental cost of $200 per kilowatt. The larger steam boilers, and the increased size of supporting auxiliary equipment, increased total plant cost by $22.8 million over Black and Veatch's earlier estimate of $413.5 million. Although this design change increased the plant's estimated cost markedly, it appears to have been a cost-effective decision. Plant capacity was increased by 13.3 percent while plant cost increased only 5.5 percent.

The 1973 oil embargo affected the Coal Creek project in several ways. The embargo created serious concerns about the availability of diesel and fuel oil in North Dakota. Under the original concept, lignite would have been trucked from the mine to the plant and the auxiliary boilers were to have been fired by oil. CPA/UPA proposed to insure the operation of the plant if oil products became scarce in the future. They decided to construct a $15.8-million electric-driven coal conveyor from the edge of the mine property to the plant to avoid reliance on diesel fuel. In addition to reducing oil consumption, the cooperatives decided the utilization of electric driven conveyors would also eliminate a substantial road dust problem, loss of fuel from heavy winds, and other ecologically related considerations.

Sulfur scrubbers used at the powerplant require lime to stabilize the scrubber waste, and this was to be transported to the plant site by rail. The cooperatives decided to modify their fly ash handling system in such a manner that they might use some of the ash with the scrubber waste, thus reducing both the need for lime and the plant's dependence on the railroad. Additional ash ponds were added to increase storage capacity from 15 years to the life of the plant. This design change required an additional expenditure of $7.5 million.

Energy and environmental concerns that developed during and after the oil embargo encouraged the cooperatives to change the scope of the original estimate. Auxiliary boilers were redesigned to burn coal rather than oil, pretreatment facilities for powerplant water needs were built, and evaporation ponds were added to maintain a zero pollutant discharge level. These changes resulted in an additional expenditure of more than $31.0 million.

According to Black and Veatch, their original 1973 estimate did not adequately consider the extreme winter weather conditions existing in North Dakota. The freezing temperatures required additional costs for heating systems, foundation costs to prevent frost damage, and additional burial depth for underground piping and duct banks. Environmental regulations magnify these costs because the required cooling towers and waste water treatment facilities had to be protected from the extreme winter conditions. Prior to 1973, power stations designed by Black and Veatch did not require environmental controls of this complexity, and they had no previous experience to draw upon when they made their original estimates.

Delays resulted in costly accelerated construction work

About 130 major contracts were awarded in constructing the powerplant. Black and Veatch and the utilities demanded tight scheduling of contracting phases to minimize the overall construction period; a tight schedule minimizes interest costs. CPA/UPA scheduled the project to begin October 1974, but the start was delayed until May 1975, because of difficulties in obtaining a construction permit from the North Dakota Department of Health and an unusually wet spring.

Labor problems also caused delays and schedule problems. For example, the mechanical contractor stopped work near the end of 1976 and abandoned the job in February 1977. Another contractor was selected but this action resulted in delaying the work. These delays caused increased winter construction that resulted in poor productivity and increased costs to contractors for which they demanded compensation. A contractor whose work had to be rescheduled because of the late arrival of owner-furnished material, or other delays, was entitled to extra compensation. Because of the required winter construction and extra contractor compensation, the utilities decided to accelerate the project by using double shifts. To cover additional claims for accelerated schedules, winter construction, construction costs of ash disposal ponds, and costs due to the delay of station auxiliary power startup, REA increased the amount for contingencies in the 1978 budget by $31.1 million.

Contracting problems

In 1974 and 1975 many contractors and equipment supply firms refused to quote firm prices on bid proposals and would only enter into contracts that contained escalation clauses based on indices prescribed by the Bureau of Labor Statistics. Unable to obtain firm bid prices, the cooperatives and REA accepted bids containing inflationary clauses. The contracts tied the cooperatives to the national inflation rates for steel, labor, and other materials. As an example of the effects of these contract terms on the project, utility construction costs increased about 25 percent in 1974 alone. For the period January 1973 through December 1979, construction costs in general increased 65 percent. These unavoidable contract terms created cost overruns beyond the control of the cooperatives.

Many of the Coal Creek plant contracts contained unit pricing clauses that allowed the cooperatives to increase the scope of the contract based on certain unit costs such as the hourly cost of workers or the cost to install a defined unit of work (i.e., piping installation, electrical cable installation, etc.). Unit pricing, which may also be subject to inflation if additional work is undertaken, allows the cooperatives flexibility in dealing with minor design changes. These costs, however, increase the original contract value and become a portion of cost overruns.

Interest during construction

The capital required to cover interest on loan funds during the construction period is determined by the length of the construction period and the amount of money needed. Construction delays of almost one year and increased capital needs of about $245 million caused interest costs to increase about $69 million.

Verification of increased costs

Although the cooperatives cited various generalized reasons for the plant overruns, they had not quantified each type of overrun on a total plant basis. CPA/UPA managed the plant construction on a contract basis and due to the volume of contracts and amendments, the job of quantifying each type of overrun would be a considerable task.

Each time a contract was amended, the reasons for any additional cost were documented. We examined 6 major contracts and the 26 associated amendments representing over 12 percent of Black and Veatch's 1977 estimated plant costs (less interest) to verify UPA, REA, and Black and Veatch's