United States General Accounting Office

GAO

Report to the Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Representatives

July 1989

SYNTHETIC FUELS

An Overview of DOE's Ownership and Divestiture of the Great Plains Project

139103

GAO

United States
General Accounting Office
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Resources, Community, and
Economic Development Division

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July 14, 1989

The Honorable Philip R. Sharp
Chairman, Subcommittee on Energy
and Power
Committee on Energy and Commerce
House of Representatives

Dear Mr. Chairman:

As you requested, this report provides an overview of (1) how the Great Plains coal gasification project performed under the Department of Energy's (DOE) control and ownership and (2) the project's divestiture. It represents the culmination of our work for your Subcommittee on the Great Plains project and draws from our past reports and testimony on the project.

As arranged with your office, we plan to distribute copies of this report to the Secretary of Energy and other interested parties and make copies available to others upon request.

Major contributors to this report are listed in appendix I.

Sincerely yours,

Keith O. Fultz

Keith O. Fultz
Director, Energy Issues

Executive Summary

Purpose

On August 1, 1985, the owner of the Great Plains coal gasification project defaulted on a $1.54 billion loan that had been guaranteed by the Department of Energy (DOE) for the construction and startup of the nation's only commercial-scale plant producing pipeline quality synthetic natural gas from coal. Following the default, DOE acquired control of, and title to, the project. About 3-1/4 years later, DOE sold the project for an estimated net present value of about $600 million.

As requested by the Chairman, Subcommittee on Energy and Power, House Committee on Energy and Commerce, this report provides an overview of how the project performed under DOE's control and ownership and the project's divestiture. The information draws from past GAO reports and, as agreed, concludes GAO's work for the Subcommittee on this project.

Background

In January 1982, DOE guaranteed a loan for the construction and startup of the Great Plains project. A partnership of five energy companies completed the project construction in December 1984 at a total cost of about $2 billion. The partners borrowed about $1.54 billion under DOE's loan guarantee and contributed about $493 million in equity to the project.

On August 1, 1985, the partnership defaulted on its loan, and DOE acquired control of, and then title to, the project. DOE continued to operate the plant, through the ANG Coal Gasification Company (ANG), and sell synthetic natural gas to four pipeline companies under 25-year contracts. In February 1986, DOE announced it would sell the project with the objective of (1) removing the federal government as a gas production competitor, (2) selling the project for as much as possible, and (3) assuring long-term operations. On October 31, 1988, DOE sold the project to two subsidiaries of Basin Electric Power Cooperative.

Results in Brief

During the 3-1/4 years that ANG operated the project for DOE, it performed well, generally producing synthetic natural gas at levels above its design capacity. However, the project had high sulfur emissions, and to help the new owner resolve this problem, DOE provided $30 million of project funds for plant modifications to reduce sulfur emissions. Under DOE's control, the project's revenues exceeded its expenses (excluding plant depreciation) by about $110.3 million, and the project's cash balance increased from $1.4 million to $137.8 million. DOE's divestiture process took nearly 3 years after soliciting statements of interest in acquiring the plant from the public and private sector. It involved the marketing efforts of Shearson Lehman Hutton, Inc., congressional oversight, and discussions with 17 prospective buyers. The sale terms are complex, and it may be many years before the total proceeds to the government from the sale are known. Those proceeds will ultimately be determined by future prices for the project's synthetic natural gas. Also, Shearson disagreed with DOE on its marketing fee; DOE paid Shearson $1.2 million, and Shearson wants $3.4 million.

Principal Findings

Project Performance

While under DOE's control and ownership, the project was a technical success. It produced an average of about 138 million cubic feet (MMcf) of synthetic natural gas per day, or about .5 MMcf per day above its design capacity rating, except for 3 weeks when it was shut down from a fire. Monthly average daily gas production exceeded 145 MMcf several times and fell below 130 MMcf only when the plant was partially shut down for maintenance or shut down from the fire. When the project was sold, however, it had not yet obtained an Air Pollution Control Permit to Operate because of the plant's high sulfur emissions. DOE provided $30 million from project funds for the new owner to use to meet sulfur emissions requirements.

During DOE's control and ownership, project revenues totaled about $658.3 million and exceeded expenses, excluding plant depreciation, by about $110.3 million. About 90 percent of the revenues were generated from gas sales at higher than market prices, and the rest were derived from pipeline transportation charges, by-product sales, and interest earned on cash investments. The cash balance increased from $1.4 million when DOE assumed control to $137.8 million when the project was sold.

Project Divestiture

In February 1987, DOE awarded Shearson a contract to assist in selling the project. In October 1987, Shearson began marketing the project, and 9 of the 17 prospective buyers submitted firm offers. After extensive negotiations, DOE announced on August 5, 1988, that it had selected Basin as the buyer because Basin had agreed to waive production tax credits, made the highest offer, and had the strongest commitment for long-term project operations. DOE estimated that Basin's offer had a net present value of about $600 million. The sale closing took place on October 31, 1988.

On October 21, 1988, GAO issued a report on its analysis of DOE's estimate of Basin's offer. GAO concluded that DOE's $600 million net present value estimate should have been reduced by about $397 million because DOE (1) should not have included the $300 million in waived production tax credits, (2) should not have included project cash of $82 million which already belonged to DOE, and (3) should have reduced the sale value by $15 million that DOE had agreed to provide as working capital for the new plant owner. These exclusions would have reduced the net present value of Basin's offer to about $203 million.

Sale Agreement

Basin established two subsidiaries to own and operate the Great Plains project and coal mine. Under the sale agreement, the Dakota Gasification Company acquired the gasification plant and pipeline and the Dakota Coal Company acquired the mining assets. The two subsidiaries paid DOE $85 million at closing, and Dakota Gasification agreed to share future revenues with DOE contingent upon future gas prices.

Under the terms of the sale agreement, DOE provided $120 million of project funds to (1) establish a $30 million environmental trust fund, (2) set up a $75 million cash reserve trust fund to provide loans to Dakota Gasification for project operations under certain adverse conditions, and (3) contribute $15 million in working capital for project operations. The sale agreement also requires that DOE must be provided certain reports and other notifications to enable DOE to ensure that Basin and its subsidiaries comply with the terms of the sale agreement. Terms of the sale agreement are complex, and it took DOE and the new plant owner several months to agree on purchase price adjustments.

DOE paid Shearson $1.2 million for assisting in selling the project. In determining Shearson's fee, DOE applied the fee formula in its contract with Shearson to the $85 million DOE received at the sale closing and the present value of estimated future revenue-sharing payments. However, Shearson claims that its fee should be $3.4 million. Shearson contends that DOE should have included the present value of the waived production tax credits and the cash that DOE deposited in the project's trust fund and that the present value of future revenue-sharing payments should be at least $42 million higher than DOE estimated.

DOE believes that the value of waived production tax credits and the project trust fund are inappropriate for inclusion in the fee calculation. In its October 21, 1988, report on the sale value, GAO concluded that neither production tax credits nor project cash should be included in calculating the value of the sale to the government. DOE expects Shearson to contest the fee before DOE's contract review board or in court.

Effect of Future Energy Prices

The project's future gas prices will affect revenue-sharing payments to the government, the use of the $75 million cash reserve fund, and Dakota Gasification's commitment to continue project operations. GAO estimated how long Dakota Gasification would continue to have a positive cash balance. GAO's analysis indicated that the company would run out of cash in 1991 using Wharton Econometrics' energy price forecasts and in 1992 using Data Resources, Incorporated's forecasts. DOE's analysis indicated that Dakota Gasification would run out of cash in 1994. However, Basin has stated that it is committed to continued long-term plant operations because if the project were closed, Basin would lose net revenues of about $37 million annually from the sale of electricity to the project.

Recommendations

GAO is not making recommendations in this report.

Agency Comments

GAO obtained and incorporated the views of DOE officials on the factual information presented. However, as agreed with your office, GAO did not obtain official agency comments on a draft of this report.

Contents

Figures

Abbreviations

ANG	ANG Coal Gasification Company
Btus	British thermal units
DOE	Department of Energy
DRI	Data Resources, Incorporated
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FFB	Federal Financing Bank
GAO	General Accounting Office
GPGA	Great Plains Gasification Associates
MMcf	million cubic feet

Introduction

On January 29, 1982, the Department of Energy (DOE) awarded a loan guarantee to the Great Plains Gasification Associates (GPGA), a partnership of five energy companies,[1] for the construction and startup, in North Dakota, of the nation's only commercial-scale plant producing pipeline quality synthetic natural gas from coal. The federal government, through the Department of the Treasury's Federal Financing Bank (FFB), agreed to loan GPGA 75 percent of project construction and startup costs, up to $2.02 billion. GPGA financed the rest with its own equity. Project construction was completed by December 1984 and plant startup had begun. As of July 31, 1985, GPGA had borrowed about $1.54 billion from FFB and had contributed about $493 million in equity to the project.

GPGA Defaulted on Guaranteed Loan and DOE Acquired Project

On August 1, 1985, the GPGA partnership terminated its participation in the Great Plains coal gasification project and defaulted on its DOE-guaranteed $1.54 billion loan from the FFB. In September 1985, DOE refinanced the guaranteed debt by obtaining a new loan from the Treasury at a lower interest rate and using the proceeds to retire the original loan to GPGA. DOE retired the new Treasury loan in July 1986 using funds from a supplemental appropriation. DOE's total expenditure resulting from its loan guarantee for the project, including principal and interest, was $1.64 billion.

DOE filed a petition in the federal district court in North Dakota to foreclose on the property, and the judgment was granted. The Great Plains property was formally sold to the United States of America on behalf of DOE at a foreclosure sale held on June 30, 1986. DOE's bid of $1 billion, representing a portion of the loan that DOE had guaranteed, did not involve the expenditure of any additional federal dollars. No other bids were presented.

Project Operations and Agreements

Immediately after GPGA defaulted, DOE assumed control of the project and directed the plant operator, ANG Coal Gasification Company (ANG),[2] to continue operations while DOE completed a transition plan. This arrangement continued until December 1986, when DOE and ANG entered into a new project administration agreement under which ANG continued operating the plant for DOE for a fee of about $3 million a year.

[1] The GPGA partnership includes subsidiaries of American Natural Resources Company; Tenneco, Inc.; Transco Energy Company; MidCon Corp.; and Pacific Lighting Corp.

[2] ANG, which was also a subsidiary of American Natural Resources Company, was formed to operate the project.

During the 3-1/4 years that ANG operated the plant for DOE, the plant produced an average of about 138 million cubic feet (MMcf) of synthetic natural gas per day (or about .5 MMcf per day above its design capacity rating), except for a 3-week period in July and August 1988 when the plant was shut down because of a fire. Also, project revenues exceeded project expenses by about $110.3 million.

Major operating and supply agreements have remained in force under DOE's control and ownership of the plant.

- The project's gas has been sold at above market prices to four pipeline companies under separate 25-year gas purchase agreements. The gas prices are controlled by a pricing formula contained in the agreements. A 34-mile pipeline connects the project to an interstate pipeline system that transports the gas to the four pipeline companies' systems.
- Electric power for the gasification plant has been provided under a 35-year contract between Basin Electric Power Cooperative and ANG. The power is supplied by Basin's Antelope Valley Station, which is adjacent to the plant.
- Coal has been supplied to the Great Plains project and Basin's power plant under separate 25- to 35-year contracts between ANG and Coteau Properties Company, Basin Electric, and Great Plains.
- Basin Electric and ANG have shared in using certain facilities that Basin constructed, including a water supply pipeline, railroad spur, and access road.

Great Plains Project Sold

On August 5, 1988, DOE announced at a press conference that it had selected the Basin Electric Power Cooperative of Bismarck, North Dakota, as the preferred purchaser for the Great Plains project. Basin was one of nine prospective purchasers that submitted firm offers to DOE and one of three finalists with which DOE conducted extensive negotiations. On August 25, 1988, DOE informed the Congress of its intent to enter into a binding contract for the sale of the project to Basin and provided a report on the basic sale terms and conditions. DOE stated that Basin had provided the highest offer and the strongest commitment to long-term operations.

On October 31, 1988, DOE completed the sale of the Great Plains project and related coal mine interests to two subsidiary companies that Basin established to own and operate the gasification plant and coal mine. DOE received $85 million at the sale closing and a commitment for DOE to share in future revenues from plant operations. In return, DOE transferred title to the project and mining assets to the new owners and provided $120 million for loans and cash for plant operations. The new owners took over plant and mine operations from ANG on November 1, 1988.

Objectives, Scope, and Methodology

The Department of Energy Act of 1978—Civilian Applications (Public Law 95-238) requires our office to audit recipients of loan guarantees for alternative fuel demonstration projects every 6 months and to report to the Congress on the status of the loans. In accordance with this requirement, we issued eight reports to the Congress from March 1982 through December 1985 on the status of the Great Plains project before the loan default.

After the loan default, at the request of the Chairman, Subcommittee on Energy and Power, House Committee on Energy and Commerce, we issued five reports on the status of the project's operations and financial performance. We also testified before the Subcommittee on Energy and Power and issued a report on our comparative analyses of retaining and selling the project. In addition, we issued a report analyzing DOE's valuation of Basin Electric's offer to purchase the Great Plains project. (Our reports and testimony on the Great Plains project and some of DOE's major contracted reports on the project's operations are listed at the end of this report.)

This report, which was also requested by the Subcommittee Chairman's office, provides an overview of what happened to the project under DOE's control and ownership. Chapter 2 discusses the project's operations and financial performance during the approximately 3-1/4 years that DOE owned and/or controlled the project. It also includes updated monthly gas production and financial performance data since August 1987 (the cutoff month included in our last status report on the project).[3] Chapter 3 discusses the divestiture process, congressional oversight, terms and conditions of the sale agreement, the marketing firm fee, the effect that future energy prices could have on the project's financial condition, and federal monitoring responsibilities.

In preparing this overview report, we drew upon the messages of our previous reports and testimony on the Great Plains project. The specific

[3] Synthetic Fuels: Status of the Great Plains Coal Gasification Project (GAO/RCED-88-53FS, Nov. 10, 1987).

objectives, scope, and methodology for our previous reports are contained in the respective reports. We also (1) obtained updated project operating information through October 31, 1988, (2) obtained updated information on the divestiture proceedings through April 30, 1989, (3) reviewed and analyzed the terms and conditions of the sale agreement, (4) analyzed the marketing fee, (5) estimated the effect of future energy price projections on project finances, and (6) obtained information on federal monitoring responsibilities.

We interviewed project officials and federal and state officials involved in or affected by the project. We also obtained and reviewed contracts, reports, project sale documents, and other pertinent materials from DOE, Basin and its subsidiaries, ANG, and Shearson Lehman Hutton, Inc., which assisted DOE in marketing the project. We spoke with officials at DOE's headquarters and Chicago Operations Office, the North Dakota State Department of Health, ANG, and Shearson Lehman Hutton, Inc.

We conducted our work from November 1988 through April 1989 and in accordance with generally accepted government auditing standards. We discussed the factual information in this report with DOE officials, and on the basis of these discussions, we made clarifications where appropriate. However, as requested, we did not obtain official agency comments on a draft of this report.

Project Performed Well Under DOE's Control

During the 3-1/4 years that the Great Plains project was under DOE's control, the plant was a technical success, generally producing synthetic gas at a rate exceeding its design capacity. However, DOE was unable to obtain an Air Pollution Control Permit to Operate from North Dakota because of high sulfur emissions from the plant. To resolve this problem, DOE set aside $30 million of project funds to modify the project to reduce sulfur emissions.

Under DOE's control, project revenues totaled about $658.3 million and exceeded project expenses, excluding plant depreciation, by about $110.3 million. About $600 million of the revenues resulted from the sale of synthetic natural gas, and the balance resulted primarily from pipeline transportation charges, by-product sales, and interest earned on cash investments. The project also collected about $26 million from GPGA for obligations that occurred before the loan default. The project's cash balance increased from $1.4 million when DOE assumed control to $137.8 million when the project was sold.

ANG's audits of Basin Electric Power Cooperative's charges to the project for electricity and shared facilities resulted in Basin refunding the project about $1.3 million. Three annual audits of the project's financial statements by Arthur Andersen & Company generally disclosed no audit exceptions.

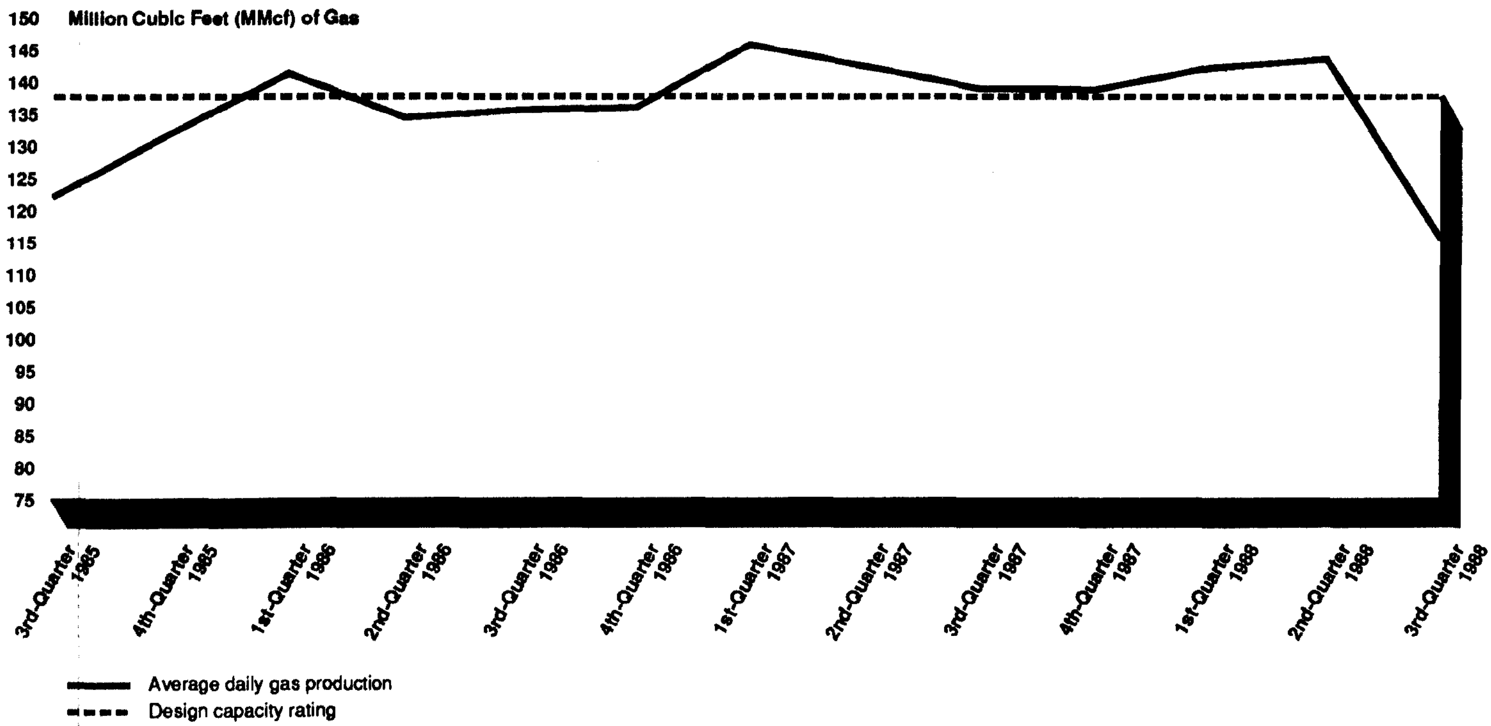
Two court challenges were resolved in DOE's favor—the U.S. Supreme Court upheld DOE's foreclosure on the project, and a federal circuit court ruled that the gas purchase agreements were valid.

Project Operations

Gas Production

DOE has declared the Great Plains project to be a substantial technical success. Under DOE's control, the project achieved average daily gas production of about 138 MMcf per day, except when it was shut down for 3 weeks in July and August 1988 because of a fire. Figure 2.1 shows the average daily gas production, on a quarterly calendar year basis, from August 1985 through October 1988.

Figure 2.1: Average Daily Gas Production by Quarter From August 1985 Through October 1988



Note: Data for 3rd quarter of 1985 includes August and September only.

Note: Data for 3rd quarter of 1988 includes October.

The plant's design capacity rating of 137.5 MMcf per day was first attained on a quarterly basis in early 1986. Production fell below the design capacity rating during the second quarter of 1986 when methanation train B was shut down for a scheduled catalyst replacement.[1] During the third and fourth quarters of 1986, the plant operated under a DOE-approved policy of not producing gas at levels exceeding the design capacity rating until studies could determine the plant's maximum and optimum safe operating levels.

On the basis of those studies, DOE directed ANG in February 1987 to (1) target monthly average gas production at about 145 MMcf per day and (2) limit daily gas production to 150 MMcf. After that, quarterly average

[1] The principal routine plant maintenance is to replace spent catalyst material in methanation systems downstream from the gasifiers. The plant's gasification systems are configured into two trains, A and B, allowing a portion of the plant to be shut down for the catalyst change while the rest of the plant continues to operate at or above 50 percent of production capacity.

gas production exceeded 140 MMcf per day, except for the third and fourth quarters of 1987 and the third quarter of 1988.

In August 1987, ANG completed a study to determine specific plant modifications that would eliminate certain design bottlenecks and increase production. ANG proposed increasing the plant's optimum operating level from 152.5 MMcf per day to 156 MMcf per day by implementing some of the recommendations of that study at a cost of about $9.9 million. However, because DOE was in the process of selling the project, it decided not to approve ANG's proposal.

Table 2.1 shows the average daily gas production delivered to the pipeline companies each month from September 1987 through October 1988. During that period, gas production averaged 132.6 MMcf per day, or 96.4 percent of the plant's design capacity rating.

Table 2.1: Average Daily Gas Production From September 1987 Through October 1988

	Average daily production in million cubic feet	Average percentage of design capacity rating
1987		
September	123.8[a]	90.0[a]
October	141.5	102.9
November	146.7	106.7
December	127.8[b]	92.9[b]
1988		
January	145.4	105.7
February	142.2	103.4
March	138.4	100.7
April	146.6	106.6
May	141.1	102.7
June	142.3	103.5
July	64.5[c]	46.9[c]
August	119.6[c]	86.9[c]
September	134.9	98.1
October	142.8	103.9

[a]Production dropped in September 1987 because of the scheduled replacement of the train B methanation catalyst.

[b]The train B methanation catalyst was replaced again in December 1987 because of contamination from an equipment failure.

[c]A fire in the methanation facility, on July 14, 1988, caused a complete gasification shutdown. During the 3-week shutdown, DOE decided to replace the train A methanation catalyst 2 months early and to perform other maintenance that could be accomplished only when the plant was not operating. Partial production resumed on August 3, 1988, and full production was restored a week later.

Plant Employment

As of October 31, 1988, there were 839 permanent employees and 84 contract personnel at the Great Plains project, as compared with 977 and 376, respectively, when DOE assumed control of the project. Many permanent and contract employees were released in 1985 as part of a reduction-in-force to lower operating costs after GPGA terminated its participation in the project.

Environmental Concerns

When DOE sold the project, it still had not obtained an Air Pollution Control Permit to Operate the project from the North Dakota State Department of Health because of the plant's high sulfur emissions. The project continued to operate under the authority of an Air Pollution Control Permit to Construct, which the health department had issued in 1977 to allow for construction and startup of the gasification plant. The Permit to Construct, as amended, limits the project's sulfur emissions to 1,340-pounds-per-hour, a level which was originally believed to be achievable based on project design using the Stretford sulfur recovery process. Despite adjustments made to the Stretford sulfur removal system since the plant startup, the system did not meet its design specifications and its operation was often interrupted by plugging.

In July 1986, the North Dakota State Department of Health notified ANG and DOE that the project violated emission standards set forth in the Permit to Construct. DOE formally responded to the notice of violation in June 1987, stating that DOE had established a committee to evaluate sulfur removal options and to recommend feasible courses of action.

On April 12, 1988, DOE filed the major portion of its application for an Air Pollution Control Permit to Operate with the state health department, proposing certain plant modifications that DOE believed would provide the best available control technology. DOE proposed upgrading the existing one-stage sulfur removal system to a two-stage system. DOE estimated that the two-stage system and related modifications would cost about $30 million and would yield sulfur emissions up to about 3,942-pounds-per-hour under worst case conditions. DOE also issued a press release stating that it had set aside $30 million of project funds to reduce sulfur emissions.

In June 1988, the state health department released a tentative schedule for considering the permit application and possibly granting the project a Permit to Operate by January 1989. DOE completed its permit application on July 1, 1988, by submitting a schedule for implementing the proposed plant modifications over a 3-year period and providing other supplemental information.

The National Park Service, which administers the Theodore Roosevelt National Park about 72 miles from the project, also reviewed DOE's permit application. In a May 25, 1988, letter to the state health department, the Park Service stated that the stricter liquid-fuel emissions limits should be applied to the fuel burned by the project's boilers.[2] The Environmental Protection Agency (EPA) subsequently agreed with the Park Service and stated that the plant's boilers must meet the stricter emission limit for gas and liquid boiler fuels, rather than the limit for solid boiler fuels which had been expected to apply. On June 29, 1988, the state health department told us that EPA's decision posed a major obstacle to issuing a Permit to Operate and would delay the permit. As of March 31, 1989, the permit had not been issued.

The project's operating permit for its solid waste disposal facilities, which was granted by the state health department in June 1987, gave the project 270 days to resolve problems related to the removal of water from ash waste. In response, ANG completed paving of the ash handling area by January 1988 and improved its methods for processing ash waste. According to ANG, the state health department subsequently conducted several inspections of the project's ash handling and disposal facilities with satisfactory results.

ANG requested an exemption from hazardous waste management requirements under the Resource Conservation and Recovery Act for all wastes resulting from fossil fuel combustion.[3] EPA granted the exemption in September 1987.

Financial Performance

[2]EPA Standards of Performance for New Stationary Sources (Subpart D) limit sulfur dioxide emissions from boilers to 1.2 pounds per million Btus for solid fuels and 0.8 pounds per million Btus for liquid fuels.

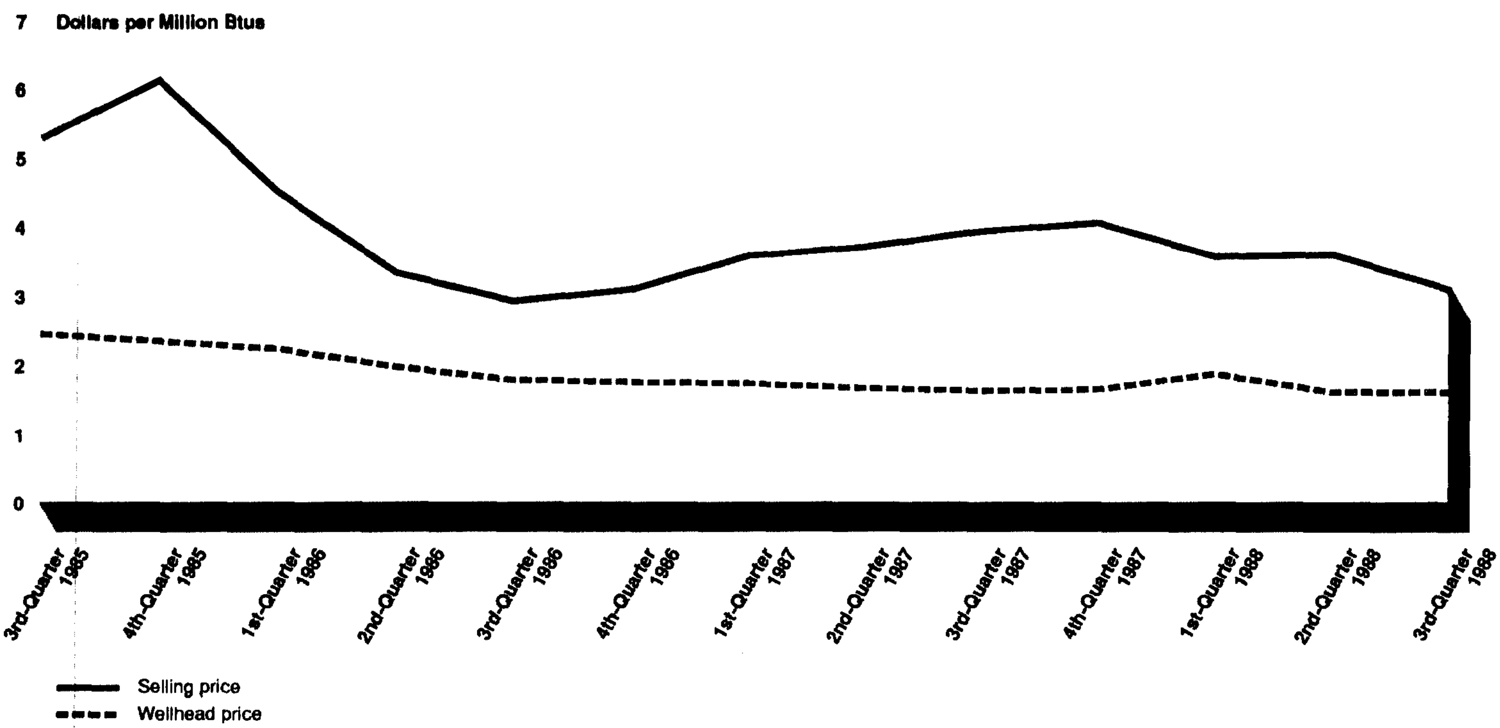
[3]40 Code of Federal Regulations 261.4(b) (4) and (7).

Gas Selling Prices

The gas the project produces is sold to four pipeline companies under separate 25-year gas purchase agreements. Under the agreements' pricing formula, gas prices cannot exceed the equivalent price of unregulated No. 2 fuel oil through June 1989, and all gas sold by the project through October 1988 was sold at that equivalent price.

Figure 2.2 compares the project's average gas selling prices with the estimated national average wellhead prices, on a quarterly calendar year basis, from August 1985 through October 1988. As a result of the gas pricing formula, the project has continued to sell its gas at rates higher than national average market prices for natural gas.

Figure 2.2: Quarterly Comparison of Average Gas Selling Prices and National Wellhead Prices



Note: Data for 3rd quarter of 1985 includes August and September only.

Note: Data for 3rd quarter of 1988 includes October.

Table 2.2 compares the project's monthly gas selling prices with operating costs from September 1987 through October 1988. Both the operating costs and the net operating costs exclude plant depreciation. Net operating costs are the remaining costs of gas production that are not offset by revenues from other sources such as pipeline transportation charges, by-product sales, and interest earned on cash investments.

Table 2.2: Comparison of Monthly Gas Selling Prices and Operating Costs

Dollars per million Btus

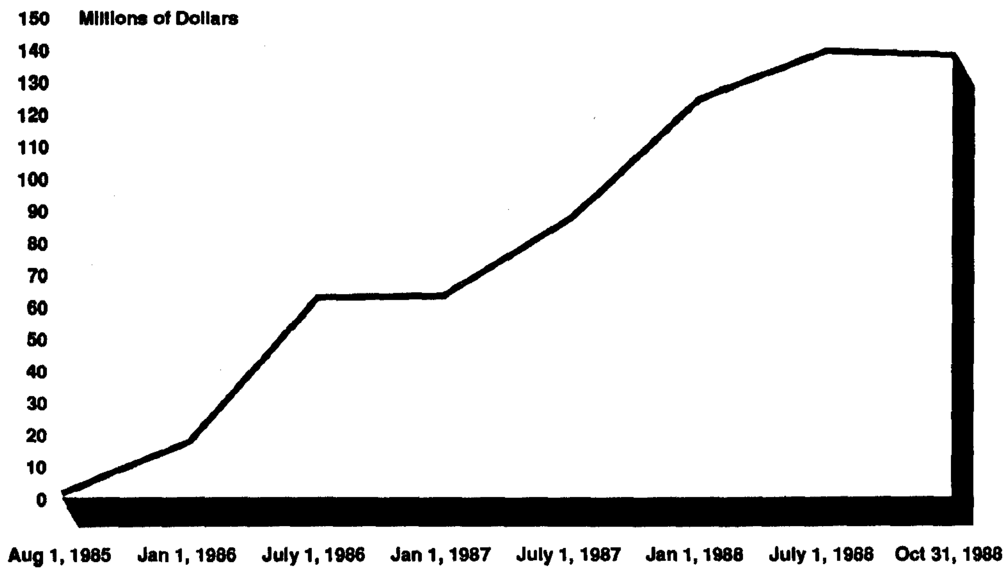
	Selling price	Operating cost	Net operating cost
1987			
September	$3.84	$4.04	$3.64
October	4.05	3.53	3.06
November	4.19	3.62	3.36
December	3.96	3.81	3.39
1988			
January	3.79	3.19	2.80
February	3.55	3.33	2.99
March	3.37	3.47	3.08
April	3.63	3.20	2.74
May	3.72	3.17	2.75
June	3.44	3.33	2.92
July	3.19	6.64[a]	5.89[a]
August	3.21	3.11	2.54
September	3.09	3.30	2.87
October	2.86	3.08	2.67

[a]The highest operating costs occurred in July 1988 when a fire in the methanation facility resulted in plant closure for 3 weeks. Lost gas production during that period, coupled with increased expenditures for repairs and additional maintenance, caused costs per unit of production to rise proportionately.

Cash Flow From Operations

Figure 2.3 shows the continued improvement in the project's cash position, on a semiannual calendar year basis, during the 3-1/4 years that the project was under DOE's control.

Figure 2.3: Semiannual Cash Balances



Cash collections other than from normal monthly receipts occurred at several points and improved the project's cash position significantly.

- In August and September 1985, the project collected initial payments, totaling $13.4 million, from GPGA for obligations incurred prior to the loan default.
- During the first half of 1986, the project collected about $40 million in past-due payments and interest on gas sales to the pipeline companies following a January 1986 federal district court decision upholding the validity of the gas purchase agreements.
- In July 1987, GPGA made a final payment of $12.5 million for obligations incurred prior to the loan default.

Table 2.3 shows the project's monthly cash flow from operations from September 1987 through October 1988. Just before the project was sold on October 31, 1988, the project had a cash balance of about $137.8 million.

Table 2.3: Great Plains Project's Cash Position

Dollars in millions

	Beginning cash balance	Receipts	Disbursements
1987			
September	$109.5	$22.1	$18.1
October	113.5	19.7	18.2
November	115.0	19.6	16.7
December	117.9	22.5	16.3
1988			
January	124.1	20.3[a]	21.6[a]
February	122.8	20.5	14.9
March	128.4	20.0	18.9
April	129.5	18.1	16.8
May	130.8[b]	20.2	17.8
June	133.2	21.4	15.5
July	139.1	19.0	16.2
August	141.9	11.7[c]	15.4
September	138.2	16.7[c]	16.7
October	138.2	17.2	17.6
Total		**$269.0**	**$240.7**
Monthly average		$19.2	$17.2

[a]Higher disbursements than receipts in January 1988 were primarily due to unscheduled maintenance expenses and annual or semiannual payments for mine equipment and insurance.

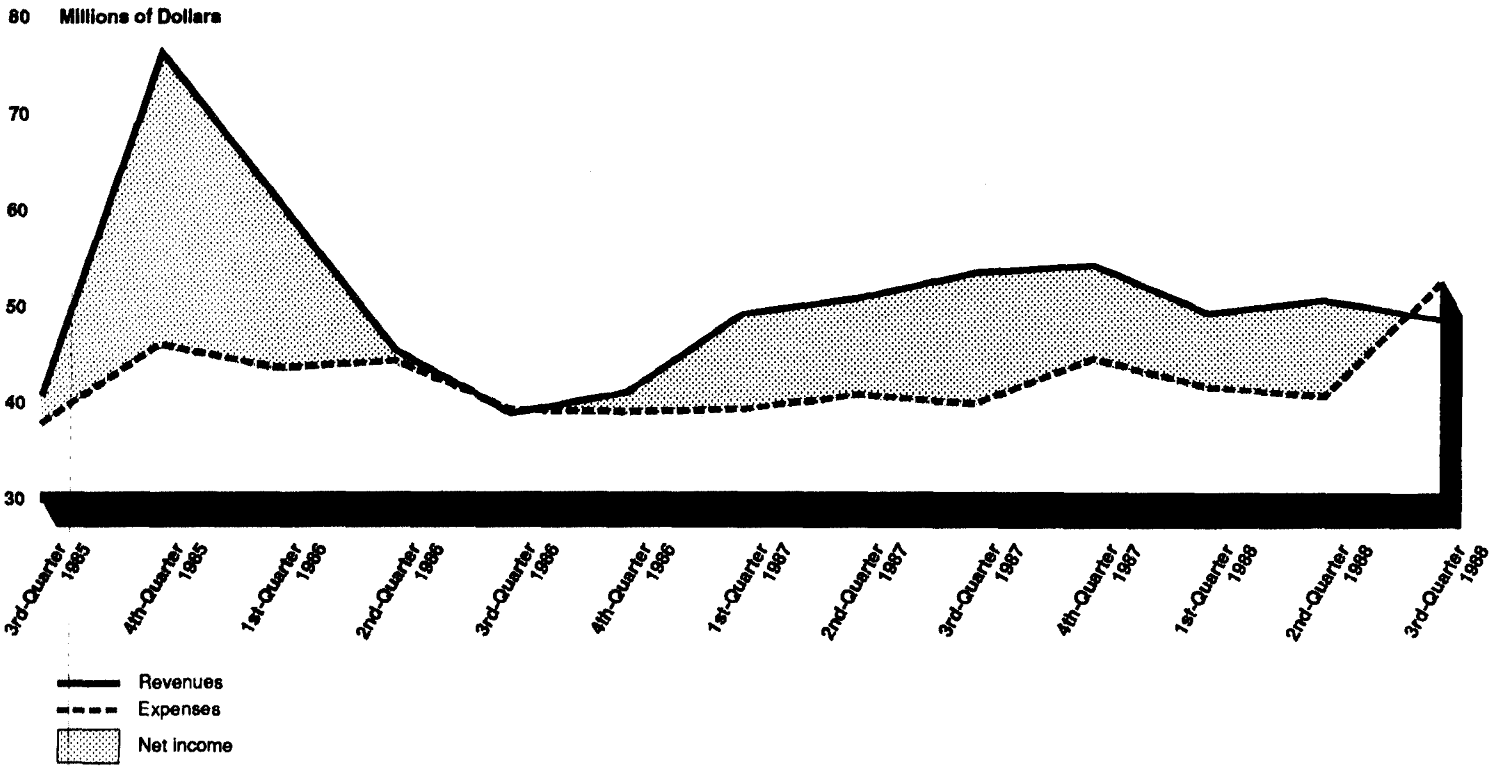
[b]Beginning in April 1988, cash balances include $30 million that DOE set aside to resolve environmental emissions problems.

[c]Lost production during July and August 1988, caused by the July 14 fire, reduced receipts during August and September 1988.

Revenues and Expenses

During the 3-1/4 years that the project was under DOE's control, project revenues totaled about $658.3 million and project expenses, excluding plant depreciation, about $548.0 million. The revenues exceeded the expenses by about $110.3 million. About 90 percent of the revenues were generated from gas sales, and about 10 percent were derived primarily from pipeline transportation charges, by-product sales, and interest earned on cash investments. Figure 2.4 shows the project's revenues, expenses, and net income, on a quarterly calendar year basis, from August 1985 through October 1988.

Figure 2.4: Quarterly Revenues and Expenses



Note: Data for 3rd quarter of 1985 includes August and September only.

Note: Data for 3rd quarter of 1988 includes October.

The high revenues and net income in the third and fourth quarters of 1985 primarily resulted from gas selling prices that exceeded $5 per million Btus. However, by the third quarter of 1986, prices had fallen to less than $3 per million Btus. Gas prices varied less after that, ranging from $3.09 per million Btus to $4.06 per million Btus, and project expenses remained relatively stable.

Table 2.4 shows the monthly revenues, expenses, and net operating income from September 1987 through October 1988. The expenses do not include project depreciation charges of about $5 million per month.

Table 2.4: Monthly Revenues, Expenses, and Net Operating Income From September 1987 Through October 1988

Dollars in millions

	Total revenues earned	Total expenses incurred	Net operating income
1987			
September	$15.1	$14.4	$0.7
October	18.9	14.8	4.1
November	18.7	15.2	3.5
December	16.6	14.5	2.1
1988			
January	18.1	13.8	4.3
February	15.4	13.2	2.2
March	15.7	14.5	1.2
April	17.3	13.5	3.8
May	17.5	13.4	4.1
June	15.8	13.7	2.1
July	7.6	12.8	(5.2)
August	13.4	11.1	2.3
September	13.7	12.9	0.8
October	13.9	15.6	(1.7)
Total	**$217.7**	**$193.4**	**$24.3**
Monthly average	$15.5	$13.8	$1.7

In November 1987, DOE acknowledged the project to be "in-service" for production purposes as of the date it took control of the project. Because lower gas transportation rates apply after the project is declared to be in-service, DOE reduced the rates the four pipeline companies pay under their gas transportation agreements. DOE also refunded a total of about $2.8 million to the pipeline companies for gas transportation overcharges from August 1985 through September 1987, including interest. ANG expected the rate change to reduce the annual revenues from gas transportation charges from $8.5 million to about $7.2 million, or by about 15 percent.

In August 1987, Arthur Andersen & Company, in conjunction with its audit of the project's financial statements, suggested that ANG begin to accrue land reclamation and postmining closing costs as coal is mined in order to establish a reserve for future liabilities associated with mine closure. In February 1988, based on estimates provided by the operator of the mine that provides the project's coal, ANG began accruing mine closing expenses of about $800,000 annually, retroactive to July 1, 1987.

Audits

In fall 1987, ANG audited Basin Electric Power Cooperative's charges for electricity supplied to the project from June 1986 through September 1987. ANG reported that about $6.7 million, or about 25 percent of those charges, were improper. On the basis of this audit and an earlier audit of Basin's charges for shared facilities, ANG claimed that the project was due substantial refunds for improper charges and that future billings should be significantly reduced. According to ANG, the total refund that Basin owed as of March 31, 1988, had grown to about $26 million, including interest, and Basin's future billings for electricity and shared facilities should be reduced by about $7.9 million annually.

DOE initially considered taking legal action against Basin to collect the amounts in dispute and consulted with the Department of Justice. However, DOE subsequently decided to negotiate a settlement directly with Basin because DOE (1) concluded that most of ANG's audit findings of improper charges lacked legal merit and would probably not be upheld by a federal court and (2) viewed the dispute as an obstacle to selling the project.

On June 1, 1988, ANG, at DOE's direction, and Basin signed an agreement settling all issues raised by both audits. The agreement was approved by the Rural Electrification Administration on August 4, 1988. On October 31, 1988, DOE accepted a refund of $1.3 million as final settlement under the agreement.

Arthur Andersen & Company conducted audits of the project's financial statements, as of June 30, 1986, 1987, and 1988. Arthur Andersen & Company's reports generally disclosed no audit exceptions.

Legal Issues

Three outstanding legal issues concerning DOE's ownership of the Great Plains project and the enforceability of the gas purchase agreements were resolved in DOE's favor.

- On July 14, 1987, the ANR Gasification Properties Company, one of the GPGA's partners, requested the U.S. Supreme Court to review the eighth circuit court's decision upholding DOE's foreclosure of the Great Plains project. On November 3, 1987, the Supreme Court refused that request, concluding litigation on this issue.
- On July 28, 1987, the eighth circuit court denied a request by three of the four pipeline companies to reconsider its denial of their appeal to overturn a federal district court's decision upholding the validity of the gas purchase agreements. The pipeline companies did not request the

Supreme Court to review the eighth circuit court's decision within the 90-day period allowed to file a request for review.

- In December 1987, Transcontinental Gas Pipe Line Corporation (Transco), one of the four pipeline companies, paid the project $373,831, which it had withheld from payments for gas delivered before the August 1, 1985, loan default. In exchange, DOE waived any claim for interest owed and accepted the $373,831 as final payment.

State and Local Taxes

During the 3-1/4 years under DOE's control, the project paid the North Dakota sales/use tax; reimbursed Coteau Properties Company, the coal mine operator, for the state coal severance tax that it paid; and reimbursed ANG, the project administrator, for the state combined/unitary income tax that it paid.

DOE also elected to make community assistance payments to Mercer County, two local municipalities, and a school district. In addition, DOE donated about 38 acres of project-owned land to the cities of Beulah and Hazen.

Divestiture of the Great Plains Project

On August 5, 1988, DOE announced that it had selected Basin Electric Power Cooperative to be the new owner of the Great Plains coal gasification project. DOE, Basin, and two subsidiary companies that Basin established to own and operate the gasification plant and coal mine signed the sale agreement on October 31, 1988. DOE's divestiture of the project took nearly 3 years and involved the marketing efforts of Shearson Lehman Hutton, Inc.; congressional oversight; and discussions with 17 prospective buyers. Further, the terms of the sale agreement are complex, and it took DOE and Dakota Gasification several months to reach agreement on purchase price adjustments.

DOE determined that Shearson was due a fee of $1.2 million for assisting in the sale of the project. However, Shearson claims that it is due a fee of $3.4 million. DOE expects Shearson to contest the fee amount before DOE's contract review board or in court.

Future energy prices will determine the amount of future revenue-sharing payments that DOE receives under the terms of the sale agreement and the amount that DOE may recover from the project cash reserve fund. Project gas revenues are based upon a pricing formula in the gas purchase agreements. Under the formula, starting at the end of July 1989, the price of natural gas will probably govern how much pipeline companies pay for the project's synthetic natural gas. If future natural gas prices drop, then project gas revenues would fall, causing DOE to lose potential revenue sharing. Also, low future project gas prices could, under certain circumstances, permit the new owner of the gasification plant to borrow from the project cash reserve fund, which would reduce the amount that DOE recovers from the fund. Further, under the terms of the sale agreement, low future project gas prices could release the new owner from its commitment to continue plant operations.

To enable DOE to monitor compliance with the sale agreement, the new plant owner is required to notify DOE of changes in plant operations and to provide DOE with financial, production, and research and development reports. DOE also has the authority to audit Basin's and its two subsidiaries' books, records and income tax returns, that relate to the sale agreement.

Marketing the Project

In February 1986, DOE placed an announcement in the Federal Register requesting any public and private sector organizations that may be interested in acquiring the plant to submit statements of interest and informational proposals. The announcement emphasized that DOE was not then soliciting specific proposals for purchasing the facility. At that time, DOE announced that its objectives were to

- transfer ownership of the plant and remove the federal government as a direct competitor in the gas production business,
- recover as much of the federal funds provided to cover the loan default as possible, and
- assure continued long-term operation of the plant to avoid disruptions to the local economy and to capture the benefits associated with the extended plant operations.

DOE received nine statements of interest in response to its Federal Register notice.

In February 1987, following a formal solicitation of proposals from investment banking-type companies, DOE awarded a contract to Shearson Lehman Brothers (which has since become Shearson Lehman Hutton, Inc.) to assist it in selling the Great Plains project. Shearson delivered its marketing plan for the project to DOE in May 1987 and distributed a descriptive memorandum outlining the major characteristics of the project to prospective buyers in October 1987.

Seventeen prospective buyers subsequently expressed interest in purchasing the project. In January and February 1988, 15 of them attended detailed technical and business briefings and toured the plant. Shearson provided a draft sale agreement to the prospective buyers and requested firm offers to be submitted by March 18, 1988. Nine companies submitted firm offers.

Reasons for Selecting Basin Electric

On August 5, 1988, DOE announced that it had selected Basin Electric Power Cooperative as the preferred purchaser for the project from among three companies with which DOE conducted extensive negotiations. The other two finalists were Coastal Corporation and Mission First Financial, a subsidiary of Southern California Edison. In announcing the selection, DOE emphasized that Basin had agreed to waive production tax credits, estimated by DOE to have a present value of about $300 million. According to DOE, Basin provided the highest offer and the strongest commitment to the project's long-term operation. DOE estimated that the net present value of Basin's offer was about $600 million.

DOE said that Coastal's offer was the best with respect to revenue sharing and return of the project's cash, but the cash Coastal offered was about equal to the net present value of the production tax credits Coastal intended to receive.

According to DOE, Mission made the best offer of cash at the sale closing, but the cash amount was less than the net present value of the production tax credits it intended to receive.

Congressional Oversight

On April 13, 1988, the Subcommittee on Energy and Power, House Committee on Energy and Commerce, held a hearing to review DOE's proposed sale of the Great Plains project. In his opening statement, the Chairman expressed concern that DOE might sell the project primarily as a tax shelter and for less than its financial value under continued federal ownership.

DOE testified that the planned divestiture would not only remove the government from the gas production business, but also return the most economic value to the nation and create a more stable future for the project. DOE said that a new owner should be allowed to benefit from production tax credits, especially since the credits would help to assure the continued operation of the plant. DOE emphasized that it would not sell the project unless it obtained a fair price but did not disclose what a fair price would be.

During the hearing, we testified on the results of our comparative analyses of retaining and selling the project.[1] We emphasized the need for DOE to consider the value of the project to the government under continued federal ownership and the effect of production tax credits in estimating a sale value for the project.

Following the hearing, we issued a report on June 10, 1988,[2] to the Chairman, Subcommittee on Energy and Power, which recommended that DOE, in determining a fair price for the Great Plains project, consider the financial value of the project under continued federal ownership and the effect of production tax credits on the federal budget. DOE implemented our recommendation by using our comparative analyses and making additional economic analyses, including an analysis of net

[1] Proposed Sale of the Great Plains Coal Gasification Project (GAO/T-RCED-88-34, Apr. 13, 1988).

[2] Synthetic Fuels: Comparative Analyses of Retaining and Selling the Great Plains Project (GAO/RCED-88-172, June 10, 1988).

cash flows under continued federal ownership. DOE used these analyses in negotiations with prospective purchasers. DOE also considered the extent to which the final three prospective purchasers would use production tax credits.

On August 25, 1988, DOE notified the Congress of its intent to enter into a binding contract for the sale of the project to Basin Electric Power Cooperative and provided a report on the basic sale terms and conditions. Public Law 100-202 (December 22, 1987) required DOE to provide this information at least 30 days before the contract became effective.

On September 12, 1988, the Senate Committee on Energy and Natural Resources held a hearing on the forthcoming sale to Basin Electric. DOE and Basin testified in support of the sale, but other groups voiced concerns. A member of ANG's board of directors, citing the lack of information about the amount of equity Basin was risking to buy the project, questioned whether Basin's commitment to continue project operations could be considered meaningful.

Another witness, who testified at the hearing on behalf of two area resource councils and as a member of one of the local electric cooperatives that comprise Basin Electric, questioned whether cooperative members were sufficiently protected from liabilities that could result from operation of the project by subsidiaries that Basin planned to establish.

On October 21, 1988, we issued a report on our analysis of DOE's estimate of the value of Basin Electric's offer to purchase the Great Plains project.[3] We stated that DOE's $600 million net present value estimate should have been reduced by about $397 million for the following reasons.

- DOE included production tax credits (with an estimated present value of about $300 million) that Basin agreed to waive. We pointed out that if a prospective buyer waives production tax credits, the buyer would make a lower sale offer adjusted for the value of the tax credits that would not be used and no further adjustment would be needed in determining the present value of the offer because there would be no increase in the revenue flow to the government.

[3] Synthetic Fuels: Analysis of DOE's Estimate of the Sale Value of the Great Plains Project (GAO/RCED-89-36, Oct. 21, 1988).

- DOE included project cash of $82 million, which consisted of $30 million that DOE expected to be returned to the government at the time of sale and $52 million representing the present value of the project cash reserve fund that DOE expected Basin to return to the government within 10 years. These funds should not have been considered as part of the value of Basin's offer because they already belonged to DOE.
- DOE did not reduce the value of the sale for the $15 million that DOE had agreed to contribute for working capital for the subsidiary that Basin planned to establish to operate the project.

These exclusions would have reduced DOE's estimate of the net present value of Basin's offer from $600 million to about $203 million.

Basin's Agreements

Basin Electric established two subsidiaries to own and operate the Great Plains project and related coal mine interests. On October 31, 1988, the Dakota Gasification Company acquired the Great Plains gasification plant and pipeline, and the Dakota Coal Company acquired the mining assets. Under the terms of the sale agreement, the two Basin subsidiaries paid DOE a total of $85 million in cash at closing, and Dakota Gasification agreed to share future revenues with DOE contingent upon future gas prices.

At the October 31, 1988, sale closing, Dakota Gasification paid DOE $15.1 million for the project's 34-mile gas pipeline, and Dakota Coal paid DOE $69.9 million for the project's mining interests, including mining agreements and equipment, and 50 percent of ANG's stock. The $85 million had been provided to the subsidiaries by Basin Electric. DOE transferred the payments to the Treasury.

In return for other project assets including real estate; plant and equipment; rights under contracts, licenses, and permits; 50 percent of ANG's stock; and $15 million working capital; Dakota Gasification agreed to make revenue-sharing payments to DOE to the extent that future gas revenues exceed production costs specified in the sale agreement, subject to certain adjustments and limitations. The specified production costs start at $3.14 per million Btus and increase to $3.96 per million Btus through the year 2009. However, after 1989 the specified production costs are to be adjusted for inflation and changes in tax and other laws and regulations that apply to plant operations, to the extent that they affect gas production costs.

If the project's gas production is reduced as a result of plant alterations to produce new by-products, revenue-sharing payments to DOE would be based on the volume of synthetic natural gas that would have been produced had the alterations not been made.

The sale agreement provides that DOE is entitled to gas revenue-sharing payments in some years, but not others, as indicated below.

- From November 1988 through December 1989 (14 months), DOE would receive 100 percent of the gas revenues that are subject to sharing.
- From January 1990 through December 1994 (5 years), DOE would not receive any revenue-sharing payments.
- From January 1995 through December 2004 (10 years), DOE would receive 100 percent of the gas revenues that are subject to sharing.
- From January 2005 through December 2009 (5 years), DOE would receive 50 percent of the gas revenues that are subject to sharing.

The sale agreement provides that revenue-sharing payments will be based on the excess of gas revenues over the adjusted production costs reduced by (1) the amount of federal, state, and local income tax liability that applies to that excess and (2) any payments Dakota Gasification makes to repay loans from the $75 million project cash reserve fund. However, payments cannot exceed $1.565 billion.

In August 1988, DOE estimated that future revenue-sharing payments would have a present value of about $113 million. In our October 21, 1988, report, we calculated the present value of future revenue-sharing payments to be about $111 million (using Wharton Econometrics' energy price forecasts) and about $205 million (using Data Resources, Incorporated's energy price forecasts). Dakota Gasification's first revenue-sharing payment is due February 1, 1990.

The sale agreement provides for two tax concessions by Basin and its subsidiaries. First, the three companies agreed to waive the right to claim production tax credits. DOE estimated that the present value to the government of this waiver was about $300 million. Second, Dakota Gasification agreed not to claim tax benefits related to revenue-sharing payments before the tax year in which the payments are actually made to DOE.

Dakota Gasification agreed to continue operating the project and to try to maintain average annual gas production of at least 142 MMcf per day until

- the gas purchase agreements expire or are terminated;
- the cumulative plant operating expenditures exceed the cumulative funds generated from project operations, plus all funds available from the project trust, Basin's revolving credit agreement, and other sources; or
- a disqualifying event occurs, which Basin and its subsidiaries could not have prevented, and which renders the project permanently inoperative.

Basin agreed to provide $30 million to Dakota Gasification in revolving credit to help ensure the project's long-term operation through 2009. Dakota Gasification agreed to borrow only to the extent necessary to operate the project. With few exceptions, Basin's two subsidiaries agreed to assume all of DOE's obligations and liabilities in connection with the project.

DOE's Agreements

In addition to the other project assets that DOE provided to the Dakota Gasification and Dakota Coal companies, DOE also provided $120 million for cash and loans to Dakota Gasification from the project's $137.8 million cash balance at the sale closing. DOE established a project trust of $105 million and provided $15 million in working capital for project operations. The trust consisted of two funds—a project cash reserve fund of $75 million and an environmental fund of $30 million.

The $75 million project cash reserve fund is to provide loans to Dakota Gasification for project operations. Interest on such loans is to be computed based on prevailing rates for 1-year Treasury bills, plus 2.75 percent. Until December 31, 2009, Dakota Gasification is obligated to repay loans from the project trust only to the extent that future gas selling prices exceed specified production costs, as adjusted under the sale agreement.

For the first 6 years, through December 1994, Dakota Gasification can borrow up to $75 million from the trust if gas revenues fall below the adjusted production costs as a result of a drop in the price of No. 2 fuel oil, or if any of the four pipeline companies that purchase the gas does not make required payments under its gas purchase agreement. Depending on the trust balance, DOE may recover up to $50 million of the $75 million, plus interest, at the end of the 6-year period.

For the next 4 years, from January 1995 through December 1998, Dakota Gasification can borrow up to $25 million if gas revenues fall below the adjusted production costs because of declines in the price of imported or domestic natural gas for any reason, or if any of the four gas purchase companies fails to make required payments. DOE may recover all funds remaining in the project cash reserve fund on or after January 1, 1999.

The sale agreement also permits DOE to make loans to Dakota Gasification during the 10-year period through December 1998 at DOE's discretion. All outstanding loans from the project trust are due and payable on December 31, 2009. However, DOE may declare them due and payable earlier if Dakota Gasification files for bankruptcy, either Basin or Dakota Gasification breaches its obligations under the sale agreement, or project operations are discontinued for at least 6 months.

DOE provided $30 million to Dakota Gasification for future plant modifications to resolve environmental problems and enable Dakota Gasification to obtain an Air Pollution Control Permit to Operate the project. Under terms of the sale agreement, up to $1.5 million became available to Dakota Gasification after October 31, 1988. The remaining $28.5 million will be available for Dakota Gasification to pay or reimburse its documented costs related to plant modifications, provided Dakota Gasification

- obtains the North Dakota State Department of Health's approval for plant modifications needed to obtain a Permit to Operate;
- develops a plan for implementing those plant modifications, including cost estimates; and
- consults with DOE about the plan.

The environmental fund will be liquidated and any remaining balance will be paid to DOE when the $30 million is disbursed or a Permit to Operate is obtained, but not later than December 31, 1995. DOE also contributed $15 million to Dakota Gasification for working capital for project operations. DOE will not recover any of that cash.

In April 1988, DOE directed ANG to deposit about $4 million in a trust account to meet a state requirement for a collateral bond to ensure reclamation of the mine that supplies the project's coal. At the sale closing, DOE waived its right to recover the reclamation bond balance, which had increased to about $4.6 million. DOE also agreed to make all revenues and benefits under the gas purchase agreements available to Dakota Gasification, if the assignment of the agreements to the company is contested. In addition, DOE agreed to provide funds for

- paying any refunds claimed for gas transportation fees from October 28, 1987, through the sale closing date, to the extent that DOE approves such refunds;
- settling ANG discrimination suits not resolved as of the closing; and
- paying severance benefits for up to 85 ANG employees.

DOE also transferred any rights it may have to inventions made or conceived during construction or operation of the project but identified after closing.

Disposition of Assets and Liabilities

On October 31, 1988, just prior to closing, the project had current assets of about $173.3 million and current liabilities of about $15.7 million, according to financial statements audited by Arthur Andersen & Company. Current assets included cash of about $137.8 million.

At closing, DOE disposed of the project's $137.8 million cash as follows.

Table 3.1: Disposition of the Project's Cash on October 31, 1988

Dollars in thousands		
Cash on hand prior to closing		$137,846
Disbursed at closing:		
To the Great Plains project trust		
Environmental fund	$30,000	
Project cash reserve fund	75,000	
To Dakota Gasification		
For working capital	15,000	
Total disbursements at closing		**120,000**
Cash on hand after closing		$17,846

In order to have a central account from which to disburse funds owed and deposit funds received after closing, DOE established a Great Plains liquidating trust account at a Bismarck, North Dakota, bank and transferred all of the project's cash to that account.

The balance of the liquidating trust account on March 31, 1989, was about $19,299,000. The balance reflected additional receipts of about $2,257,000, of which about $1,319,000 was collected from Basin in settlement of a dispute with ANG over Basin's charges to the project for electricity and shared facilities. It also reflected disbursements of about $804,000 for payment of ANG's October 1988 project administration fee;

the final community impact assistance to the city of Beulah; audit, legal, and bank fees; and other expenses. DOE planned to retain about $10 million of the liquidating trust account funds until all liabilities pertaining to its operation of the project were settled.

Under the sale agreement, Dakota Gasification essentially agreed to pay DOE a purchase price adjustment equal to the excess of the value of the project's current assets over its current liabilities (excluding cash and inventories) as of the October 31, 1988, sale closing. On the basis of financial statements audited by Arthur Andersen & Company, DOE and Dakota Gasification determined that the excess of current assets over current liabilities was about $5.3 million. However, on April 14, 1989, Dakota Gasification paid DOE a purchase price adjustment of only $2.7 million for the following reasons.

- Under the sale terms, DOE agreed to reimburse Dakota Gasification and Dakota Coal for severance benefits they paid, as required by law or ANG policy, up to the first 85 ANG employees who (1) were terminated by ANG and did not accept employment with one of the companies, or (2) accepted employment with one of the companies but were terminated before April 30, 1989. According to DOE, Dakota Gasification paid severance benefits for 78 ANG employees, at a cost of about $1.5 million, and recovered its costs by reducing the purchase price adjustment.
- In 1987, DOE authorized ANG to spend $1.5 million to study the technical and economic feasibility of developing additional by-products. DOE later increased the total authorization to $1.6 million. In September 1988, because many of the study's objectives had not been met, DOE agreed to pay Dakota Gasification for further work on the study, through January 1989, as long as the total expenditures (both before and after the sale) did not exceed the $1.6 million authorized. Before the sale closing, about $883,000 of the authorized funds had been spent or committed. According to DOE, Dakota Gasification spent all of the remaining money (about $732,000) that DOE had agreed to pay for further work on the study and recovered its costs by reducing the purchase price adjustment.
- The purchase price adjustment was further reduced by about $400,000 to reflect adjustments in valuing current assets and liabilities.

Dakota Gasification transferred the $2.7 million purchase price adjustment payment to DOE's liquidating trust account. DOE later paid Dakota Gasification about $90,000 for severance benefits for eight additional former ANG employees. According to DOE, only one issue remains unsettled. The Department of Labor determined that certain project employees who worked 12-hour shifts had been underpaid for a 2-year period, and DOE believes it may be liable for up to $260,000 of back pay, pending the Department of Labor's determination of the amount due.

Agreements Not in DOE's Congressional Report

Public Law 100-202 required DOE to report the terms of the project's sale to the Congress at least 30 days before the sale contract became effective. On August 25, 1988, DOE submitted a report that described the principal terms of the tentative sale agreement with Basin Electric's subsidiaries. However, the final sale terms included several agreements that were not in the August report. They included (1) the possible loss of future federal income taxes, (2) Dakota Gasification's agreement to pay DOE the difference in the value of the project's current assets and liabilities, (3) DOE's concession of the $4.6 million mine reclamation bond balance, (4) DOE's agreement to pay severance benefits of about $1.5 million for ANG employees, and (5) DOE's agreement to reimburse Dakota Gasification up to about $732,000 for further work on the uncompleted by-product study.

As previously discussed, the purchase price adjustment was based on the excess adjusted value of the project's current assets over its current liabilities reduced by Dakota Gasification's costs for severance payments and additional by-product study work. Also, the possible loss of future federal income taxes may be offset by additional revenue-sharing payments, as discussed below. Therefore, the combined effect of these developments reduced the value of the sale to the government by about $1.9 million (the difference between the $2.7 million purchase price adjustment payment and the $4.6 million mine reclamation bond balance concession).

Payment of Future Federal Income Taxes

In its August 25, 1988, report to the Congress, DOE attributed $20 million of the net present value of Basin's purchase offer to future tax revenues, but DOE has more recently acknowledged the possibility that federal income taxes may not be paid on Dakota Gasification's profits from the project.

DOE said that Basin Electric is a taxable entity that pays no federal income taxes by structuring its electricity rates to members in such a way as to assure that taxable revenues always equal tax-deductible expenses, so it has no taxable income. Because DOE (1) anticipated that Basin might seek to avoid paying federal income tax on Dakota Gasification's profits by reducing members' electricity rates proportionately and

(2) viewed those taxes as an integral part of the value to the government from the sale, DOE sought to include a special provision in the sale agreement to ensure that federal income taxes on Dakota Gasification's profits would be paid separately.

According to DOE, however, it was advised by its tax law firm in September 1988 that Dakota Gasification is required by law to file a consolidated federal income tax return with Basin and that DOE could not prevent it. On the basis of that advice, DOE abandoned its efforts to include the special provision in the sale agreement. The final sale agreement indicates that Dakota Gasification will file a consolidated income tax return with the affiliated group of corporations of which Dakota Gasification and Basin are members. DOE said that the possibility now exists that federal income taxes will not be paid on Dakota Gasification's profits, but it is too soon to know for sure. However, because the sale agreement provides that revenue-sharing payments are to be reduced for applicable federal income taxes, DOE expects that future federal income tax losses to the government will generally be offset by gains in revenue-sharing payments.

Mine Reclamation Bond Balance

During the final sale negotiations, DOE agreed to waive its right to recover any of the $4.6-million mine reclamation bond balance as a final negotiating concession. According to DOE officials, it would have been difficult for DOE to recover the funds because they reverted to ANG when the project was sold and ANG stock was included in the sale.

Marketing Firm Fee

Under the terms of DOE's February 1987 contract with Shearson Lehman Hutton, Inc., DOE was to pay Shearson $100,000 per quarter for assisting with the sale of the project over a period not to exceed six quarters. Also, if the project were sold, Shearson was to receive as its fee 1 percent of the first $50 million of the selling price as defined in the contract, one-half percent of the next $450 million, and three-eighths percent of the remainder of the selling price, less the amount of quarterly payments received.

DOE paid Shearson a total of $1.2 million, which included $600,000 that had been provided to Shearson as of the sale closing. DOE calculated the fee by applying the fee formula to the sum of the cash that DOE received at the sale closing and the present value of estimated future revenue-sharing payments.

Shearson contends that the basis for calculating the fee should also include the present value of the production tax credits that Basin and its subsidiaries waived their right to use and the cash that DOE deposited in the project's trust fund at the sale closing. In addition, Shearson contends that the present value of future revenue-sharing payments should be at least $42 million higher than DOE estimated. Shearson informed DOE that on the basis of its calculation, its fee should be $3.4 million, rather than $1.2 million. DOE expects Shearson to contest the amount of its fee before DOE's contract review board or in court.

In our October 21, 1988, report on the sale value, we concluded that neither production tax credits nor project cash should be included in calculating the value of the sale to the government. DOE excluded these items in calculating Shearson's fee.

Effect of Future Energy Prices on Sale Terms

The project's future synthetic natural gas prices will affect revenue-sharing payments to the government, the use of the $75 million cash reserve fund, and Dakota Gasification's commitment to continue project operations.

Prices are set by terms of the gas purchase agreements under which all of the project's gas is sold to four pipeline companies. Under those agreements, the project's gas price is essentially set at the equivalent price of No. 2 fuel oil through July 1989. Then, for the next 5 years (through July 1994), the price of the project's gas sold to each company will essentially be set at

- the greater of (1) the average price the pipeline company pays for the highest 10 percent of natural gas bought from domestic sources or (2) the average price the company pays for natural gas imported from Canada and Mexico; but
- the price may not exceed the equivalent price of No. 2 fuel oil.

After July 1994, the price of No. 2 fuel oil will no longer be a factor. From August 1994 through 2009, if domestic gas prices are unregulated, the project's gas price will be set by the average price each pipeline company pays for the highest 10 percent of natural gas bought from domestic sources. However, if domestic prices are regulated, the current average quarterly price of natural gas that each company imports from Canada and Mexico will govern.

To develop its estimate of the value of Basin's purchase offer, DOE used energy price forecasts prepared by the Energy Information Administration (EIA). For our October 21, 1988, report analyzing DOE's valuation, we used Wharton Econometrics' and Data Resources, Incorporated's (DRI) energy price forecasts.

Revenue-Sharing Payments

For DOE to earn revenue-sharing payments, the price of the project's synthetic natural gas must be greater than the contract production costs specified in the sale agreement, and the revenues must be earned during a period when DOE is eligible for a share of the revenues.

Both DOE's analysis using EIA's energy price forecasts and our analysis using Wharton's and DRI's energy price forecasts indicated that DOE would earn revenue sharing for the first several months following the sale. However, our analysis also indicated that for 1989 DOE would not earn any revenue sharing after July, when the price of the project's gas may no longer be determined by the equivalent price of No. 2 fuel oil.

Under terms of the sale agreement, DOE is not eligible for revenue sharing from January 1990 through December 1994. However, for the 10-year period beginning January 1, 1995, DOE can earn all gas revenues that exceed the predetermined production costs specified in the sale agreement.

- Under DOE's analysis (using EIA's energy price forecasts), gas revenues would actually begin to exceed predetermined contract production costs in 1997, or 2 years after the revenue-sharing provision is reactivated.
- Under our analysis, gas revenues would actually begin to exceed predetermined contract production costs in 1999 (using Wharton's energy price forecasts) and 1998 (using DRI's forecasts), or 4 years and 3 years, respectively, after the revenue-sharing provision is reactivated.

Project Cash Reserve Fund

As previously mentioned, during the first 6 years (through 1994) Dakota Gasification can borrow up to $75 million from the project cash reserve fund if (1) gas revenues fall below the predetermined contract production costs as a result of a drop in the price of No. 2 fuel oil or (2) any of the gas purchasers fail to pay amounts due under its gas purchase agreement.

Both Wharton's and DRI's energy price forecasts indicated that the price of No. 2 fuel oil would substantially exceed natural gas prices through

1994, even after natural gas prices are adjusted, in Shearson's economic model, for the highest 10-percent domestic gas price factor and the imported gas price factor. If these energy price forecasts hold true, the price of No. 2 fuel oil would not affect the price of the project's gas. Consequently, Dakota Gasification would not be able to borrow from the fund, through 1994, as long as the four pipeline companies continued to honor the gas purchase agreements.

DOE may recover up to $50 million of the fund, plus interest, at the end of 1994. DOE estimated that on the basis of its risk assessment, it would recover about $44 million (88 percent) of the $50 million, plus interest, at that time.

From 1995 through 1998, Dakota Gasification can borrow up to $25 million from the project cash reserve fund if gas revenues fall below the predetermined contract production costs for any reason. DOE estimated that on the basis of its energy price forecasts and risk assessment, it would recover about $8 million (32 percent) of the $25 million, plus interest, at the end of this 4-year period.

Commitment to Continue Project Operations

Dakota Gasification would be allowed to discontinue operating the project if the company's cumulative expenditures for operations exceed the cumulative funds generated by project operations, or is otherwise available to the company from all sources, including the project cash reserve fund and Basin's revolving credit agreement.

Using Wharton's and DRI's energy price forecasts and the financial computer model that Shearson prepared for DOE, we estimated how long Dakota Gasification would continue to have a positive cash balance. We assumed that Dakota Gasification would not be able to borrow from the project cash reserve fund for at least 6 years but that it would use up the $30 million in revolving credit from Basin and the $15 million of working capital from DOE. Our analysis indicated that Dakota Gasification would run out of cash in 1991 using Wharton's energy price forecasts and in 1992 using DRI's forecasts. DOE's own analysis using EIA's data, on which DOE based its valuation of Basin's offer, indicated that Dakota Gasification would run out of cash in 1994. However, Basin and DOE stated that continued long-term operation of the project would be in Basin's best interest and that closure of the plant could cost Basin about $37 million annually in net revenues from the sale of electricity to the project.

DOE Monitoring Responsibilities

The terms of the agreement under which the project was sold to Basin Electric's subsidiaries involve DOE monitoring responsibilities. The sale agreement requires that DOE must be provided certain reports and other notifications to enable DOE to ensure that Basin and its subsidiaries comply with the terms of the sale agreement.

Both Dakota Gasification and Dakota Coal must provide monthly financial statements to DOE, and Dakota Gasification must provide copies of billings for synthetic natural gas delivered to the interstate pipeline. Each company must also provide annual certified financial statements. In addition, Dakota Gasification must provide annual reports on gas production and research and development of alternative energy technologies and by-products.

Each loan that Dakota Gasification obtains from the project cash reserve fund must be accompanied by a statement from the company's certified public accountant assuring that specific conditions of the sale agreement have been met. Also, once a year Dakota Gasification must provide DOE with a statement by its public accounting firm confirming that the amount of revenue-sharing payments the company made for the prior year is correct, and a statement that neither Dakota Gasification, Basin, Dakota Coal Company, nor any affiliated group of corporations received any benefit from the production tax credit during the prior year. If Dakota Gasification changes its public accounting firm, DOE has the right to approve the replacement.

The North Dakota bank that is the trustee for the $105 million Great Plains project trust is required to provide monthly reports to DOE and Dakota Gasification showing (1) disbursements from the environmental fund, (2) loans from the cash reserve fund, (3) investment earnings, (4) payments of principal and interest on loans. The trustee must also notify DOE if a loan repayment by Dakota Gasification is late.

Terms of the sale agreement require that DOE be notified or consulted before certain actions can take place. For example,

- Dakota Gasification must consult with DOE about any planned plant modifications before it can draw more than $1.5 million from the $30 million environmental fund that was established to solve environmental problems.
- Dakota Gasification must provide DOE with at least 60 days advance notice of its intent to discontinue project operations and allow DOE an

opportunity to meet with Basin, Dakota Coal, and its own company before ceasing operations.

- Dakota Gasification may not undertake plant modifications to produce new by-products until it has obtained DOE's agreement concerning the amount of reduced gas production that will result from the modifications.

DOE is entitled to audit the books, records, and income tax returns of Dakota Gasification, Dakota Coal, and Basin Electric Power Cooperative that relate to compliance with the sale agreement.

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Related GAO Products

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