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CROW TRIBE OF INDIANS. SYNFUELS FEASIBILITY STUDY

Volume 1. Executive Summary

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ABSTRACT

This study presents the feasibility of using the abundant natural coal resources of the Crow Tribe of Indians to produce and sell substitute natural gas (SNG) from their Montana reservation. Four cases of an SNG production capacity of 125 million standard cubic foot per calendar day (expandable to 250 MMSCF/CD) are analyzed as to coal supply, coal transportation, raw water supply, solid waste disposal and site selection and preparation. All cases use the proven Lurgi coal gasification technology. An SNG and byproduct market analysis is made and a cost-of-service for the cases is determined. Environmental impact, health and safety requirements, socioeconomic aspects, and legal constraints are examined and discussed. The financial opportunities and risks offered potential energy investors are weighted heavily by current economic conditions and a soft fuels market. The project is technically and environmentally feasible. The uncertainty of energy markets and supply, however, makes it impossible to make the financial commitment required to move the project forward at this time. Therefore, it is recommended that the project be delayed indefinately. In addition, there are a number of steps identified that the Crow must take to attract equity investors if the project is to proceed at some future date.

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VOLUME I

EXECUTIVE SUMMARY

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1.0 INTRODUCTION

In April, 1980 the Crow Tribe of Indians (CROW) submitted a proposal in response to the Department of Energy's Solicitation for Feasibility Studies for Alternate Fuels Production (DE-PA01-80RA50185). The project proposed by the Crow was a synfuels plant designed to produce 125 MMSCF per calendar day of substitute pipeline quality natural gas (SNG) with a capability of being expanded to 250 MMSCF per calendar day. The synfuels facility would be located on the Crow Reservation in Montana and would utilize coal and water resources owned by the Crow.

In September 1981, Grant No. DE-FG01-81RA50351 was issued funding the 10-month study. Assisting the Crow on the study were the following:

> The Council of Energy Resources Tribes (CERT), agent for the Crow: Pacific Coal Gasification Company (Pacific), project manager; Fluor Engineers and Constructors, Inc. (Fluor), designer; Lehman Brothers Kuhn Loeb, Inc. (Lehman), financial consultant.

The overall objective of the study has been to provide the necessary technical, economic and environmental data to arrive at a decision on the project viability. To accomplish this objective, the following tasks were performed:

(1) The process was selected based on proven commercial technology and a preliminary design of the plant was completed;

(2) Coal and water requirements were established and the most economical sources defined;

(3) Alternate sites for the facility were evaluated and the optimum site for each coal supply was identified;

(4) The capital and operating costs of the project were estimated and the cost of proceeding with the project was determined;

(5) The economic and financial feasibility of the project was assessed;

(6) The market for various products and byproducts was analyzed;

(7) The impact of the project on the environment was assessed and facility design and monitoring methods were developed to safeguard against any adverse impacts;

(8) The socioeconomic impact of the project was analyzed and an information dissemination program initiated on the Reservation and surrounding area;

(9) An overall project management plan for proceeding to the next phase was developed including a master schedule reflecting permitting, engineering, procurement and construction requirements.

Several design alternatives were assessed in the study. These included evaluation of two coal sources, plant siting options, coal fines utilization and coproduction of SNG and methanol. To assess these options four cases were developed. These are defined in the report as follows:

(1) Base Case - In this case 18,000 short tons of coal per stream day (ST/SD) are fed to the synfuels facility to produce 137.5 MMSCF/SD along with 405 MW of electric power of which 283 MW are exported for sale. Coal for the Base Case is from Westmoreland Resources, Inc.'s, operating Absaloka mine. Coal fines which can not be fed to the gasifiers are assumed to represent 40 percent of the coal feed and are fed to the boilers.

(2) Self-sufficiency Case - This case is identical to the Base Case except no electric power is exported for sale. This results in an excess of coal fines which are assumed to be marketed elsewhere.

(3) Coproduction Case - This case is identical to the Base Case except that 67.35 MMSCF/SD of SNG and 3752 ST/SD of methanol are produced. Export power for this case is 212 MW.

(4) Shell Coal Case - This case feeds 17,600 short tons of coal per stream day to the synfuels facility to produce 137.5 MMSCF/SD along with 423 MW of electric power of which 302 MW are exported for sale. Coal is from Shell Oil Company's proposed Youngs Creek mine.

The Feasibility Study Final Report is organized into five volumes. Volume I, Executive Summary, presents the conclusions and recommendations of the study, a summary of each of the other volumes and the management plan for implementing the design and construction of the project. The master schedule for the project is included in the management plant.

Volume II, Process Design and Cost Estimate, is a three book volume. The three books include the design, capital costs and operating costs for each of the four cases. In each case the overall plant description, feed and product summary, thermal efficiency, design basis, plant unit list, plant train philosophy, overall plot plan, overall material balance, plant water balance, sulfur balance, air emissions diagram, solid effluent diagram, steam balance, utility summary, catalysts and chemicals summary, and operating and maintenance manpower requirements are presented. In addition, for the Base Case, engineering data is presented for each plant process, utility and offsite unit. Included are a material balance, process flow sketch, plot plan and equipment list for each unit. For the other three cases, engineering data is presented only for the units that differ from the

Base Case. Capital and operating costs for each of the four cases are presented following the technical analyses and serves as the bases for the economic analyses presented in Volume III, Part A.

Volume III includes the financial analysis in Part A and the legal analysis in Part B. Part A addresses the financing of the Crow coal resource for use in several types of projects including a proposed financial structure for the synfuels project to proceed; presents the available federal financial assistance available to the project; presents a proposed financial structure for the synfuels project, and then utilizing the capital and operating cost data from Volume II, a economic analysis is presented for each of the four cases. The end result is a cost-of-service for producing SNG in the facility along with sensitivity analyses of the pertinent parameters and a risk analysis of the project. Part B of Volume III is a legal analysis of the project. The study presents pertinent aspects of environmental, regulatory, water and Indian law relative to the synfuels project.

Volume IV is a two book volume. Book I (Part A) presents the environmental assessment of the project, and Book II (Parts B and C) incorporates the health and safety assessment and the socioeconomics assessment for the project.

Volume V includes the special studies performed as part of the feasibility study. Included are separate studies on coal supply, coal transportation, solid waste disposal, raw water supply, site analyses, product and byproduct marketing and transportation analyses and the planning and communication analysis.

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2.0 CONCLUSION AND RECOMMENDATIONS

2.1 CONCLUSIONS

The following conclusions are made based upon the results of the feasibility study.

2.1.1 Development of Resources

The Crow Tribe of Indians have abundant natural wealth. Much of this in the form of coal. To obtain significant Tribal income from this coal, the Crow must look to the development of energy projects of Crow Tribal lands which would use this coal.

2.1.2 Market Analysis

The market for the substitute natural gas (SNG) product considered for this study is the southern California area. However, the SNG must be competitively priced for the market to exist. Southern California is anticipated to have an unsatisfied demand for natural gas in the 1988-1995 period. The Crow SNG plant could possibly satisfy 22 percent of that demand with the 125 MMSCF/CD plant and 57 percent of the unmet demand with the later expanded 250 MMSCF/CD plant, but the SNG would compete with other new supply sources for market share. Cost of constructing pipeline facilities for transporting the SNG and operating costs of the pipeline system impact the cost of service significantly. Revenue can be increased by sale of byproducts. A market exists for ammonia and export power. There appears to be a market for naphtha, but the sulfur market is difficult to assess. A strong market for methanol could develop in the 1990's and enhance coproduction of SNG and methanol. It should be noted that for the purposes of the study only the southern California area was considered for SNG sales. While this market is large, conservation and fuel switching could reduce it considerably.

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2.1.3 Financial

(1) The cost of service for SNG (1982 dollars) for all cases ranges from six dollars to seven dollars at the plant gate. This results in a delivered price of the SNG into the southern California market considerably higher than the market clearing price for alternative fuels.

(2) The economics and risks of the synfuels project are such that the project needs both loan guarantees and price guarantees from the Synthetic Fuels Corporation (SFC) in order to be viable. The project cannot produce SNG competitively at today's prices and thus needs price guarantees. The loan guarantees are required to reduce the completion risk in the construction phase. The price guarantee is necessary to insure marketability of the SNG during the operating period. After construction, price guarantees would assure a specified minimum price level.

(3) The Crow Synfuels Project is projected to cost $3.15 billion in construction costs plus capitalized interest of $518 million. The total financing requirement of $3.66 billion includes an allowance for inflation.

The manner in which SFC financial assistance is now available will make it difficult to accomplish a project of the size contemplated in this study. A smaller project might be feasible within the limits of the available Government financial assistance. This would require additional study. The maximum total financial liability of the SFC to a single project is $3 billion. This would include any past payments to the project. This $3 billion limit includes awards made in the form of a single incentive type or more than one type of incentive such as a loan guarantee and a price guarantee provided to the same project. The $3 billion limit could be subject to change at anytime.

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The major risks for financial sponsors of the project which were identified are:

a. Project abandonment prior to commencement of operations due to cost overruns, technical failure, environmental regulations or any other reasons;

b. Delays in reaching design capacity and cost overruns.

c. Higher than anticipated operating costs, particularly feedstock costs and maintenance costs;

d. More restrictive environmental requirements with accompanying higher capital and operating costs;

e. The failure of the plant to meet designed output capacity;

f. Technical obsolescence at some point in the future;

g. Technology failure;

h. Uncontrollable major events including strikes, etc.;

i. Higher than anticipated financial costs;

j. Unavailability of a market for the project output;

k. Lower than anticipated product prices; and

l. Changes in tax laws.

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These risks are present under any project financial structure. An example of the differences in risk taking that is available from Government loan guarantees, as opposed to price guarantees only, is that a non-recourse loan guarantee to the project typically results in the Government taking the majority of the risks in all categories listed. Under a price guarantee, the Government takes only a part of the marketability risk. It should also be recognized that the future demand for synfuels is very sensitive to worldwide political and socioeconomic events. However, these negative factors must be balanced by the fact that the Crow Tribal Lands and the control of the Crow Tribe over land, coal, and water make this one of the most attractive potential sites for a major synthetic fuels project.

2.1.4 Plant Design and Cost Estimate

(1) The process design for the SNG plant is based on proven commercial technology--the Lurgi coal gasification technology. In addition to the coal gasification units, Lurgi technology is used for gas cleanup, liquid by-product processing, methanol synthesis, and methanation. Other proven licensor technology form the balance of the plant. Utility and offsite units are similar to conventional refinery systems.

Although capital costs were lower for the Base Case (Westmoreland Coal) than for the Shell Coal Case (Shell Coal), net operating costs were lower for the Shell Coal Case as well as the resulting cost-of-service. The Power Self-sufficiency Case had the lowest capital costs of all cases considered, but also the lowest byproduct credits which resulted in the highest cost-of-service. The Coproduction Case (SNG-Methanol) had the highest capital and operating costs of all cases considered which indicates that the methanol would have to be sold at a premium above the cost of SNG to obtain the same return on equity to the investor.

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(2) Coal Feed - Composition of Shell coal is slightly better (lower ash content, lower sulfur content, and higher calorific value) than Westmoreland coal, but costs more.

(3) Coal Transportation - The lowest cost for shipping Shell Coal was to Site 20 (Site 23 would be minemouth for Shell Coal); the lowest cost for Westmoreland is shipping to Site 1. However, the higher cost of Shell coal at the mine offsets the transportation costs incurred with the Westmoreland coal.

(4) Solid Waste Disposal - The solid wastes are not considered hazardous. Wastes from Shell coal (minemouth) cost more (operating cost) to dispose than does the operating cost of the waste disposal facility at Site 1 for Westmoreland coal.

(5) Raw Water Supply - Both capital and operating costs favor the Big Horn River as the water source for Site 1. The Yellowtail Dam is the cost effective source for Site 23.

(6) Site Assessment - Site 1 had the lowest overall cost-of-service based on parameters studied. Site 1 had lowest cost in every area except coal transportation. The minemouth advantage of Site 23 is offset by higher costs for coal, water supply station, access road and site preparation.

(7) Product and Byproduct - The Power Self-sufficiency Case is the most efficient because of reduction in power production. It has significantly lower capital requirements and lower operating costs than the other three cases. This is offset with much lower byproduct credit since there is no power for export and the problem of unused excess coal fines. The production of methanol in the Coproduction Case reduces the production of SNG and power. The Base Case and Coproduction Case have similar capital and operating costs. The Shell Coal Case produces more naphtha, ammonia, and power, less sulfur at greater capital and operating costs.

2.1.5 Legal

There appears to be no insurmountable legal obstacles to the project. Careful planning may well avoid protracted disputes regarding legal jurisdiction. Unity in commitment to this project by the Crow Tribe is important legally and financially.

2.1.6 Environmental

Proper planning is essential to avoid confusion, delay, duplication of effort, and inefficiencies in acquiring the required environmental permits. The Crow have an advantage in permitting because of their unique self-rule authority. There are no apparent unsolvable environmental problems.

2.1.7 Health and Safety

Health and safety protection is assured through engineered controls in the plant, through work practices, through personal protective equipment and clothing, and through--most important--special procedures and training. The plant can be designed to present no adverse health or safety hazard to plant personnel or surrounding community.

2.2 RECOMMENDATIONS

Because of the currently existing softness in the world energy markets, it does not seem appropriate to continue this project at the present time. However, the Crow Tribe should be sensitive to worldwide political and socioeconomic changes that may later affect that conclusion.

2.2.1 Financial

(1) It is recommended that the Crow Tribe take certain necessary steps to make this project more attractive should the world energy situation change to make the project feasible. These steps are: (a) establish the legal framework for negotiating, approving and signing agreements which cannot be reversed by subsequent unilateral Crow Tribe action and allowing the Crow Tribe to be sued under these agreements; (b) establish a legal mechanism where the Tribe agrees not to impose any subsequent tax on the project; and (c) establish the manner in which the Tribe would be willing to participate in the project.

The Crow Tribe would also need to provide assurance to investors. The SFC can only guarantee up to 75 percent of the project costs. The balance of the funds, estimated to be on the order of $900 million, must be provided by private participants (equity investors). In constructing and operating a project on Crow Tribal land, potential investors and lenders to the project will insist that the economics of the project and the ability to proceed with the project will not be altered by arbitrary actions of the Crow Tribe.

(2) The project can be organized as a corporation, a partnership or a joint venture. A corporation is not a recommended form of organization given that no sponsor will own the 80 percent share required to file a consolidated tax return and hence take the project's tax benefits when they are available. A partnership could be appropriate for the project if, by virtue of the tax status of participants or the changing role of participant, there is a need to enter into a formal partnership agreement. Under this structure, the partners would be 80 to 100 percent owned subsidiaries of the project sponsors. However, at present there is no need for a partnership structure. The typical form of a project of this nature is a joint venture of the participants.

Under this joint venture, a subsidiary corporation of each of the sponsors would typically be the venturer. The obligation of each of the sponsors would be set forth in an operating agreement which would appoint one sponsor as the project operator. This agreement would provide for sharing of expenses, allocations of production or revenues, assumptions of the obligations of a defaulting partner, and a voting method for major project decisions and changes. The existence of this operating agreement is one measure of project maturity under the SFC evaluation process and so this becomes an important recommendation for the synfuels project.

2.2.2 Plant Design and Cost Estimate

(1) The capacity of the SNG plant is recommended to be 125 MMSCF/CD with potential capacity expansion to 250 MMSCF/CD. Although this particular project may not be funded readily under the Government loan guarantee and price guarantee program, the Crow Tribe has one of the premier sites for a synfuels project.

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2.2.2 (Continued)

(2) A smaller project could be accomplished under the existing Government program. A preliminary investigation performed during the feasibility study indicated that a minemouth location at the Westmoreland Absaloka mine would be possible if the plant size were limited to 125 MMSCF/CD, there were no export power generated, and the excess fines were exported for sale. Other process modifications and reduced operating costs indicate the potential for considerable cost savings resulting in lower cost-of-service. This option should be investigated in more detail in the next phase.

Management Plan

When the project is released, it is recommended that it proceed on a phased approach under an organizational arrangement as proposed in the Management Plant presented in Section 4 of this volume. Work should be performed under the direction of a Managing Contractor using a task force concept.

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3.0 SUMMARY

3.1 PLANT DESIGN AND COST ESTIMATE SUMMARY

The primary objective of the Crow Tribe of Indians Synfuels Feasibility Study is to determine the cost of service for producing SNG from coal on the Crow Reservation. In Volume II, the capital and operating costs for the synfuels facility are developed. These values become the basis for the cost of service development in Volume III, Financial and Legal Analysis.

To determine the optimum location, coal supply, and process design required the investigation of various special studies and process configurations. This part of the study describes the results of the four process design cases which were considered in evaluating the capital and operating costs for the synfuels facility. The special studies presented in Volume V analyze the impact of the coal supply and the site.

The synfuels feasibility study evaluates four process design cases: a Base Case and three alternate cases.

The Base Case is a coal-to-SNG plant, based on Westmoreland Resources, Inc. coal generating export power and located at Site 1. The Self-sufficiency Case assumes that electric power is generated only for inplant use (no export power). The site, coal source, and SNG product are identical to the Base Case. The Coproduction Case varies the process design to coproduce SNG and methanol. Other parameters are identical to the Base Case. The Shell Coal Case is based on producing the same amount of SNG as the Base Case, but uses Shell coal and Site 23 as the basis for the design. Export power is also generated.

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3.1.1 Design Considerations

Several design considerations apply to all of the cases.

The facility is designed to produce 125 MM SCF/CD of SNG in the Base Case. Additionally, the facility is designed to be expandable to twice this size at a later date. Coal reserves, water supply, plot area and location are adequate to accommodate a 250 MM SCF/CD facility with power generation for export.

In each case the plant uses the best available control technology to protect the local environment. Particulate matter and sulfur oxides are removed from flue gases; coal dust is contained within closed conveying and storage systems.

Environmental constraints imposed by the nearby Northern Cheyenne Indian Reservation, which has an EPA designated Class I air emissions control requirement, necessitate the location of the synfuels plant away from the Westmoreland mine for the coal supply producing 250 MM SCF/CD and export power. Air emissions modeling indicates that a single 125 MM SCF/CD plant without generating export power could be located at the minemouth. This would result in considerable capital savings and should be evaluated during the next project phase.

The plant is designed to achieve zero water discharge. Only in wetting of the solid wastes to aid in their handling and through evaporation does any water leave the plant. No deep disposal wells are required to inject waste water. All ponds are lined to eliminate percolation loss.

Solid wastes, depending on the case, are disposed of either in the mine or adjacent to the plant on a virgin site. The wastes are disposed in a clay-lined subsurface containment. The encapsulation prevents the wastes from being subject to leaching by surface water runoff. Monitoring wells will measure subsurface activity and provide early warning to the potential of contaminating water aquifers.

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3.1.2 Base Case

The process technology is described in detail for the Base Case, but much is common to all of the cases.

The process design is based on Lurgi coal gasification technology which has been proven in commercial installations. The largest Lurgi type operating plants are in South Africa. The Great Plains Project in North Dakota, which is very similar in design to the proposed Crow Synfuels plant, is being constructed at the present time using lurgi design.

In addition to coal gasification, Lurgi technology is used for gas cleanup, liquid byproduct processing, methanol synthesis, and methanation. The selective Rectisol process removes carbon dioxide and sulfur compounds from the cooled gasifier product gas and condenses naphtha. Rectisol produces an H_2S-rich gas stream which is suitable for Claus sulfur recovery. Air emissions modeling show that the Rectisol CO_2-rich gas stream can not be directly vented to the atmosphere because of the hydrocarbon content. Instead, the gas makes up a portion of the fuel used in the process steam superheater. Lurgi liquid byproduct processing consists of: gas liquor separation, tar distillation, naphtha hydrotreating, and phenosolvan. The methanol used in the Rectisol unit is produced by the Lurgi methanol synthesis process which has been used in commercial installations to produce methanol from natural gas. The Great Plains Project will demonstrate the Lurgi methanation process on a commercial scale.

Other licenser technologies are used in the plant. Ammonia is recovered from the gas liquor by the U.S. Steel Phosam-W process. The Sulfur Recovery Unit incorporates the Shell ADIP and Scot processes, the Claus process and the Peabody-Holmes Stretford process. The Texaco Partial Oxidation process produces additional "raw" synthesis gas from phenols,

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3.1.2 (Continued)

oils and tars. Hydrogen production uses the Union Carbide Pressure Swing Absorption process, and oxygen production uses proven technology. Davy-McKee provided a package with preliminary technical information for their Saarberg-Hoelter flue gas desulfurization process.

The utility and offsite units are similar to conventional refinery systems designed by Fluor.

3.1.3 Comparisons

The following sections depict the various parameters that were evaluated and the resulting comparisons.

3.1.3.1 Coal Feed Comparison

Coal analyses for the four cases are presented in Table 3.1.3-1, and coal feeds for the four cases are presented in Table 3.1.3-2. The first three cases are based on coal from Westmoreland's operating Absaloka mine and the fourth case is based on coal from Shell's proposed Youngs Creek mine.

The price per ton of delivered coal for the Power Self-sufficiency Case does not allow for disposal of the excess fines. A substantial cost could be incurred if no market is available for the excess fines.

The coal analyses data reflect three items which favor the Shell coal -- lower ash content, lower sulfur content and higher calorific value. The latter is the most significant because it results in 4 percent less coal required for the Shell coal to produce the same gas product. This is

TABLE 3.1.3-1

COAL ANALYSIS

(As Received)

	Base Case @ Site 1	Self-Sufficiency Case @ Site 1	Coproduction Case @ Site 1	Shell Coal Case @ Site 23
Moisture, wt.%	26.0	26.0	26.0	26.3
Ash, wt.%	7.4	7.4	7.4	4.1
Volatile Matter, wt.%	26.5	26.5	26.5	32.5
Fixed Carbon, wt.%	40.1	40.1	40.1	37.1
TOTAL	100%	100%	100%	100%
HHV, Btu/lb	8612	8612	8612	9090
Sulfur, wt.%	0.82	0.82	0.82	0.38

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TABLE 3.1.3-2
COAL FEED COMPARISON

	Base Case @ Site 1	Self-Sufficiency Case @ Site 1	Coproduction Case @ Site 1	Shell Coal Case @ Site 23
Coal Quantity, MM Tons/yr	5.976	4.380	5.976	5.843
Coal Cost at Mine, $/Ton	10.70	10.70	10.70	-
Coal Cost at Plant, $/Ton	14.75	14.75	14.75	15.85
Annual Coal Cost, $ Million	88.1	64.6	88.1	92.6

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3.1.3.1 (Continued)

depicted in Table 3.1.3-2. The lower ash quantity reduces solid waste disposal costs, and the lower sulfur percentage reduces overall sulfur emissions; however, the latter two do not significantly impact the overall economics.

Even though less coal is required for the Shell Coal Case, the Shell coal is more expensive at the mine. The higher cost at the mine more than offsets the transportation costs associated with the other cases which use Westmoreland coal.

Water for the project is supplied from the Bighorn River. Although water requirements vary between winter and summer conditions, approximately 10,000 acre-feet are required per year for the 125 MM SCF/CD facility. The pipeline for transporting the water to the facility is sized for the expanded case (250 MM SCF/CD).

3.1.3.2 Product and Byproduct Summary

The products and byproducts for the four cases are presented in Table 3.1.3-3. They reflect the methanol production in the Coproduction Case versus only SNG as in the three other cases. The quantity of products and byproducts from the Coproduction Case indicate a reduction in power export of 41 MW. The energy equivalent of the coproduced SNG and methanol versus the SNG in the Base Case is 5815 million Btu per hour versus 5615 million Btu per hour respectively. Naphtha production is considerably less for the Coproduction Case. The reduction in naphtha results because less tar oil is upgraded with the elimination of the CO shift unit in the Coproduction Case. The increase in naphtha production in the Shell Coal Case is a characteristic of the coal.

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3.1.3.2 (Continued)

The efficiency for the Coproduction Case is lower than for the Base Case. The efficiencies are comparable for the Base Case and the Shell Coal Case. The reduction in power production raises the efficiency considerably for the Self-sufficiency Case.

3.1.3.3 Capital Cost Summary

The capital costs are based on a combination of capacity factoring, machinery and equipment factoring, and detailed estimating techniques. Each unit is priced on a Direct Field Cost basis for each case. Overall costs are summarized in Table 3.1.3-4.

This table summarizes the capital costs for each case exclusive of financing costs and interest during construction (IDC). The Base Case reflects a 3 percent lower capital cost than the Shell Coal Case. The increased Shell Coal Case capital costs reflect the additional water pipeline, access roads and site preparation costs required for Site 23. Also, increased capital costs result because of additional power generating facilities for the Shell Coal Case. Because the Shell Coal has a higher heating value, less coal is required to supply the inplant energy consumption, therefore a corresponding greater power export results.

Comparing the Base Case and the Power Self-sufficiency Case, the capital cost difference is $364.9 million to produce an additional 283.2 MW of power. This is $1288/kW which is comparable to the installed cost for new coal fired power generating facilities.

For the Coproduction Case, the capital costs are very similar to those of the Base Case.

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TABLE 3.1.3-3

PRODUCT AND BYPRODUCT COMPARISON

	Base Case @ Site 1	Self-Sufficiency Case @ Site 1	Coproduction Case @ Site 1	Shell Coal Case @ Site 23
SNG, MM SCF/SD	137.5	137.5	67.35	137.5
Naphtha, ST/D	196.2	196.2	116.8	352.6
Ammonia, ST/D	76.8	76.8	76.7	90.3
Sulfur, ST/D	87.2	87.2	86.7	39.9
Methanol, ST/D	0	0	3752	0
Electricity, MW	283.2	0	212.3	301.7
Overall Efficiency, %	54.2	63.9	52.8	55.0

TABLE 3.1.3-4

CAPITAL COST SUMMARY

(1st Quarter 1982 Dollars)

	Base Case @ Site 1 ($ Million)	Self-Sufficiency Case @ Site 1 ($ Million)	Coproduction Case @ Site 1 ($ Million)	Shell Coal Case @ Site 23 ($ Million)
Direct Field Costs	884.4	711.2	888.2	921.3
Material Transport Costs	70.0	56.0	70.6	74.0
Indirect Field Costs	351.6	289.1	348.2	352.7
Home Office Costs	160.0	132.2	170.0	165.0
Total Field and Office Costs	1 466.0	1 188.5	1 477.0	1 513.0
Other Capital Costs	570.4	483.0	570.7	580.9
Total Capital Costs[1]	2 036.4	1 671.5	2 047.7	2 093.9

(1) Does not include financing costs and interest during construction (IDC); see Section 3.2 for financial analysis.

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3.1.3.3 (Continued)

In summarizing the capital cost analysis, the Self-sufficiency Case represents a significantly lower capital requirement than the other three cases. However, it does not result in any export power, and it does not consume all of the coal fines that are generated in the coal preparation. The Coproduction Case is only slightly more costly than the Base Case and produces slightly more product on a Btu basis but produces less byproduct in the form of power and naphtha. The Shell Coal Case has a higher capital cost than the Base Case because of the longer water pipeline and access roads and the higher site preparation costs due to the rougher topography at Site 23.

3.1.3.4 <u>Operation Cost Summary</u>

The operating costs for the four cases are presented in Table 3.1.3.-5. Review of the operating costs shows the highest operating costs for the Shell Coal Case primarily because of the higher coal costs and higher water pumping costs associated with the longer water pipeline for Site 23. The Self-sufficiency Case is a simpler plant requiring fewer operating personnel and less overall maintenance labor and materials. The Base Case and Coproduction Case are very similar in operating costs.

To evaluate the net operating costs for the four cases, a comparison of the byproduct revenues is analyzed. Table 3.1.3-6 summarizes the expected annual revenues for each case. Examining the byproduct credits, the Shell Coal Case has the highest value because of the greater quantity of naphtha and export power produced. The Self-sufficiency Case byproduct value is much less than the other cases because there is no export power credit. The Coproduction Case is lower than the Base Case reflecting the reduction of naphtha and power export.

TABLE 3.1.3-5

OPERATING COST SUMMARY

(1st Quarter 1982 Dollars)

	Base Case @ Site 1 ($ Million)	Self-Sufficiency Case @ Site 1 ($ Million)	Coproduction Case @ Site 1 ($ Million)	Shell Coal Case @ Site 23 ($ Million)
Coal Cost	88.1	64.6	88.1	92.6
Catalysts and Chemicals	13.6	11.0	11.0	12.8
Plant Management Staff	1.6	1.6	1.6	1.6
Operating Labor and Materials	16.0	15.1	16.4	16.0
Maintenance Labor and Materials	36.1	28.8	36.3	36.4
Electricity	0.5	0.3	0.5	2.5
Ash Disposal	2.2	1.5	2.2	2.1
Taxes and Insurance	37.0	29.7	37.2	38.5
Annual Operating Costs	195.1	152.6	193.3	202.5
Byproduct Credits	(115.2)	(25.1)	(83.5)	(135.3)
Net Annual Operating Costs	79.9	127.5	109.8	67.2

Note: Operating costs for 1989 are assumed to be 67 percent of the above values.

TABLE 3.1.3-6

ANNUAL BYPRODUCT REVENUES

(1st Quarter 1982 Dollars)

	Base Case @ Site 1 ($ Million)	Self-Sufficiency Case @ Site 1 ($ Million)	Coproduction Case @ Site 1 ($ Million)	Shell Coal Case @ Site 23 ($ Million)
Naphtha, $268/ST	17.4	17.4	10.4	31.4
Ammonia, $235/ST	6.0	6.0	6.0	7.0
Sulfur, $60/ST	1.7	1.7	1.6	0.8
Electricity, 4¢/kWh	90.1	0	65.5	96.1
Total	115.2	25.1	83.5	135.3

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3.1.3.6 (Continued)

The results of combining the annual operating costs with the byproduct credits for the four cases studied are summarized in Table 3.1.3-5. The lowest net annual operating costs are reflected in the Shell Coal Case. A discounted cash flow analysis is necessary for each of the four cases studied to determine which case has the lowest cost of service. The discounted cash flow analyses along with various sensitivity analyses are presented in Volume III, Financial and Legal Analysis and is also summarized in Section 3.2 of this volume.

Additional information required to perform the economic evaluations as well as to provide a portion of the basis of design is presented in Table 3.1.3-7. It presents the production schedule and onstream factor for each of the cases. Also required, the cash disbursement schedules are presented in Table 3.1.3-8. The cash flow corresponds to the project master schedule included in the Management Plan of Volume I, Executive Summary.

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TABLE 3.1.3-7

PRODUCT PRODUCTION SCHEDULE

	Base Case Self-Sufficiency Case Shell Coal Case	Coproduction Case
First Gas into Pipeline	1/1/89	1/1/89
First Methanol to Sales	-	1/1/89
Full Production	7/1/89	7/1/89
1989 SNG Production (1)	30,688	14,973
1989 Methanol Production (3), (4)	-	834,000
1990 - 2013 SNG Production Per year	45,625	22,348
1990 - 2013 Methanol Production (3), (4) per year	-	1,250,000
2014 SNG Production (1)	22,813	11,174
2014 Methanol Production (3), (4)	-	622,000
SNG Heating Value (2)	980	980
Onstream Factor	332	332
Plant Production, per stream day (1)	137.5	67.3
per calendar day (1)	125	61.2

NOTE:

1. Gas Production in MM SCF (Million Standard Cubic Feet)
2. SNG Heating Value in Btu/SCF (British thermal units per standard cubic foot)
3. Methanol production in short tons (short ton is 2000 lb.)
4. Methanol heating value - 9740 Btu/lb

TABLE 3.1.3-8

CASH FLOW SCHEDULE

(1st Quarter 1982 Dollars)

	Base Case @ Site 1 ($ Million)	Self-Sufficiency Case @ Site 1 ($ Million)	Coproduction Case @ Site 1 ($ Million)	Shell Coal Case @ Site 23 ($ Million)
4th Quarter 1982	1.7	1.5	1.8	1.8
1st Quarter 1983	2.6	2.3	2.7	2.7
2nd Quarter 1983	3.1	2.7	3.2	3.1
3rd Quarter 1983	5.0	4.3	5.2	5.1
4th Quarter 1983	6.8	5.9	7.1	6.9
1st Quarter 1984	8.3	7.2	8.7	8.5
2nd Quarter 1984	9.0	7.7	9.4	9.2
3rd Quarter 1984	9.5	8.0	9.9	9.7
4th Quarter 1984	9.7	8.2	10.0	9.9
1st Quarter 1985	10.8	9.5	11.4	11.0
2nd Quarter 1985	12.4	11.0	13.1	12.6
3rd Quarter 1985	12.9	11.4	13.6	13.1
4th Quarter 1985	39.3	33.1	40.3	40.2
1st Quarter 1986	66.9	55.7	68.3	69.2
2nd Quarter 1986	99.8	82.3	101.2	103.4
3rd Quarter 1986	131.1	107.1	132.5	135.7
4th Quarter 1986	156.0	128.0	157.4	161.2
1st Quarter 1987	182.3	149.2	183.4	188.2
2nd Quarter 1987	200.4	164.0	201.1	206.5
3rd Quarter 1987	204.8	167.7	205.2	210.8
4th Quarter 1987	191.8	157.2	191.8	197.0
1st Quarter 1988	184.1	151.2	183.7	188.6
2nd Quarter 1988	171.1	139.8	170.7	175.3
3rd Quarter 1988	136.5	110.7	136.1	139.5
4th Quarter 1988	106.4	85.8	106.0	108.7
1st Quarter 1989	68.7	55.2	68.5	70.4
2nd Quarter 1989	5.4	4.2	5.4	5.6
Total	2,036.4	1,671.5	2,047.7	2,093.9

3.2 FINANCIAL ANALYSIS

3.2.1 Introduction

The Crow Tribe of Indians (Crow) has abundant natural resources wealth. Much of this is in the form of coal. The Crow have leased some of the coal reserves to Westmoreland Coal Company and Shell Oil Company in exchange for royalty income received when coal is sold. Softness in world energy markets and reduced consumption of electrical power has led to surplus coal capacity in western regions of the U.S. As a result, the demand for coal from these leases is soft and coal sales to outside parties are likely to remain at low levels for a long period into the future.

In order to obtain significant Tribal income from sales of coal, the Crow look to the development of energy projects on the Crow Tribal lands which would use this coal. To explore the uses for Crow coal, the Crow Tribe has conducted two feasibility studies, the first, which has been completed prior to this report, was for an electric powerplant project to be built on the Crow Tribal lands. The major focus of this second report is on the likely financial structure and financial results under this structure of a major synfuels project on Crow land.

3.2.2 Financing a Major Energy Development Project

While the Crow Tribe has wealth in the form of natural resources, unless the Crow could sell some of these resources, capital necessary for resource development must come from outside sources. The Crow, for example, cannot borrow funds against their coal reserves. The reserves alone do not provide a stream of cash to the Crow Tribe with sufficient certainty that a lender would be assured that the debt will be repaid.

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3.2.2 (Continued)

The Crow must therefore obtain the capital necessary for resource development from outside parties. This capital must be, in part, in the form of equity or risk capital which will be invested by private parties seeking a return on the capital.

To effectively deal with potential investors who will provide the financial resources to develop coal resources, the Crow must understand the available feasible financial structures, potential returns to both investors and the Crow Tribe and what risks must be borne by potential investors. Understanding these factors, which an investor will study in determining whether or not to invest, defines the latitude which the Crow Tribe has in negotiating successfully to accomplish such a project.

3.2.2.1 General Financing Considerations

There are two general approaches to financing a major project of the type anticipated in the case of either the electric power plant or the synfuels project. The first approach is where the project sponsors raise capital on their own account and provide that capital to construct and operate the project. In the second approach, the project itself is used as the basis for raising some of the project's capital requirements. In this case, which is called "Project Financing", funds are borrowed against the project's ability to meet debt payments.

In project financing, the project, including specific project assets, and not the general credit of a corporation, serves as the collateral for the loan. In this case the project would typically be financed with a mixture of debt and equity funds. The focus of this study is on project financing of the synfuels project.

3.2.2.2 Synfuels Project

Although a number of financial structures are possible for the synfuels project, the most feasible is one where the U.S. Synthetic Fuels Corporation (SFC) provides loan guarantees and price guarantees to the project. Under a Government guarantee, lenders will look to the Government, and not to the project, in the event that the project cannot meet repayment of interest and principal. The Government in turn, under these circumstances, will foreclose on its collateral, the project itself. Project sponsors can therefore achieve true project financing with a SFC guarantee.

Under the Synthetic Fuels Corporation enabling legislation, the SFC can only guarantee up to 75 percent of the project costs. The balance of the funds estimated to be on the order of $750 million must be provided by private participants.

The private participant would normally provide funds in the form of equity. To make this project attractive to potential equity investors, the SFC would need to structure a transaction which provides sufficient return with limited risk to the equity investor. The Crow Tribe would also need to provide sufficient comfort to investors that the project, as it might be proposed to the SFC, will be permitted to proceed as planned.

3.2.3 Requirements for Proceeding With the Project

To accomplish a major energy project, the financial activities can be divided into four major time phases. In the first phase, the potential project sponsors study the financial and economic feasibility of the project. Once feasibility is determined and the sponsors decide to proceed, the second phase includes establishing the management organization of the project, identification of sponsors, identifying lenders and obtaining

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3.2.3 (Continued)

financial commitments. This can proceed in tandem with detailed engineering and refining the cost estimates. During the second phase, the sponsors begin to order equipment with long lead times for procurement. In the third phase, construction and startup take place with the activities of the project monitored to anticipate cost overruns and delays. In the final phase the project commences operations and generates revenues.

As the project passes through each phase, the financial requirements increase. For the synfuels project, at the first phase the sponsors will spend \$5 to \$15 million. At the second phase, before construction is started, at least \$50 to \$100 million will be spent. To complete design and construct the project a total of approximately \$3 billion will be spent. The requirements for funds to be spent in this manner is a major obstacle for the project. The sponsors must spend in excess of \$50 million before they know with any certainty what the project will cost. Before the \$50 million is spent the sponsors will insist that they have clear rights to the project site and the relationship with the Crow Tribe is fixed. This means that all approvals and agreements will have negotiated with the Crow Tribe in a manner such that the approvals and agreements cannot be reversed.

3.2.3.1 Obtaining Equity Sponsors

In constructing and operating a project on Crow Tribe land, potential investors and lenders to the project will insist that the economics of the project and the ability to proceed with the project will not be altered by actions of the Crow Tribe, subsequent to the commencement of the second phase of activities previously outlined. The details of accomplishing this are addressed in the legal study. However, to be successful in attracting a group of equity investors, the Crow Tribe must address the actions which the Tribe needs to take to make this project attractive to potential project sponsors at the end of this feasibility study.

3.2.3.1 (Continued)

The Crow Tribe needs to take the necessary steps in advance of negotiating with potential sponsors. These consists of: (1) establishing the legal framework for negotiating, approving and signing agreements which cannot be reversed by subsequent unilateral Crow Tribe action and allowing the Crow Tribe to be sued under these agreements; (2) establishing a legal mechanism where the Tribe agrees not to impose any subsequent tax on the project; and (3) establishing the manner in which the Tribe would be willing to participate in the project.

3.2.4 Available Federal Financial Assistance For Synthetic Fuels

The economics of the synfuels project are such that the project requires financial assistance from the SFC. The maximum total financial liability of the SFC to a single project at any point in time is $3 billion. This would include any past payments to the project. This $3 billion limit includes awards made in the form of a single incentive type or more than one type of incentive such as a loan guarantee and a price guarantee provided to the same project.

This study anticipates that the project will request two forms of financial assistance: loan guarantees to finance construction and product price guarantees following startup. The loan guarantees are required to reduce the completion and performance risks in the project during the construction phase and to supplement the price guarantee during the operating period. Subsequent to construction, price guarantees assure a specified minimum price level.

The SFC has the authority to guarantee 100 percent of the principal of loans approved by the SFC. Such guarantees cannot exceed 75 percent of the initial estimated cost of the project. The SFC also has the authority to finance cost overruns beyond the amount of the total project cost specified in providing the initial award, but at a decreasing percentage of the amount of the overrun.

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3.2.4 (Continued)

The SFC is also authorized to enter into price guarantees. The law requires that price guarantees cannot be based on a cost-plus arrangement or any variation thereof which guarantees a profit to the project. The law specifically excludes a cost of service tariff from the definition of cost-plus types of loan guarantees. SFC is also required, in awarding price guarantee contracts, to establish a specified sales price at the level which would provide the minimum subsidy determined by SFC to be necessary to provide adequate incentive for the project.

3.2.5 Crow Synfuels Project Financial Structure

The project organizational structure options are principally determined by the tax benefits of the project. If the project is financed on a non-recourse basis with a government guarantee, the interest deductability contributes to the tax benefits without liability for the debt appearing on the firms financial statements.

The tax benefits under the project are the 10 percent Investment Tax Credit, interest deductions during construction (if the project is leveraged) and accelerated depreciation deductions during operations. Most of the project's assets would be "5 year property" under the recently enacted tax law changes.

The 10 percent Energy Tax Credit is only available if by January 1, 1983: (1) all engineering studies were completed in connection with construction and (2) the project has applied for all environmental and construction permits also by January 1, 1983 and (3) before January 1, 1986 the project has entered into binding contracts for the acquisition, construction or erection of equipment specially designed for the project and the aggregate cost of that equipment is at least 50 percent of the cost for all such project equipment. The synfuels project cannot meet this timetable.

3.2.5 (Continued)

The project can be organized as a corporation, partnership or a joint venture. The typical form of a project of this nature is a joint venture of the participants. Under this joint venture, a subsidary corporation of each of the sponsors would be set forth in an operating agreement which would appoint one sponsor as the project operator. This agreement would provide for sharing of expenses, allocations of production or revenues, assumptions of the obligations of a defaulting partner and a voting method for making major project decisions and changes. The existence of this operating agreement is one measure of project maturity under the SFC evaluation process.

3.2.6 Financial Characteristics of the Project

3.2.6.1 Project Costs

The project capital cost for each of the cases studied are shown in Section 3.1, Table 3.1.3-4. Operating costs and the timing of capital investment are shown in Tables 3.1.3-5 and 3.1.3-8. These costs are expressed in 1982 dollars and are escalated for the financial evaluation to determine actual dollars to be spent. In the case where the project is financed through loan guarantees, the project costs will reflect these capital costs plus interest during construction.

The four cases examined are divided into two sets. The first cases examine projects with substitute natural gas (SNG) as the principal product. The fourth case examines coproduction of methanol and SNG. The three SNG Cases are: the Base Case in which the project would utilize Westmoreland Coal and produce excess electricity; the Self-Sufficiency case, where the project is assumed to produce only enough electricity for self use; the third case examines an alternative site for the project utilizing Shell Coal.

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3.2.6.2 Cost of SNG

The overall economic viability of this project depends on the cost of gas at the synfuels plant site (called the plant tailgate price) and the cost of delivering the gas to California. If this cost is competitive with alternatives, then the project is economically visible.

To determine what this cost would be, a series of assumptions were developed and the economics of the project were examined under these assumptions. In addition to the capital and operating costs, additional assumption used in the model are shown in Table 3.2.6-1. Escalation assumptions used are those provided in the California Energy Commission's forecast shown in Table 3.2.6-2.

The economic scenario reflected in these assumptions is one of gradually declining inflation. Interest rates are assumed to stay generally at today's assumed spread over inflation and gradually reduce with the decline in inflation.

To determine whether this project is financially attractive to potential investors, a financial model was created to examine the overall economics of the project. This analysis, which is sometimes called life cycle cost analysis, uses the computer model to find alternative base prices in either 1982 or 1990 (the second year of operations) and determines the rate of return to investors. Where a 1990 cost is found, the inflation assumptions used can be applied to determine the equivalent 1982 price. The rate of return is net of all tax benefits and assumes that all tax credits and deductions are used to offset other tax liabilities and taxable income of the investor.

This analysis does not consider other financial characteristics of the project which are important to equity investors. These include the effect on corporate reported profitability, the timing of equity returns, the magnitude of the cash requirements and the financial risks.

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TABLE 3.2.6-1

CROW SYNFUELS PROJECT
ASSUMPTION USED IN INVESTMENT ANALYSIS

I. Gasification Plant

In-service - January 1, 1989
Plant life - 25 years
Book Depreciation - 25 years (life of plant)
Tax Depreciation - 5 years - ACRS
Debt/Equity - 75/25
Debt Term - 20 years (fixed rate)
Debt Interest - 150 basis points above 20-year Treasury bills at time of drawdown
Return on Equity - 15 percent real rate based on DCF-ROE calculation
Income Taxes - Federal - 46 percent
Montana - 6.75
Ad Valorem Taxes and Insurance - 2.5 percent of plant investment (included in operating costs)
Tax Credits - ITC - 10 percent
ETC - none
Working Capital - 2 months O&M
Loan guarantee fee - 1/2 percent of outstanding principal
Startup Production:
First testing - October 1, 1988
First sale to pipeline - January 1, 1989
Maximum operating efficiency (91%) - July 1, 1989
Total 1989 SNG production 30,688 MMCF

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TABLE 3.2.6-1 (Continued)

CROW SYNFUELS PROJECT
ASSUMPTION USED IN INVESTMENT ANALYSIS

Construction Schedule

Procurement release	12/1/85
Site Preparation	1/1/86
Effective Start of Construction	7/1/86

Feedstock Requirement - 5.976 MM Tons Coal/yr.

II. SNG Pipeline

In-service date - January 1, 1989

Construction period - 18 months

Plant life - 25 years

Average daily flow after July 1, 1989 - 125 MMCFD

Definitions:

1A - Site 1, Western Leg

1B - Site 1, Rocky Mtn. Sys.

2A - Site 23, Western Leg

2B - Site 23, Rocky Mtn. Sys.

Cost Data (Thousands of 1982 $'s)*

	1A	1B	2A	2B
Capital Investment	157,500	260,700	165,900	266,700
Annual Operating Exp.	300	500	300	500
Working Capital	37.5	62.5	37.5	62.5

*Source - Transportation Study

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TABLE 3.2.6-1 (Continued)

CROW SYNFUELS PROJECT
ASSUMPTION USED IN INVESTMENT ANALYSIS

Financial Data

Federal Income Tax - 46 percent
Montana Income Tax - 6.75 percent
Debt/Equity - 70/30
Debt Interest - 100 basis points above 10-year Treasury Notes
Equity Return - 2.5 percent above debt interest
ITC - 10 percent of construction cost
Ad Valorem Taxes - 1.5 percent plant investment
Book Depreciation - 20 years-straight line
Startup production - see Gasification Plant

III. 3rd Party Transportation Costs*

	1A	1B	2A	2B
Capital Investment	-	21,100	-	21,100
Annual Operating Exp.	56,700	50,300	56,700	50,300
Gas Consumption	10%	1.4%	10%	1.4%

IV. Byproduct Sales

	Unit Price	Annual Output	Escalation Index
Ammonia	$235/Ton	25,500 Tons	Natural gas
Naphtha	$268/Ton	65,100 Tons	Rocky Mtn. Distillate
Sulfur	$ 60/Ton	28.900 Tons	PPI
Electricity	$ 4¢/kWh	2.25 x 10^6MWh	Rocky Mtn. Wholesale Power Rate

First year's (1989) estimated revenue form byproducts - $115.2 million (1982$'s).

*Source - Transportation Study
**Based on 125 MMCF/CD

TABLE 3.2.6-2

GAS PRICE FORECAST
CFM IV
NGPA AS ENACTED
INFLATION ASSUMTIONS

Year	PGNP* Annual Percentage Increase	Oil Price Annual Percentage Real Increase	Crude Oil Price $/Bbl**	No. 6 .5% Sulphur $/Bbl***	No. 6 .25% Sulphur $/Bbl***	No. 2 Distillate Oil $/Bbl**
1982	8.00	-13.36	32.75	32.75	36.03	40.94
1983	8.00	-3.87	34.00	35.70	38.42	44.20
1984	8.00	0.00	36.72	39.81	42.23	47.74
1985	7.00	1.00	39.69	43.02	45.64	51.59
1986	7.00	1.00	42.89	46.49	49.32	55.75
1987	7.00	1.00	46.35	50.24	53.30	60.25
1988	7.00	1.00	50.09	54.30	57.60	65.12
1989	7.00	1.00	54.13	58.68	62.25	70.37
1990	6.00	1.50	58.24	63.13	66.98	75.71
1991	6.00	1.50	62.66	67.92	72.06	81.46
1992	6.00	1.50	67.42	73.08	77.53	87.64
1993	6.00	1.50	72.53	78.63	83.41	94.29
1994	6.00	1.50	78.04	84.59	89.74	101.45
1995	6.00	1.50	83.96	91.01	96.56	109.15
1996	6.00	1.50	90.33	97.92	103.88	117.43
1997	6.00	1.50	97.19	105.35	111.77	126.35
1998	6.00	1.50	104.57	113.35	120.35	135.94
1999	6.00	1.50	112.50	121.95	129.38	146.26
2000	6.00	1.50	121.04	131.21	139.20	157.36
2001	6.00	1.50	130.23	141.17	149.76	169.30

* Implicit Price Deflator, Gross National Product

** Refiner's Average Acquisition Cost

*** Wholesale Price

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3.2.6.2 (Continued)

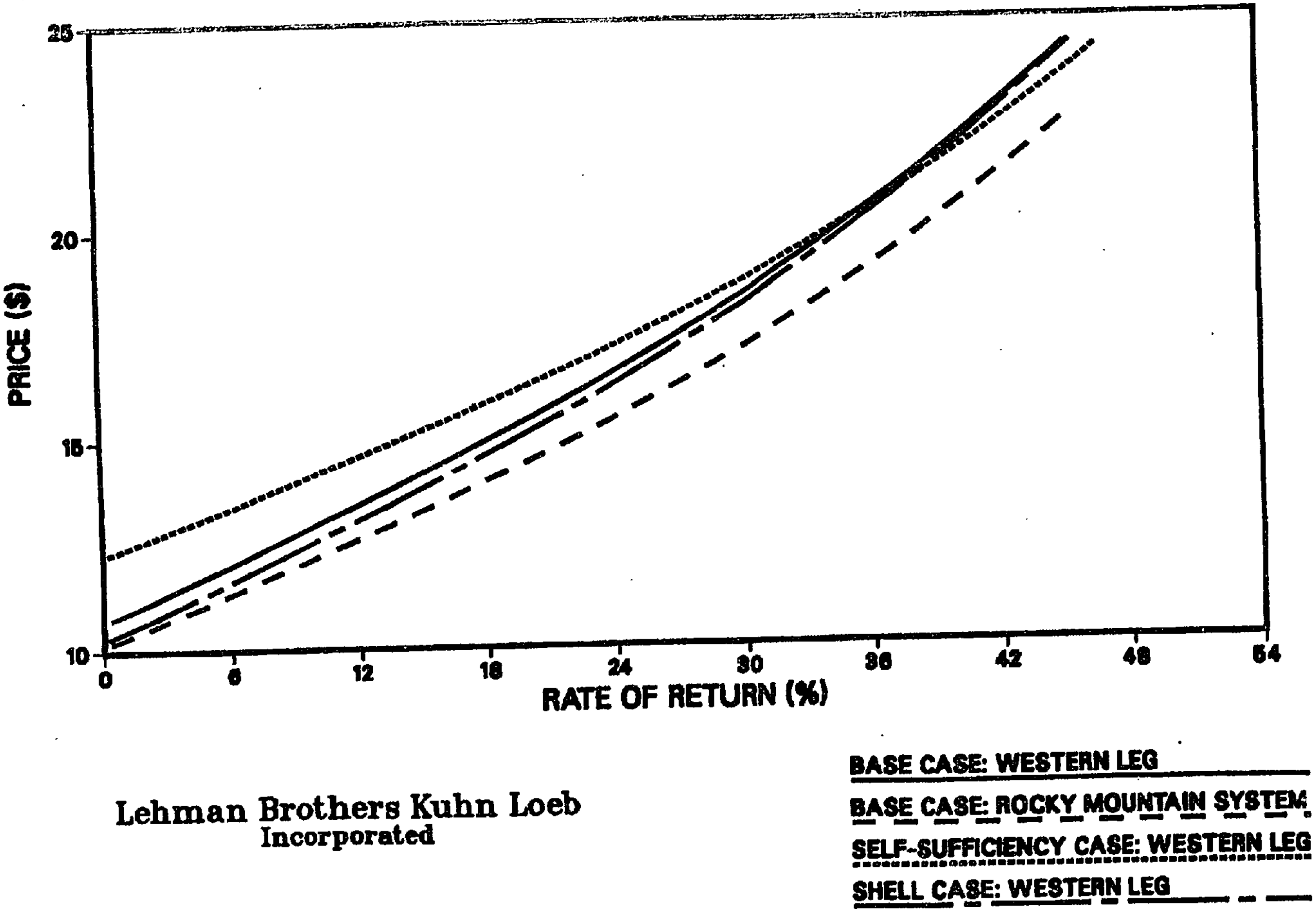
The delivered price in 1990 is shown in Figure 3.2.6-1 where prices and costs are escalated according to the previously stated assumptions provided by the California Energy Commission. The year 1990 is used because it is the first full year of operations. The equivalent plant tailgate price is shown in Figure 3.2.6-2.

These results are shown in tabular form in Table 3.2.6-3 for the Base Case. In order to meet a minimum required real rate of return on equity of 15 to 20 percent, the escalated rate must be in the range of approximately 23 to 28 percent. Equivalently, to meet this return the 1982 plant tailgate SNG price must be in the range of \$6.00 to \$7.00 at the beginning of 1982. This assumes that the real price escalation projected by the California Energy Commission holds true together with the other assumptions used. The risks of this project could require a higher expected return by some sponsors and a higher 1982 gas price.

Table 3.2.6-4 is a summary of plant tailgate cost of SNG assuming a 22 percent rate of return on equity for the four cases considered along with results of a cost reduction case. Preliminary analysis of a plant located at the Westmoreland mine that was power self-sufficient, burned the liquid byproducts, eliminated coal transportation costs, and made no provision for future plant expansion (Cost Reduction Case) could reduce the capital costs and operating costs compared to the Self-sufficient case. Detailed investigation of this alternative is recommended for the next phase of the project.

FIGURE 3.2.6-1

DELIVERED PRICE
INFLATED DOLLARS; LEVERAGED CASE

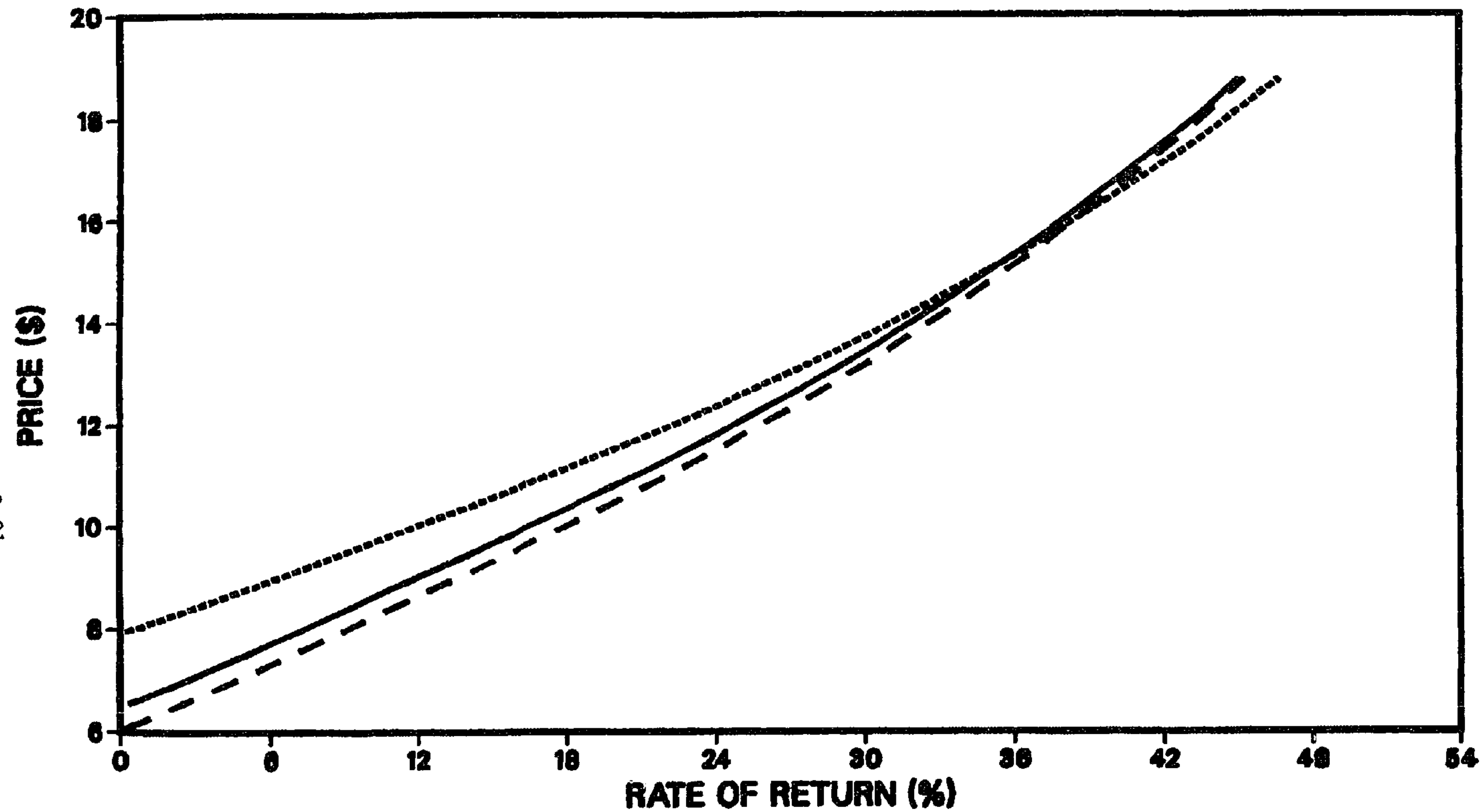


Lehman Brothers Kuhn Loeb
Incorporated

FIGURE 3.2.6-2

PLANT TAILGATE PRICE

INFLATED DOLLARS; LEVERAGED CASE



BASE CASE

SHELL CASE

SELF-SUFFICIENCY CASE

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Incorporated

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TABLE 3.2.6-3

SNG PRICE VERSUS RATE OF RETURN
BASE CASE WITH WESTERN LEG TRANSPORTATION

Tailgate Price 1982(a)	Tailgate Price 1990	Delivered Price 1990	Rate of Return
$ 3.75	$ 7.02	$11.31	2.7%
4.00	7.49	11.83	4.9
4.25	7.96	12.35	7.1
4.50	8.43	12.87	9.3
4.75	8.90	13.39	11.5
5.00	9.36	13.91	13.6
5.25	9.83	14.42	15.7
5.50	10.30	14.95	17.8
5.75	10.77	15.47	19.8
6.00	11.24	15.99	21.8
6.25	11.71	16.51	23.7
6.50	12.17	17.03	25.4
6.75	12.64	17.55	27.2
7.00	13.11	18.07	28.9
7.25	13.58	18.59	30.5
7.50	14.05	19.11	32.1
7.75	14.51	19.63	33.6
8.00	14.98	20.15	35.0
8.25	15.45	20.67	36.4
8.50	15.92	21.19	37.8
8.75	16.39	21.71	39.0
9.00	16.86	22.23	40.3

(a) Price at the beginning of 1982.

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TABLE 3.2.6-4

SUMMARY OF SNG PRICES

Case	Capital Cost $ million	Net Operating $ million	Cost-of-Service $/million Btu
Base Case	2,036.4	79.9	6.03
Self-sufficiency Case	1,671.5	127.5	6.37
Coproduction Case*	2,047.7	109.8	6.03**
Shell Coal Case	2,093.9	67.2	5.88
Cost Reduction Case	1,288.1	109.3	5.20

*Methanol price - $8.40/million Btu

**If methanol is sold on a parity with SNG, the price would be $7.10 to 7.20/million Btu.

ROE = 22 percent

1982 Price Basis

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3.2.6.3 Project Financing

The financing requirements for the project are shown in Table 3.2.6-5. The assumed inflation rate for construction costs is the overall general price level escalation shown previously in Table 3.2.6-2. With inflation, total construction costs equal $3.15 billion. The analysis assumes that 75 percent of total project costs are financed by debt. Total project costs include capitalized interest of $518 million. Therefore, the total financing requirements are approximately $3.66 billion. Of this total amount, 75 percent is funded by debt with the balance paid by the equity investor. The equity requirements total $916 million spread over the construction period as shown in Table 7.2.6-5.

Under present tax law, interest deductions and tax credits for qualified construction costs are eligible for use during the construction period. The availability of these tax benefits reduces the net equity investment during the construction period from $916 million to $394 million.

3.2.6.4 Price Guarantees

The results indicate that the project needs price guarantees together with the loan guarantees. The form of price guarantee necessary is dependent on the expectations of potential sponsors and the risks that they are willing to take.

The attachment at the end of this section shows the projected operating results where the project receives a plant tailgate price guarantee of $6.75 per million Btu at the beginning of 1982 and escalates with general price inflation. The overall return on equity in this case is 27 percent. The project returns initial investment under this case in 1991, the third year of operation. Book income before taxes becomes positive in the following year (1992).

TABLE 7.2.6-5

CONSTRUCTION PERIOD COSTS AND EQUITY REQUIREMENTS

($ Millions)

	1982	1983	1984	1985	1986	1987	1988	1989	TOTAL
Inflated									
Construction Costs	$1.84	$20.41	$45.98	101.63	$654.49	$1,202.62	$ 987.60	$130.92	$3,145.49
Capitalized Interest	0.21	1.42	5.44	12.13	53.07	160.09	285.86	0.00	518.22
Total Financing Requirements	2.04	21.84	51.42	113.76	707.56	1,362.71	1,273.46	130.92	3,663.71
New Construction Debt	1.53	16.38	38.57	85.32	530.67	1,022.03	955.09	98.19	2,747.78
Equity Requirement	0.51	5.46	12.86	28.44	176.89	340.68	318.36	32.73	915.93
Cash Valve of Interest Deduction	0.10	0.65	2.50	5.58	24.41	73.64	131.49	0.00	238.37
Total Tax Credits	0.17	1.84	4.14	9.15	58.90	108.24	88.88	11.78	283.10
Net Equity Requirements	$0.25	$2.97	$6.21	$ 13.71	$ 93.57	$ 158.80	$97.99	$ 20.95	$ 394.45

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3.2.6.4 (Continued)

The $6.75 price is intended to be representative of the level of price guarantee necessary. However, an assessment of the project risks could lead potential sponsors to require an even higher price guarantee.

Although price guarantees of this level or higher are necessary to provide sufficient incentive to attract investors, a problem arises in that the SFC authority is limited. The overall financial commitment to any project cannot exceed a total of $3 billion. Under the 75 percent leverage case, $2.7 billion is required for loan guarantees. This leaves only $300 million available for price guarantees.

The overall price guarantee funding requirement for price guarantees is shown in Case C if SNG is priced in California at the forecasted crude price. By the tenth year in the crude price case the SFC under this formula would pay total outlays of $3.4 billion against the SFC price guarantee. Even if the project were privately financed, or the loan guarantees were provided only during the construction period, in the crude pricing scenario the SFC could make price guarantees for only 9 years. Past the 9th year the available $3 billion would be utilized.

When the SNG is priced at the distillate level in California, the maximum forecasted cumulative payment under this price guarantee is $2.4 billion in 1986. After this point, the model assumes that price guarantees are repaid.

In this case also, the total loan guarantee and price guarantee authority exceeds the maximum $3 billion. Some nonguaranteed financing after startup would be necessary to allow the SFC to make required projects under the $3 billion ceiling.

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3.2.6.4 (Continued)

If private lenders are willing to take the risk of some private debt to the project, and additional equity contributions are available, the project could be feasible. It is not feasible if a 75 percent loan guarantee is required together with adequate price guarantees at today's price levels for natural gas.

3.2.6.5 Sensitivity Analysis

Sensitivity analysis was performed on a number of variables in the financial model. The results of this sensitivity analysis are shown in the following three tables.

Table 3.2.6-6 shows the sensitivity of the project to capital cost escalation and to failure of the project to operate in the first year of startup. The startup delay assumes that the plant is in service for tax purposed but produces insignificant quantities of gas for sale.

The sensitivity of the project to escalation of coal prices is outlined in Table 3.2.6-7. Unless a coal purchase contract can limit escalation of future real coal prices, escalation of real coal prices will cause a moderate reduction in returns.

As shown in Table 3.2.6-8, similar modest reductions in return will occur if interest costs are 100 to 200 basis points higher than expected. Higher levels of interest rates would tend to be accompanied by different inflation assumptions. Alternative inflation assumptions were not examined. However, if rapid inflation occurs after startup, the returns to the sponsors will be greatly enhanced.

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TABLE 3.2.6-6

SENSITIVITY ANALYSIS
EFFECT ON RATE OF RETURN OF COST AND OPERATING CHARGES

Gas Price	Base Case	50% Capital Cost Overrun	Failure to Operate 1st Year
4.00	5.0%	-2.0%	3.7%
4.50	9.3	1.3	7.3
5.00	13.6	4.5	10.7
5.50	17.8	7.5	13.8
6.00	21.8	10.4	16.7
6.50	25.5	13.3	19.5
7.00	28.9	16.2	22.2
7.50	32.1	19.0	24.6
8.00	35.0	21.7	26.9

TABLE 3.2.6-7

SENSITIVITY ANALYSIS
EFFECT ON RATE OF RETURN OF VARIATIONS IN COAL PRICES

	Real Coal Price Growth				
Gas Price	-2%	-1%	Base Case	+1%	+2%
4.00	8.8%	7.2%	5.0%	1.7%	-4.3%
4.50	12.8	11.3	9.3	6.6	2.1
5.00	16.8	15.4	13.6	11.2	7.7
5.50	20.6	19.3	17.8	15.7	12.8
6.00	24.3	23.1	21.8	20.0	17.6
6.50	27.7	26.7	25.5	24.0	22.0
7.00	30.9	30.0	28.9	27.6	26.0
7.50	33.9	33.0	32.1	30.9	29.5
8.00	36.7	35.9	35.0	34.0	32.8

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TABLE 3.2.6-8

SENSITIVITY ANALYSIS
EFFECT ON RATE OF RETURN OF VARIATION IN INTEREST RATES

Gas Price	Base Case	+100 Basis Points	+200 Basis Points
4.00	5.0%	3.9%	3.0%
4.50	9.3	8.1	6.9
5.00	13.6	12.1	10.7
5.50	17.8	16.1	14.5
6.00	21.8	20.0	18.3
6.50	25.5	23.7	22.0
7.00	28.9	27.2	25.5
7.50	32.1	30.5	28.9
8.00	35.0	33.6	32.0

3.2.6.6 Coproduction of Methanol and SNG

The financial analysis also examined the case where methanol would be coproduced with SNG. If the demand for methanol were to grow such that methanol could be sold at a value substantially above its comparable SNG Btu value, coproduction could be a viable alternative.

The rate of return of the plant under alternative methanol and SNG prices is shown in Table 3.2.6-9. A methanol price of $10 per million Btu with SNG prices at $6.00 per million Btu provides an acceptable rate of return.

If methanol prices were to increase from the $10 per million Btu level, coproduction of natural gas could result in economic SNG prices.

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TABLE 3.2.6-9

RATE OF RETURN
OF COPRODUCTION OF SNG AND METHANOL
UNDER ALTERNATIVE PRODUCT PRICES (a)

SNG Price (b)	$5.00	$6.00	$6.38	$7.00
Methanol Price (b)				
($1982)				
2.00	-8.6	-2.7		2.1%
4.00	1.3	5.7		10.0
6.00	9.2	13.4		17.4
8.00	16.7	20.6	22.0	24.3
10.00	23.7	27.2		30.3

(a) Assumes 75% debt with inflated dollars to calculate rate of return

(b) SNG and Methanol Prices in $/MMBtu

3.2.7 Project Risks

The major risks for financial sponsors of the project can be enumerated as follows:

1. Project abandonment prior to commencement of operations due to cost overruns, technical failure, environmental regulations or any other reason

2. Delays in timing and cost overruns during construction

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3.2.7 (Continued)

3. Higher than anticipated operating costs, particularly feedstock costs and maintenance costs

4. More onerous environmental requirements than originally anticipated and accompanying higher cost

5. The failure of the plant to meet designed output capacity

6. Technical obsolescence at some point in the future

7. Technology failure

8. Force majeure events including strikes, etc.

9. Higher than anticipated financing costs

10. Availability of a market for the project output

11. Lower than anticipated product prices

12. Changes in tax laws

These risks are present under any project financial structure. Alternative structures shift the risk among the Government and the private sector participants. An example of the differences in risk taking available from loan guarantees, as opposed to price guarantees only, can be viewed by realizing that a non-recourse loan guarantee to the project typically results in the Government taking the majority of the risks in all categories listed. Under a price guarantee the Government takes only a part of the last risk listed, that of the market price of the project's products.

3.2.7 (Continued)

Project cost overruns can be divided into two parts, real cost overruns and price escalation. Real cost overrun risk and the risk of construction delays will be shared by the equity sponsors and the SFC through the loan guarantee. If the price guarantee adjusts with inflation, the risk of cost overruns due to escalation will be mitigated to the extent of available price guarantee authority.

The risk of higher than anticipated operating costs will be shared by the equity sponsors and the SFC through the loan guarantee. The manner in which a price guarantee will operate could provide additional funds to cover higher operating costs.

The risk of higher costs or shutdowns resulting from environmental regulations will be borne in part by the equity sponsors and also by the SFC through the loan guarantee.

Failure of the project to meet capacity or delays due to technology adjustments are lessened by using commercially available technologies. Process performance guarantees and construction guarantees are expected to be available from major equipment vendors and construction companies. To the extent that these guarantees are inadequate this risk will be shared by the equity sponsors and the SFC.

If inadequate demand results from alternatively available fuels at substantially lower prices, the equity sponsors will be protected from this risk in part by the loan guarantee and to the extent of available authority by the price guarantee.

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3.2.7 (Continued)

Project sponsors bear the risk that future changes in tax law will provide less tax benefits than currently available. For example, certain provisions of the tax bill recently passed by the Senate could lower the depreciable base by 50 percent of the tax credits taken. Another bill currently before Congress would require that interest be capitalized for tax purposes and amortized over the first 10 years of operations.

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APPENDIX

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CASE C

COMPUTER RUN

CASE C

CALIFORNIA CRUDE PRICES: WESTERN LEG

CROW INDIAN PROJECT

FINANCIAL INCOME STATEMENT
YEAR END

	1982	1983	1984	1985	1986	1987	1988	1989	1982-89
TOTAL REVENUE	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 495.18	$ 495.18
TOTAL OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	229.97	229.97
DEPRECIATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.27	73.27
INTEREST EXPENSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	352.75	352.75
BOOK INCOME BEFORE TAXES	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$(160.81)	$(160.81)

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CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CASH FLOW

	1982	1983	1984	1985	1986	1987	1988	1989	1982-89
TOTAL REVENUE	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 495.18	$ 495.18
TOTAL OPERATING COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	229.97	229.97
INTEREST EXPENSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	352.75	352.75
NET INCOME TAXES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CHANGE IN NET WORKING CAPITAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.42	57.42
DEBT AMORTIZATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	137.39	137.39
EQUITY REQUIREMENT	0.51	5.46	12.86	28.44	176.89	340.68	318.36	32.73	915.93
CASH FLOW	$(0.51)	$(5.46)	$(12.86)	$(28.44)	$(176.89)	$(340.68)	$(318.36)	$(315.08)	$(1198.28)
LOSSES PASSED THROUGH OR CARRIED FORWARD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	653.73	653.73
CASH VALUE OF INTEREST DEDUCTION	0.10	0.65	2.50	5.58	24.41	73.64	131.49	0.00	238.38
CASH VALUE OF FEDERAL TAX LOSS DEDUCTION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300.71	300.71
INVESTMENT TAX CREDITS	0.17	1.84	4.14	9.15	58.90	108.24	88.80	11.78	283.09
ENERGY TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADJUSTED CASH FLOW	$(0.25)	$(2.97)	$(6.21)	$(13.71)	$(93.57)	$(158.80)	$(97.99)	$(2.58)	$(376.09)
ACCUMULATED ADJUSTED CASHFLOW	(0.25)	(3.22)	(9.43)	(23.15)	(116.72)	(275.52)	(373.50)	(376.09)	
GUARANTEED PRICE	7.29	7.87	8.50	9.10	9.74	10.42	11.15	11.93	
SNG PLANT PRICE	4.91	5.10	5.51	5.95	6.43	6.95	7.51	4.71	
PRICE GUARANTEE PAYMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	216.95	
CUMULATIVE PRICE GUARANTEES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	216.95	
IRR	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	

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CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CASH FLOW

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1982-98
TOTAL REVENUE	$ 495.18	$ 780.93	$ 827.78	$ 877.45	$ 930.10	$ 985.90	$1,045.06	$1,107.76	$1,174.23	$1,244.68	$9,469.06
TOTAL OPERATING COSTS	229.97	365.47	387.40	410.65	435.28	461.40	489.09	518.43	549.54	582.51	4,429.74
INTEREST EXPENSE	352.75	334.89	317.02	299.16	281.30	263.44	245.58	227.72	209.86	192.00	2,723.73
NET INCOME TAXES	0.00	0.00	0.00	0.00	0.00	129.60	154.09	179.52	205.94	233.42	902.57
CHANGE IN NET WORKING CAPITAL	57.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.42
DEBT AMORTIZATION	137.39	137.39	137.39	137.39	137.39	137.39	137.39	137.39	137.39	137.39	1,373.89
EQUITY REQUIREMENT	32.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	915.93
CASH FLOW	$(315.08)	$(56.82)	$(14.03)	$ 30.25	$ 76.12	$(5.93)	$ 18.91	$ 44.70	$ 71.50	$ 99.36	$(934.22)
LOSSES PASSED THROUGH OR CARRIED FORWARD	653.73	825.33	556.07	285.31	12.97	0.00	0.00	0.00	0.00	0.00	2,333.40
CASH VALUE OF INTEREST DEDUCTION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	238.38
CASH VALUE OF FEDERAL TAX LOSS DEDUCTION	300.71	379.65	255.79	131.24	5.96	0.00	0.00	0.00	0.00	0.00	1,073.37
INVESTMENT TAX CREDITS	11.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	283.09
ENERGY TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADJUSTED CASH FLOW	$(2.58)	$ 322.83	$ 241.76	$ 161.49	$ 82.08	$(5.93)	$ 18.91	$ 44.70	$ 71.50	$ 99.36	$ 660.62
ACCUMULATED ADJUSTED CASHFLOW	(376.09)	(53.26)	188.50	350.00	432.08	426.15	445.06	489.75	561.25	660.62	
GUARANTEED PRICE	11.93	12.64	13.40	14.20	15.06	15.96	16.92	17.93	19.01	20.15	
SNG PLANT PRICE	4.71	5.58	6.13	6.73	7.36	8.05	8.79	9.58	10.44	11.36	
PRICE GUARANTEE PAYMENT	216.95	315.66	324.93	334.38	343.96	353.66	363.44	373.26	383.07	392.82	
CUMULATIVE PRICE GUARANTEES	216.95	532.62	857.55	1,191.93	1,535.89	1,889.55	2,252.99	2,626.24	3,009.31	3,402.13	
IRR	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	

CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CROW INDIAN PROJECT

TAX STATEMENT
YEAR END

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1982-98
TOTAL REVENUE	$ 495.18	$ 780.93	$ 827.78	$ 877.45	$ 930.10	$ 985.90	$1,045.06	$1,107.76	$1,174.23	$1,244.68	$9,469.06
TOTAL OPERATING COSTS	229.97	365.47	387.40	410.65	435.28	461.40	489.09	518.43	549.54	582.51	4,429.74
TAX DEPRECIATION	566.19	905.90	679.42	452.95	226.47	0.00	0.00	0.00	0.00	0.00	2,830.94
INTEREST EXPENSE	352.75	334.89	317.02	299.16	281.30	263.44	245.58	227.72	209.86	192.00	2,723.73
UNADJUSTED NET INCOME BEFORE TAXES	$(653.73)	$(825.33)	$(556.07)	$(285.31)	$(12.97)	$ 261.06	$ 310.39	$ 361.61	$ 414.83	$ 470.17	$(515.35)
NET INCOME TAXES	0.00	0.00	0.00	0.00	0.00	129.60	154.09	179.52	205.94	233.42	902.57
ADJUSTED NET INCOME AFTER TAXES	$(653.73)	$(825.33)	$(556.07)	$(285.31)	$(12.97)	$ 131.46	$ 156.30	$ 182.09	$ 208.89	$ 236.75	$(1417.92)
TOTAL TAX CREDITS	11.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	283.09
LOSSES PASSED THROUGH OR CARRIED FORWARD	653.73	825.33	556.07	285.31	12.97	0.00	0.00	0.00	0.00	0.00	2,333.40

CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CROW INDIAN PROJECT

FINANCIAL INCOME STATEMENT
YEAR END

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1982-98
TOTAL REVENUE	$ 495.18	$ 780.93	$ 827.78	$ 877.45	$ 930.10	$ 985.90	$1,045.06	$1,107.76	$1,174.23	$1,244.68	$9,469.06
TOTAL OPERATING COSTS	229.97	365.47	387.40	410.65	435.28	461.40	489.09	518.43	549.54	582.51	4,429.74
DEPRECIATION	73.27	146.55	146.55	146.55	146.55	146.55	146.55	146.55	146.55	146.55	1,392.21
INTEREST EXPENSE	352.75	334.89	317.02	299.16	281.30	263.44	245.58	227.72	209.86	192.00	2,723.73
BOOK INCOME BEFORE TAXES	$(160.81)	$(65.98)	$(23.19)	$ 21.09	$ 66.96	$ 114.51	$ 163.84	$ 215.06	$ 268.28	$ 323.62	$ 923.38

CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CASH FLOW

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1982-08
TOTAL REVENUE	$1,319.36	$1,398.52	$1,482.43	$1,571.38	$1,665.66	$1,765.60	$1,871.54	$1,983.83	$2,102.86	$2,229.03	$26859.27
TOTAL OPERATING COSTS	617.46	654.51	693.78	735.40	779.53	826.30	875.88	928.43	984.14	1,043.18	12,568.35
INTEREST EXPENSE	174.14	156.28	138.42	120.56	102.70	84.84	66.98	49.12	31.26	13.40	3,661.41
NET INCOME TAXES	262.01	291.78	322.81	355.17	388.94	424.20	461.04	499.57	539.87	582.06	5,030.02
CHANGE IN NET WORKING CAPITAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.42
DEBT AMORTIZATION	137.39	137.39	137.39	137.39	137.39	137.39	137.39	137.39	137.39	137.39	2,747.78
EQUITY REQUIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	915.93
CASH FLOW	$ 128.36	$ 158.56	$ 190.04	$ 222.86	$ 257.11	$ 292.88	$ 330.25	$ 369.32	$ 410.21	$ 453.00	$1,878.37
LOSSES PASSED THROUGH OR CARRIED FORWARD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2,333.40
CASH VALUE OF INTEREST DEDUCTION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	238.38
CASH VALUE OF FEDERAL TAX LOSS DEDUCTION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1,073.37
INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	283.09
ENERGY TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADJUSTED CASH FLOW	$ 128.36	$ 158.56	$ 190.04	$ 222.86	$ 257.11	$ 292.88	$ 330.25	$ 369.32	$ 410.21	$ 453.00	$3,473.21
ACCUMULATED ADJUSTED CASHFLOW	788.98	947.55	1,137.58	1,360.44	1,617.55	1,910.43	2,240.68	2,610.00	3,020.21	3,473.21	
GUARANTEED PRICE	21.36	22.64	24.00	25.44	26.96	28.58	30.30	32.11	34.04	36.08	
SNG PLANT PRICE	12.36	13.43	14.58	15.82	17.16	18.60	20.16	21.83	23.64	25.58	
PRICE GUARANTEE PAYMENT	402.45	411.90	421.09	429.94	438.34	446.20	453.40	459.80	465.25	469.60	
CUMULATIVE PRICE GUARANTEES	3,804.58	4,216.48	4,637.57	5,067.51	5,505.85	5,952.05	6,405.45	6,865.25	7,330.50	7,800.10	
IRR	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	

CASE C

CALIFORNIA CRUDE PRICES: WESTERN LEG

CROW INDIAN PROJECT

TAX STATEMENT
YEAR END

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1982-08
TOTAL REVENUE	$1,319.36	$1,398.52	$1,482.43	$1,571.38	$1,665.66	$1,765.60	$1,871.54	$1,983.83	$2,102.86	$2,229.03	$26859.27
TOTAL OPERATING COSTS	617.46	654.51	693.78	735.40	779.53	826.30	875.88	928.43	984.14	1,043.18	12,568.35
TAX DEPRECIATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2,830.94
INTEREST EXPENSE	174.14	156.28	138.42	120.56	102.70	84.84	66.98	49.12	31.26	13.40	3,661.41
UNADJUSTED NET INCOME BEFORE TAXES	$ 527.76	$ 587.73	$ 650.24	$ 715.42	$ 783.44	$ 854.46	$ 928.68	$1,006.28	$1,087.47	$1,172.45	$7,798.58
NET INCOME TAXES	262.01	291.78	322.81	355.17	388.94	424.20	461.04	499.57	539.87	582.06	5,030.02
ADJUSTED NET INCOME AFTER TAXES	$ 265.75	$ 295.95	$ 327.43	$ 360.25	$ 394.50	$ 430.27	$ 467.64	$ 506.71	$ 547.59	$ 590.39	$2,768.56
TOTAL TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	283.09
LOSSES PASSED THROUGH OR CARRIED FORWARD	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2,333.40

CASE C

CALIFORNIA CRUDE PRICES: WESTERN LEG

CROW INDIAN PROJECT

FINANCIAL INCOME STATEMENT
YEAR END

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1982-08
TOTAL REVENUE	$1,319.36	$1,398.52	$1,482.43	$1,571.38	$1,665.66	$1,765.60	$1,871.54	$1,983.83	$2,102.86	$2,229.03	$26859.27
TOTAL OPERATING COSTS	617.46	654.51	693.78	735.40	779.53	826.30	875.88	928.43	984.14	1,043.18	12,568.35
DEPRECIATION	146.55	146.55	146.55	146.55	146.55	146.55	146.55	146.55	146.55	146.55	2,857.69
INTEREST EXPENSE	174.14	156.28	138.42	120.56	102.70	84.84	66.98	49.12	31.26	13.40	3,661.41
BOOK INCOME BEFORE TAXES	$ 381.21	$ 441.19	$ 503.69	$ 568.87	$ 636.89	$ 707.92	$ 782.13	$ 859.73	$ 940.92	$1,025.90	$7,771.82

CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CASH FLOW

	2009	2010	2011	2012	2013	2014	1982-14
TOTAL REVENUE	$2,362.77	$2,504.54	$2,654.81	$2,814.10	$2,982.95	$1,581.10	$41759.55
TOTAL OPERATING COSTS	1,105.78	1,172.12	1,242.45	1,317.00	1,396.02	739.89	19,541.60
INTEREST EXPENSE	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	3,661.41
NET INCOME TAXES	624.04	661.48	701.17	743.24	787.83	417.62	8,965.39
CHANGE IN NET WORKING CAPITAL	0.00	0.00	0.00	0.00	0.00	0.00	57.42
DEBT AMORTIZATION	0.00	0.00	0.00	0.00	0.00	0.00	2,747.78
EQUITY REQUIREMENT	0.00	0.00	0.00	0.00	0.00	0.00	915.93
CASH FLOW	$ 632.96	$ 670.94	$ 711.19	$ 753.87	$ 799.10	$ 423.59	$5,870.02
LOSSES PASSED THROUGH OR CARRIED FORWARD	0.00	0.00	0.00	0.00	0.00	0.00	2,333.40
CASH VALUE OF INTEREST DEDUCTION	0.00	0.00	0.00	0.00	0.00	0.00	238.38
CASH VALUE OF FEDERAL TAX LOSS DEDUCTION	0.00	0.00	0.00	0.00	0.00	0.00	1,073.37
INVESTMENT TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	283.09
ENERGY TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ADJUSTED CASH FLOW	$ 632.96	$ 670.94	$ 711.19	$ 753.87	$ 799.10	$ 423.59	$7,464.86
ACCUMULATED ADJUSTED CASHFLOW	4,106.17	4,777.11	5,488.30	6,242.17	7,041.27	7,464.86	
GUARANTEED PRICE	38.25	40.54	42.98	45.55	48.29	51.18	
SNG PLANT PRICE	27.68	29.94	32.37	35.00	37.83	40.87	
PRICE GUARANTEE PAYMENT	472.65	474.22	474.07	471.96	467.61	230.72	
CUMULATIVE PRICE GUARANTEES	8,272.75	8,746.97	9,221.04	9,693.00	10,160.61	10,391.33	
IRR	27.24%	27.24%	27.24%	27.24%	27.24%	27.24%	

CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CROW INDIAN PROJECT

TAX STATEMENT
YEAR END

	2009	2010	2011	2012	2013	2014	1982-14
TOTAL REVENUE	$2,362.77	$2,504.54	$2,654.81	$2,814.10	$2,982.95	$1,581.10	$41759.55
TOTAL OPERATING COSTS	1,105.78	1,172.12	1,242.45	1,317.00	1,396.02	739.89	19,541.60
TAX DEPRECIATION	0.00	0.00	0.00	0.00	0.00	0.00	2,830.94
INTEREST EXPENSE	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	3,661.41
UNADJUSTED NET INCOME BEFORE TAXES	$1,257.00	$1,332.42	$1,412.36	$1,497.10	$1,586.93	$ 841.21	$15725.60
NET INCOME TAXES	624.04	661.48	701.17	743.24	787.83	417.62	8,965.39
ADJUSTED NET INCOME AFTER TAXES	$ 632.96	$ 670.94	$ 711.19	$ 753.87	$ 799.10	$ 423.59	$6,760.21
TOTAL TAX CREDITS	0.00	0.00	0.00	0.00	0.00	0.00	283.09
LOSSES PASSED THROUGH OR CARRIED FORWARD	0.00	0.00	0.00	0.00	0.00	0.00	2,333.40

CALIFORNIA CRUDE PRICES: WESTERN LEG

CASE C

CROW INDIAN PROJECT

FINANCIAL INCOME STATEMENT
YEAR END

	2009	2010	2011	2012	2013	2014	1982-14
TOTAL REVENUE	$2,362.77	$2,504.54	$2,654.81	$2,814.10	$2,982.95	$1,581.10	$41759.55
TOTAL OPERATING COSTS	1,105.78	1,172.12	1,242.45	1,317.00	1,296.02	739.89	19,541.60
DEPRECIATION	146.55	146.55	146.55	146.55	146.55	73.27	3,663.70
INTEREST EXPENSE	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	(0.00)	3,661.41
BOOK INCOME BEFORE TAXES	$1,110.45	$1,185.87	$1,265.81	$1,350.56	$1,440.38	$ 767.94	$14892.83

3.3 LEGAL SUMMARY

3.3.1 Environmental Law

3.3.1.1 Jurisdiction

There is little question that if a synfuels project is built on the Crow Reservation by an entity composed of tribal and nontribal interests, both the federal government and the tribe would have jurisdiction to regulate environmental elements of the project. Much less clear, however, is the question whether the State of Montana would assert jurisdiction over such a project and if so, whether its claim would be valid.

This is an area of the law in which the opinions of the United States Supreme Court, rendered during the past ten to twenty years, indicate that many factors are weighed in reaching a final decision. These factors include:

1) Is the subject area which the state seeks to regulate already comprehensively regulated by the federal government or by the tribal government;

2) Does the state statute interfere with the purposes of federal statutes pertaining to Indian tribes;

3) Does the state statute interfere with the Indian tribe's right to self-government;

4) What is the history of treaties between the United States and the Indian tribe (Crow) and the statutory history pertaining to the Crow Indians;

5) To what State-Indian tribe relationship have the Crows previously accommodated themselves;

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3.3.1.1 (Continued)

6) Is the project on an Indian reservation; and

7) What legitimate state interests are involved.

Obviously these factors require an analysis of the specific state law in question. Such an analysis can be prepared only after a more detailed project proposal is in hand and the state's perspective is understood. Careful planning may well avoid protracted disputes regarding legal jurisdiction.

3.3.1.2 Federal Permits

The proposed synfuels project will be subject to numerous federal environmental regulations. Many of these regulations require the project to obtain a permit prior to commencement of construction or operation. The regulatory process for obtaining each permit will vary according to the type of permit required and the agency with jurisdiction. Typically the permit process takes several months at a minimum and in some instances can be as long as a year. Foremost among the environmental permits which will be necessary will be right-of-way permits from the Bureau of Indian Affairs, a hazardous waste permit, air quality permit, and water quality permit from the Environmental Protection Agency.

In addition to the specific permits required by statute, the proposed synthetic fuels project must comply with the National Environmental Policy Act (NEPA). This will necessitate the preparation of an Environmental Impact Statement (EIS) considering the effects of the project on the environment. The lead agency for purposes of preparing the EIS and considering project impacts will most likely be the Bureau of Indian Affairs.

3.3.1.2 (Continued)

In addition to NEPA and the specified permits, there are several other laws which could apply to the project. These include laws governing mining, cultural resource protection, fish and wildlife protection, archaeological resource protection, and the preservation of floodplains and wetlands.

3.3.1.3 State and Local Permits

The most likely local government to assert jurisdiction over any aspect of the project is Big Horn County. Most of the Crow Reservation is within its boundaries as are the anticipated off-reservation lay-down areas. Big Horn County's jurisdiction, however, is subject to two important limitations: 1) the power of any county government to regulate activities on Indian reservations is wholly derived from the state's regulatory power; and 2) as a matter of policy, Big Horn County does not enforce its ordinances on Indian lands. The county might issue a permit for that portion of a facility built off-reservation, but its power is obviously limited.

While it is unclear whether the State of Montana would assert jurisdiction over the project, the state has enacted a large number of laws requiring that environmental permits are obtained. As with Big Horn County, the state conceivably could issue permits for any portion of the project located off-reservation. Additionally, there is the potential for the state to issue permits for purely Indian activities located wholly within reservation boundaries pursuant to a delegation to the state of a federal permitting function.

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3.3.1.3 (Continued)

Aside from federally-delegated authority, state permitting laws include the Montana Environmental Policy Act and the Montana Major Facility Siting Act, as well as several water and floodway management acts, water and air pollution laws, hazardous and solid waste management requirements, and laws protecting historical and archaeological resources. Permits pursuant to the Montana Strip and Underground Mine Siting Act and the Montana Strip and Underground Mine Reclamation Act might be needed in addition to prospecting and geological permits.

Some federal programs have been delegated in whole or in part to the State of Montana for administration. Under none of these programs, however, does the state presently issue permits on reservation land. While for several years National Pollutant Discharge Elimination System (NPDES) permitting has been turned over to the state, the EPA continues to issue these point source water discharge permits on reservation land. It is anticipated that by the end of 1982, the state will have assumed federal permitting authority for issuing PSD (air quality) and hazardous waste management permits.

3.3.2 Regulatory Law

The manufacture, transportation and sale of coal gas is not regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act. The courts have also clearly established that the manufacture, transportation and sale of coal gas, not commingled with natural gas, is beyond the jurisdiction of the FERC. Therefore, the synfuels plant would not be within FERC jurisdiction, in addition, the pipeline transporting the SNG would not be within FERC jurisdiction.

3.3.2 (Continued)

FERC jurisdiction under the Natural Gas Act would apply to the coal gas once it is commingled with natural gas. This commingling of SNG with natural gas would occur at the point of interconnection with a FERC regulated interstate pipeline. Once commingled, FERC authority would have to be obtained for any subsequent transportation or sale.

The State of Montana does not have any specific statute to regulate natural gas pipelines. There does, however, appear to be a state statute which is written broadly and could be utilized as a basis to regulate an intrastate SNG pipeline. Under this statute, the Montana Public Service Commission (PSC) has the power to establish and enforce rates and regulations for gathering, transporting, loading, and delivering crude petroleum, coal, or the products thereof by pipeline carriers within the state. This language would seem to apply to an SNG pipeline since the gas being transported will be the product of coal.

3.3.3 Water Law

The proposed project when it is operating at its full capacity (250 MMSCF/CD) will require approximately 20,000 acre-feet of water, all of which is consumed. The Crow Tribe under the reserved water rights doctrine has more than sufficient water to meet the demands of the project.

The reserved water rights concept was first announced by the Supreme Court in 1908 in Winters v. United States. Therein, the Court held that when a reservation is established, sufficient water to meet the needs of the reservation is deemed to exist. These needs encompass past, present as well as future uses and is not limited by the amount of water that is actually used at any given time.

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3.3.3 (Continued)

The Crow Tribe has water available to it for use by the project in the Big Horn River, Yellowtail Reservoir as well as the Little Bighorn River and its tributaries. Since the Tribe's right to these waters is based on federal law, it does not have to apply to the State of Montana for a use permit. Moreover, the Tribe's priority date of 1851 is senior to all other users within the respective watersheds; therefore, in times of shortage the Tribe has the right to displace other users to meet its water needs.

Although the quantity of water the Crow Tribe is entitled to under the reserved water rights doctrine is not yet determined, there exists more than a sufficient supply of uncommitted water in the Big Horn River and Yellowtail Reservoir. The Bureau of Reclamation has acknowledged that of the stored water in Yellowtail Reservoir approximately 98,000 acre-feet per year was reserved for the irrigation of agricultural lands in the Hardin Bench unit. That irrigation system has never been constructed. Nonetheless, in 1971, 30,000 acre feet were transferred tentatively for industrial uses for the development of Crow coal reserves. The 30,000 acre-feet is no longer committed to the option-purchase contract for industrial use and it is therefore fair to state that it at a minimum is available if needed for the project.

3.3.4 Indian Law

3.3.4.1 Jurisdiction and Regulatory Authority

The proposed siting of this project on an Indian reservation along with the attendant environmental issues raise the question of which governmental entity has primary regulatory control over the development as well as operational phases of the project. The three principal governmental entities of concern here are the Crow Tribal Council, the United States, and the State of Montana.

3.3.4.1 (Continued)

The Crow Tribal Council will have primary regulatory responsibility inasmuch as the lands and environment to be affected by the project lie within the boundaries of the reservation. However, the United States because it must approve the project in its trustee capacity for the Crow Tribe and because of certain federal statutes which apply on the reservation will have a significant role. The United States, through the Department of the Interior, in determining whether it should approve the project for the Crow Tribe will have to comply with the National Environmental Policy Act of 1969. In addition, certain permits will have to be obtained from the Environmental Protection Agency. These will be permits required by the Clean Air Act, the Clean Water Act and the Resources Conservation and Recovery Act.

It will be extremely important to involve personnel from these respective federal agencies at the beginning and throughout the developmental phase of the project so as to minimize any permit delays. Although the State of Montana does not have direct regulatory control over the proposed project, it is advisable to include representatives of the state on an advisory basis. Having state input may preclude the filing of court actions which would only serve to delay the project.

Once the project is approved and all required federal permits are obtained, other than whatever federal oversight of the permits is required, the Crow Tribal Council will have primacy.

3.3.4.2 Pledging Trust Assets as Collateral

The Crow Tribe has substantial real property assets which could be used or committed in some form to help finance its share of the project. These assets consist of timber, water, surface lands, and deposits of coal,

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3.3.4.2 (Continued)

bentonite, oil and gas. The coal deposits alone consist of approximately 17 billion tons, of which, it is estimated 6 to 7 billion tons under today's economic conditions is strippable.

However, these assets cannot be alienated, mortgaged or pledged without the approval of the United States. As trustee for the Crow Tribe the United States must approve such actions affecting tribal property. The executive branch is charged with this responsibility but it can only act in accordance with federal statutes. That is, unless Congress has vested by statute in the executive the authority to approve the disposition of tribal property, such a disposition is invalid. See, 25 U.S.C. § 177.

Because of this limitation, for the purpose of pledging or alienating tribal properties to help finance this project only certain specific statutes are available. One is 25 U.S.C. § 415 which authorizes the executive branch through the Department of the Interior to approve the leasing of tribal lands for business purposes and the use of natural resources in connection with the operation of such a lease. Under such a lease the Crow Tribe could commit coal and water to the project. Alternatively, the Tribe could lease coal reserves under the 1938 Mineral Leasing Act and by the lease terms have the coal dedicated to the project. Also available is the Act of May 19, 1958 which authorizes the Secretary of the Interior to approve the sale or exchange of restored tribal lands in the so-called "ceded area." This Act appears to permit the direct sale or mortgaging of lands acquired pursuant to it.

3.3.4.3 Business and Tax Status

Because of certain tax immunities enjoyed by the Crow Tribe as a government, the method of ownership of the project between the Tribe and the other participants needs to be closely examined. The Crow Tribe as a

3.3.4.3 (Continued)

government continues to retain the inherent powers to impose taxes on activities within its jurisdictional boundaries. And as a government it also is immune from federal and state taxation statutes.

Thus, income derived from tribal lands and minerals held in trust and accruing to the Tribe is nontaxable. However, Montana like other states has vigorously sought to tax minerals severed by non-Indian lessees from tribal lands. The Crow Tribe through litigation is opposing the imposition of such a tax by Montana. The Tribe in opposing the tax is relying on two broad principles of law laid down by the federal courts to test whether a state statute has application on an Indian reservation. One is the infringement test, that is whether the state law interferes with the right of a tribe to make its own laws and be governed by them. And the other principle is whether the federal government so regulates the area so as to preempt the state statute.

In the area of Indian mineral development the United States in 1938 enacted comprehensive legislation for the purposes of regulating mineral development and encouraging tribal economic development. This Congressional enactment along with certain others serve to negate the imposition by the state of taxes on the development of the Tribe's coal reserves. However, should the project be handled through a lease arrangement the state may seek to impose a Possessory Interest Tax on the leasehold. Such state taxes have been upheld by the courts on the basis that the incidence of the tax does not fall directly on the Tribe but instead is imposed on the non-Indian lessees. Current case law suggests that it may even be possible to overcome this tax should Montana seek to impose one on the project.

3.3.4.3 (Continued)

Despite some of the problems of attempts by the state to tax tribal interests by various methods the fact that the Tribe is generally immune from taxation should not be overlooked when structuring the business organization of the project.

3.3.5 Conclusion

The results of this preliminary legal assessment indicate that there appears to be no insurmountable legal obstacles to the Crow Synfuels Project.

3.4 ENVIRONMENTAL ASSESSMENT

3.4.1 Baseline Description

A summary of existing environmental baseline information on the Crow Reservation, gathered from research of several extensive data bases, is included in this section. The review of this information, discussed in Sections 4.1.1 through 4.1.8 of Volume IV, Part A of this report, is necessary to evaluate and assess the potential environmental impacts that can be expected from the construction and operation of a 125/250 MM SCF/D high-Btu SNG synfuels plant on the reservation. The baseline description addresses the climatology of the area including meteorology and air quality; geology; water resources, including both surface water and groundwater quality and quantity; physiography and land use; soils and vegetation; wildlife resources; seismology; and cultural resources. Primary emphasis within this summary has been placed upon baseline information pertinent to the assessment of major potential environmental impacts to the two candidate plant sites selected for detailed evaluation in this feasibility study; i.e., Sites 1 and 23.

3.4.1.1 Climatology and Air Quality

The Crow Reservation, located in the south-central part of Montana, resides in the transition zone between the Northern Great Plains and the Rocky Mountains, and has a climate which assumes some of the characteristics of both regions. The climate of the reservation area has been classified as continental, semiarid with the associated characteristics of a large range of temperatures, clear skies, and low relative humidities. The reservation, encompassing approximately 2.3 million acres is characterized by rolling plains and complex terrain with elevations ranging from 2,900 feet at Hardin to about 9,000 feet in the Bighorn Mountains. Since climate is dependent

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3.4.1.1 (Continued)

on terrain and elevation, the climate will correspondingly demonstrate variability depending on location and elevation. No attempt has been made to characterize the individual site areas of Sites 1 and 23 according to climate because no site-specific data are available. Although these data are an essential requirement for subsequent, detailed air quality modeling for the final assessment of air quality impacts arising from the proposed synfuels project, the EPA-approved screening techniques adapted for the predictive air dispersion modeling used in this study do not require site-specific detailed monitoring data. For this reason, less emphasis was placed upon a discussion of the available climatology and air quality data in this summary, although a quite detailed account of the available baseline information is presented in the body of the report (see Section 4.1.1 of Volume IV, Part A). Summarily, a detailed, site-specific, preoperational air monitoring program to develop the required baseline climatological, meteorological, and air quality data becomes an absolute necessity when the synfuels project proceeds.

The Crow Reservation is currently designated as a Class II PSD area, with no violations of human health-related ambient air quality standards noted on the reservation. The Class II designation is the same classification that applies to most of the geographic areas of the country. It implies that a moderate level of industrial growth would be permitted.

Most of the area adjacent to the reservation is also designated as Class II air quality, with two very important exceptions. The Northern Cheyenne Reservation located directly to the east of the Crow Reservation has been designated as a Class I PSD area. The designation is reserved for clean, pristine areas and would permit little or no industrial development. Since industrial sources located on the Crow Reservation could affect the air quality on the Northern Cheyenne Reservation, the Class I status of the Northern Cheyenne is a significant factor in this feasibility analysis.

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3.4.1.1 (Continued)

The other air quality designated area which may have an impact on any development on the Crow Reservation is the city of Billings. Billings is currently classified as "nonattainment" for Total Suspended Particulates (TSP), meaning that violations of the health standard for TSP have been measured in Billings and that little or no growth will be permitted in or adjacent to Billings until the standard is reached.

3.4.1.1.1 Odor

No odor monitoring has been performed at any of the sites. It is anticipated that odor levels on the reservation are similar to those associated with rural dryland farming areas in the country. Certain monitoring odor occurrences related to agricultural activities may be present during harvest time.

3.4.1.1.2 Acid Precipitation

The acidic character of precipitation that occurs over a given area has been an issue of increasing concern. The emission of man-made pollutants from industrial and urban activities can increase the acidity of the precipitation that falls to the ground. The effects of acid precipitation on the environment are not clearly understood; however, increased precipitation acidity can cause (1) damage to lakes and rivers, (2) demineralization of soils, (3) reduction of crop and forest productivity, and (4) deterioration of property.

No measures of acid precipitation have been made on the reservation. However, data collected near Colstrip by the University of Montana indicate that acid rains are occurring in the area. Further studies are needed to investigate the baseline acidic precipitation on the reservation.

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3.4.1.2 Geology

The sedimentary rocks of the Crow Reservation total approximately 11,000 feet thickness, not including the Precambrain granitic basement rocks found in the eroded and uplifted core of the Bighorn Mountains. Every geologic system except the Silurian is represented within the reservation boundaries. Precambrian to Mississippian strata generally outcrop in the southwest part of the reservation. Pennsylvanian and younger rocks are found in the northern and eastern portions of the area.

The general stratigraphy of the reservation is presented in Table 4.1.2-1 and Figure 4.1.2-1 of Section 4.1.2 of Volume IV, Part A, for the formations which outcrop within the boundaries of the reservation. Geologic characteristics pertinent to Sites 1 and 23 that are germane to the subsequent environmental impacts assessment are summarized in Sections 4.1.2.1 and 4.1.2.2 of Volume IV, Part A.

3.4.1.2.1 Site 1

The proposed Site 1 area is located in parts of Secs. 16, 17, 20, and 21, T2S R31E. The general region encompassing Site 1 is overlain by the Niobrara and Carlile members of the Cody Shale Formation of the Upper Cretaceous Series (see Figure 4.1.2-2 of Section 4.1.2, Volume IV, Part A). The Cody Shale includes 2,600 feet of dark-gray, partly sand shale which underlies must of the plains region in southcentral Montana. The Cody Shale is conformable above the Frontier Formation and under the Parkman Sandstone and includes rocks of the Colorado and Montana Groups.

A series of test holes were recently drilled by Woodward-Clyde Consultants (1980) in Secs. 9, 16, and 17, T2S R31E, slightly north of the candidate Site 1 area. The results of this preliminary test drilling showed stiff to very stiff clays over hard to very hard bedrock, presumably the Niobrara and Carlile Members of the Cody Shale Formation, at depths of 3-7 feet.

3.4.1.2.1 (Continued)

The upper 5 feet of bedrock had weathered in one of the test holes. Additionally, the clays were silty, sand, calcareous, and occasionally porous. The claystone bedrock was slightly sandy to sandy and contained scattered bentonitic clay lenses.

A near-vertical fault crosses Woody Creek Dome, trending from Sec. 33, T3S R31E into Sec. 11. This fault ends in a very short distance in Cody shale south of the dome and has a maximum vertical displacement of about 100 feet. A similar fault in Secs. 3 and 9, west of the anticlinal axis extending northward from Woody Creek Dome, has prominent surface expression, and on the north side of Woody Creek Valley it displaces the white-weathering calcareous Greenhorn Shale member of the Cody Shale nearly 100 feet.

Several other smaller faults on the north side of the valley are an echelon to the Woody Creek Dome fault, and occur in a belt parallel to the axis of the northward-plunging Two Leggin Uplift. Structural closure along the faults is less than 100 feet. One of these faults, approximately 5 miles in length, nearly bisects the proposed Site 1 area (see Figure 4.1.2-1 of Section 4.1.2, Volume IV, Part A).

3.4.1.2.2 Site 23

The proposed Site 23 is located in sec. 11, T9S R38E, and is adjacent to the proposed Shell coal mining leases (see Figure 4.1.2-3 of Section 4.1.2, Volume IV, Part A). The topography of the general area is characterized by a series of relatively narrow, flat-topped surfaces or plateaus that dip gently from northwest to southwest, separated by narrow stream valleys occupied by Squirrel, Tanner, and Youngs creeks and their lesser subsidiary drainages.

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3.4.1.2.2 (Continued)

Four coal seams, representative of the stratigraphy of the area and averaging 10-48 feet in thickness, are the object of the proposed nearby Shell mining project. The four coal seams are part of the Tongue River member, which is the youngest (uppermost) unit of the Fort Union Formation.

The Wasatch Formation constitutes the uppermost bedrock unit at higher elevations in the western and northern portions of the Site 23 Shell lease area and in the Wolf Mountains. The Tongue River Formation is the uppermost unit of bedrock in the southern part of the lease and along the valleys of Youngs, Tanner, and Squirrel creeks where erosion has removed the overlying Wasatch.

Figure 4.1.2-3 of Section 4.1.2, Volume IV, Part A, illustrates the surficial relationship among the bedrock formations across the lease and the proposed siting area. Geologic units and formations significant to the site are also tabulated (see Table 4.1.2-2 of Section 4.1.2, Volume IV, Part A).

The Shell coal lease and Site 23 are on the northern flank of the Ash Creek anticline. This anticline causes the general southeasterly dip of regional bedding to be warped to the northeast at an average dip of 2 degrees through the general area. Prominent structural features on the lease include the clearly defined northeast and northwest lineations, consisting of a series of northeast-southwest trending normal faults that transect the area, are not as obvious because they are masked by overlying undisturbed sediments. The down-dropped block is on the southeastern side of the faults, and strata on the side of the faults commonly dip abruptly into the faults.

Several parallel faults in the southeastern part of the Shell lease area show apparent displacements ranging from 10 to 200 feet. Movement along these faults is assumed to have occurred in a steep to near-vertical plane.

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3.4.1.3 Water Environment

The Crow Reservation is located in the Yellowstone River Drainage. Lands within the reservation are drained by eight basins: Sarpy Creek, Tullock Creek, Rosebud Creek, Tongue River, Little Bighorn River, Bighorn River, Fly Creek, and Pryor Creek (see Figure 4.1.3-1 of Section 4.1.3, Volume IV, Part A). The Bighorn River, Little Bighorn River, and Pryor Creek drain most of the reservation. The Little Bighorn River drainage, covering about 600,000 acres, drains most of the eastern part of the reservation. The lesser drainages on the eastern reservation boundary include Tullock Creek, Sarpy Creek, Rosebud Creek, and Tongue River. Tullock Creek drains to and joins the Bighorn River north of the reservation near Bighorn, Montana. Sarpy Creek drains north directly to the Yellowstone River. Rosebud Creek drainage consists of several small tributaries draining to the Rosebud Creek east of the reservation.

3.4.1.3.1 Surface Water

A Lurgi coal gasification facility capable of producing a maximum of 250 MM SCF/D SNG will require a regulated water supply of 14,000 gpm (31 cfs). Therefore, an analysis and evaluation of the foregoing surface drainages and their surface flow characteristics on the Crow Reservation revealed that the Yellowstone Reservoir (Bighorn Lake) and the Bighorn River currently constitute the only regulated supply of water on the reservation that will satisfy on a continuing basis, the aforementioned design requirements for either Site 1 or Site 23.

Allowing for inflows and diversions, the average annual flow in the Bighorn River in the reach of potential water withdrawal for synfuels development is 2,652,000-2,728,740 ac-ft/yr (see Figure 4.1.3-2 of Section 4.1.3, Volume IV, Part A). Flow in the Bighorn River normally peaks between May and July due to snowpack runoff. The flow variability in the Bighorn River below Yellowtail Dam at St. Xavier is influenced by Bighorn Lake

3.4.1.3.1 (Continued)

but, since the storage capacity of 1.4 million ac-ft/yr is only about 57 percent of the average annual inflow to the lake, a portion of the peak inflows spill over Yellowtail Dam. During the four-water-year period of 1975 through 1978, the average monthly flow ranged from 28 percent to 267 percent (1,085 and 10,240 cfs respectively) of the average flow of 2,838 cfs (see Figure 4.1.3-3 of Section 4.1.3, Volume IV, Part A). The four-water-year average flow of 3,838 cfs is about 6 percent higher than the long-term average flow of 3,603 cfs. Flow duration curves show the flow to be 2,200 cfs or greater during 80 percent of the time for the period 1966-1979 (see Figure 4.1.3-3 of Section 4.1.3, Volume IV, Part A). The lowest single day flow during that period was 112 cfs in 1968 in the Bighorn River at St. Xavier and 400 cfs in 1968 near Bighorn, Montana.

Although not contemplated as a source of water supply for the proposed synfuels project, four perennial drainages are located in the southeastern part of the reservation in the proposed Shell mining Site 23 area. Three of these perennial streams - Youngs Creek, Tanner Creek, and Little Youngs Creek - drain the proposed Shell mine sites. The fourth drainage, Squirrel Creek, flows in a southeasterly course slightly north of the Site 23 area. All four drainages are tributary to the Tongue River. These streams flow in a southeasterly direction in deeply incised parallel valleys. The drainage basins in the mine areas are only about 2 miles wide and have an average topographic relief between valley bottom and uplands of 300 feet. The alluvial deposits in the valleys are generally less than 40 feet deep and 1,000 feet wide. The approximate average width of alluvial deposits in Youngs Creek is 600 feet, and the average width in Little Youngs and Tanner Creeks is approximately 400 feet.

Thick clinker beds outcrop over much of the drainage basin of Little Youngs Creek and Youngs Creek but do not occur in the Tanner Creek drainage. The clinker beds control the flow regime of Youngs Creek and

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3.4.1.3.1 (Continued)

Little Youngs Creek to a large degree. The very porous and permeable clinker beds are the recharge area for many small groundwater flow systems which discharge to the creeks and maintain relatively high base flows of good-quality water in the creeks. The high infiltration rates in the clinkered area greatly affect peak stream flows in the creeks relative to other streams in nonclinkered area. The proposed mine site are also has a number of ephemeral tributaries that drain into the perennial streams.

3.4.1.3.2 Groundwater

Groundwater is available and has been developed for limited use throughout the Crow Reservation. In fact, groundwater constitutes the entire water supply for the Westmoreland Resources Absaloka coal mining operation in the northeastern part of the reservation. The major sources of groundwater on the Crow Reservation are the local deposits of alluvium and colluvium of recent (Quarternary) age, and the sandstones, limestones, and coal beds of the bedrock formations underlying the reservation.

The alluvium and terrace deposits along the major streambeds on the Crow Reservation are the most readily available groundwater supplies. Both Quarternary alluvium and Pleistocene terrace deposits are found in the valley fill along the Little Bighorn River (see Figure 4.1.2-2, Section 4.1.2, Volume IV, Part A). Water yields from the alluvium are estimated to be 50 gpm to 450 gpm. The high-end of the range would require thick, saturated deposits having high permeability or the use of an infiltration/collection gallery system. Yields from the terrace deposits are probably less than 50 gpm (see Table 4.1.3-4 of Section 4.1.3, Volume IV, Part A).

One of the most promising candidate siting areas for the synfuels facility, Site 1, is overlain primarily by two of the lower members of the Cody Shale formation, the Carlile and Niobrara, in the Colorado Group, as previously

3.4.1.3.2 (Continued)

discussed. Since pertinent well data are not available at the Site 1 location, the drill test data recently developed are somewhat indicative of the groundwater potential in that area.

No free water was found in any of the test holes drilled to a maximum of 20 feet. Additionally, the Cody Shales are generally considered to be poor sources of groundwater capable of yielding 50 gpm or less and to occur at depths of 600-3,500 feet (see Table 4.1.3-5 and Figure 4.1.3-6 of Section 4.1.3, Volume IV, Part A).

In the Site 23 area, alluvial deposits exist in the valleys of Squirrel, Little Youngs, Youngs, and Tanner Creeks. The alluvial deposits are lithologically variable, containing lenticular deposits of fine sand, silt, clay and clinker gravels varying in thickness 40 to 60 feet. The width of alluvial deposits is generally less than 1,000 feet.

The Tongue River Member of the Fort Union Formation is composed of several major coal seams, interbedded sandstone, siltstone, shale, and clinker beds. The major coal seams - Smith, Anderson, Dietz, and Canyon - and their associated clinkers are the principal water-bearing units in the Tongue River Member and, hence, in the Site 23 area. Locally thick sandstone beds between the coal beds are water-yielding, but the sandstones occur as discontinuous lenses that appear to be isolated bodies with very limited hydraulic connection.

The interburden between the coal seams generally has a hydraulic conductivity that is several orders of magnitude lower than that in the coal beds. As a result, there is only a limited hydraulic connection between adjacent coal seams. The Tongue River Member can be conveniently divided into four main hydrogeologic units: Smith-Roland, Anderson-Dietz, Canyon-Wall, and Lower Tongue River Member.

3.4.1.3.2 (Continued)

The most significant of these geohydrologic units, the Anderson and Dietz coal seams and associated clinkers, form a continuous unit that extends from the Wolf Mountains on the west to the Tongue River on the east (see Figure 4.1.3-8 of Section 4.1.3, Volume IV, Part A). The combined Anderson and Dietz coal seams have a thickness of 60-100 feet. In the Wolf Mountains, the Anderson and Dietz coal seams are merged, but to the east the Anderson splits from the Dietz. Along Youngs Creek near the Crow Reservation border, the Anderson seam averages 20 feet in thickness, the Dietz seams averages 53 feet in thickness, and about 200 feet of inter-burden separates the seams. About 3 miles east of the Crow Reservation border, the seams merge to form a combined seam about 80 feet thick. Farther to the east, near the Tongue River, a thin seam called the Dietz No. 2 splits off from the combined Anderson-Dietz seam.

The western and southern extent of the Anderson-Dietz unit is defined by thick clinker beds that formed when the coal seams burned (see Figure 4.1.3-9 of Section 4.1.3, Volume IV, Part A). Some of the clinker beds are adjacent to the Anderson and Dietz coal seams, but many of the clinker beds found in the drainage basin of Little Youngs and Youngs creeks have been isolated by erosion.

Hence, it may be concluded that in the Site 23 area both the major ground-water aquifers - the alluvial deposits of the Squirrel, Youngs, Tanner, and Little Youngs Creek valleys, and Anderson and Dietz coal seams of the Tongue River Member and associated clinkers - form a more-or-less contin-uous groundwater unit from the Wolf Mountains on the west to the Tongue River on the east. The movement of both the surface water and ground-water is toward the Tongue River and external to the Crow Reservation. The potentiometric surface of the groundwater is also near ground surface levels.

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3.4.1.3.3 Water Quality

Water in the Bighorn River from St. Xavier to Bighorn is a calcium sulfate type. The water quality in the Bighorn River at St. Xavier is known to be better than the primary drinking water standards. However, EPA primary standards of 0.002 mg/l and 0.01 mg/l for mercury and selenium, respectively, have been exceeded at Hardin (see Table 4.1.3-8 of Section 4.1.3, Volume IV, Part A).

Several constituents have also exceeded the secondary drinking water standards at both St. Xavier and Hardin on the Bighorn River. For example, sulfate concentrations are seldom less than 250 mg/l and concentrations in excess of 400 mg/l are common.

Total dissolved solids (TDS) concentrations average in excess of 650 ppm, which is above the recommended 500 ppm value. The concentration of dissolved manganese also has exceeded the recommended standard of 0.05 ppm. Turbidity values in excess of 5 units have also been recorded. Nevertheless, it may be concluded that water in the Bighorn River on the reservation can, with proper treatment, be made acceptable for all uses, including drinking water supply, irrigation, livestock watering, industrial use, and wildlife resources.

The Tongue River is the major stream draining the Shell mining lease area and the candidate minemouth siting area designated as Site 23, since Squirrel, Youngs, Tanner, and Little Youngs creeks are all tributaries of the Tongue River as previously discussed. Surface water quality in the Tongue River Basin above the proposed project site is primarily affected by high-quality snowmelt from the Bighorn Mountains, by irrigation in Wyoming, and by surface water and groundwater inflow. Water quality in the Tongue River above the Tongue River Reservoir is generally good (see Table 4.1.3-9 of Section 4.1.3, Volume IV, Part A).

3.4.1.3.3 (Continued)

TDS concentrations, especially the concentrations of calcium, magnesium, sodium, bicarbonate, and sulfate, tend to increase downstream. The lowest concentrations of TDS, and of all major constituents, can be expected during the high-runoff months of May, June and July.

A comparison of these chemical analyses and other trace element analyses for the Tongue River above and below the project area indicate that applicable Wyoming and Montana water quality standards for the Tongue River in this area would be met. EPA Primary Drinking Water Standards are also met. EPA Secondary Drinking Water Standards for iron (500 mg/l), sulfate (250 mg/l), and iron and manganese (0.05 mg/l) are occasionally exceeded at the monitoring station near Decker. These waters are acceptable for most uses, including domestic supply and irrigation. The high hardness and bicarbonate values might require certain industrial users to provide treatment.

Generally speaking, the groundwaters available within the reservation are of poorer quality than the surface waters. The geologic profile of the reservation shows a considerable number of shale formations which are highly mineralized. Groundwater taken from the streambed alluvium (which represent most of the groundwater development) are reflective of the water quality in the stream but usually contain somewhat higher concentrations of dissolved minerals.

3.4.1.3 Physiography and Land Use

Site 1 is located in the northwestern portion of Big Horn County, Montana, in the unglaciated part of the Missouri Plateau section of the Great Plains physiographic province: The immediate area is characterized by hilly,

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3.4.1.3 (Continued)

gravel terraces, fans, and benches. The candidate site encompasses approximately 960 acres primarily used for agricultural activities at the present time. Elevations within the siting area range from approximately 3,200-3,4000 feet MSL.

Site 23 is located in an area of narrow stream valleys bordered by narrow, flat-topped plateaus on the eastern slop of the Wolf Mountains in the southeastern corner of the Crow Reservation. Elevations within the siting area range from approximately 4,100-4,300 feet MSL. Plant site boundaries tentatively encompass approximately 750 acres which are currently used as a grazing range for wildlife and domestic livestock.

3.4.1.5 Soils and Vegetation

Although the majority of Big Horn County is rangeland, the proposed Site 1 area is used primarily for raising wheat. Therefore, native vegetation is almost nonexistent within the boundaries of candidate Site 1. However, the known soil types can be used to identify range sites. This is possible because of the observed close relationship between plants, climate, and soils. The predominate soils at Site 1 occupy the Clayey range site, receiving 10-14 inches of precipitation annually. The soils are moderately deep to deep, granular clay loam, silty clay loam, silty clay, sand clay, and clay. Western wheatgrass, forbs, and green needlegrass are the predominant species. Other range sites encountered at candidate plant Site 1 are Shallow Clay, Dense Clay, and Pan Spots. Seven different soil series and 13 mapping units were found on candidate Site 1 (see Table 4.1.5-1 and Figure 4.1.5-1 of Section 4.1.5 and Appendix A-4 of Volume IV, Part A).

3.4.1.5 (Continued)

About 62 percent of candidate Site 23 is categorized as Clayey range site. Therefore, Site 23 is quite similar to Site 1 and contains 5 soils series and 7 mapping units (see Table 4.1.5-2, Figure 4.1.5-2, and Appendix A-4 of Volume IV, Part A).

Based on existing survey information, a very preliminary evaluation of possible vegetative types existing along the approximately 60-mile water pipeline traverse from the Bighorn River to Site 23 was conducted (see Section 4.1.5.2 of Volume IV, Part A). The route is situated in the transition zone between mixed praire grassland and eastern Montana ponderosa pine forest; therefore, it consists of a complex mixture of plant communities. Riparian vegetative types indicative of drainages traverse the area frequently. The Clayey areas are dominated by big sagebrush and the sandy areas by silver sage. The higher elevations with more precipitation consist of ponderosa pine and other trees (see Section 4.1.5.2 of Volume IV, Part A for a discussion of vegetation types or communities).

It is recommended that a range vegetation inventory be conducted for the eventual site and all utility corridors when the synfuels project proceeds to the next phase of development. The study should be conducted as part of the overall preoperational environmental program and should include mapping of vegetation types, identification and listing of species, and measurement of density composition, cover, and production.

3.4.1.6 Wildlife Resources

3.4.1.6.1 Site 1 (Including Ancillaries and Rights-of-Way

Information on the wildlife resources within the proposed areas of impact (see Figure 4.1.6-1 of Section 4.1.6, Volume IV, Part A) is limited to winter aerial surveys conducted by the U.S. Fish and Wildlife Service since

3.4.1.6.1 (Continued)

1979. Although various off-reservation studies of wildlife have been conducted, primarily on Westmoreland's lands (Tracts I, II, and III), no site-specific studies within the proposed area of impact for Site 1.

Possible large mammals could consist of the pronghorn antelope and white-tailed deer. Possible carnivores within the proposed Site 1 area of impact include the bobcat, coyote, red fox, badger, and striped skunk. Species of small mammals representative of the proposed project area include the white-tailed jackrabbit, desert cottontail, prairie dog, pocket gopher, and the more common ground squirrels, chipmunks, mice and rats.

Principal categories of birds occurring within the proposed area of impact are composed of upland game birds (sharp-tailed grouse, sage grouse, ring-necked pheasants), waterfowl and shorebirds, raptors, and passerine birds.

Possible threatened and endangered species in the Site 1 impact area could include the bald eagle, peregrine falcon, and black-footed ferret.

The major fisheries within the proposed project area are located along the Bighorn River and include brown and rainbow trout, and northern pike.

3.4.1.6.2 <u>Site 23 (Including Ancillaries and Rights-of-Way)</u>

The wildlife resources located within and immediately adjacent to the proposed area of impact (see Figure 4.1.6-1 of Section 4.1.6, Volume IV, Part A) vary significantly from those associated with Site 1 due, in part, to the diversity of habitat afforded by variations in topography and vegetation types characteristic of this area.

3.4.1.6.2 (Continued)

Although no site- and corridor-specific wildlife studies have been conducted, information collected since 1979 by VTN and others in conjunction with the proposed Crow/Shell coal lease provides baseline information for the general area of the proposed plant site. Likewise, additional data collected by the U.S. Fish and Wildlife Service since 1979 provide further information that serves as a basis for a general discussion of wildlife resources within the proposed impact area. Site-specific studies of the Site 23 area of impact would also be required, if that site becomes the final site selection and in the event the synfuels project proceeds to the next phase.

Major species of large mammals occurring within the general area indicate the presence of pronghorn antelope, mule deer, white-tailed deer, and an occasional elk.

Major species of carnivores occurring within the proposed project area include the coyote, lynx, bobcat, red fox, badger, longtail weasel, and the striped skunk.

Commonly occurring species within the Site 23 area are composed of the porcupine, red squirrel, white-tailed jackrabbit, desert cottontail, mountain cottontail, and numerous smaller rodents, including ground squirrels and mice.

Major categories of birds occurring within the Site 23 area include those listed for the Site 1 area; i.e., upland game birds, waterfowl and shorebirds, raptors, and passerine birds (see species list in Appendix A-2, Volume IV, Part A).

3.4.1.6.2 (Continued)

Amphibians occurring within the general area probably will be restricted to ponds, watercourses, and other water-associated areas. The following species have been documented as occurring within the general area of the proposed plant site: the painted turtle, tiger salamander, leopard frog, chorus frog, and the Plain's spadefoot toad.

Reptiles common within the general area of the proposed plant site include the bullsnake, praire rattlesnake, yellow-bellied racer, and three species of garter snakes. Common lizards include the northern sagebrush lizard and eastern shorthorned lizard.

Two species, the bald eagle and the peregrine falcon, listed as endangered under the provisions of the Endangered Species Act of 1973, have been documented as occurring within the Site 23 area of impact. The black-footed ferret occurs historically in association with black-tailed prairie dogs but its present status within this area remains unknown.

Principal fisheries within the general area of the plant site consist of the Youngs Creek and Squirrel Creek drainages. Species include brook trout, white sucker, mountain sucker, and lake chub.

3.4.1.7 Seismology

On the basis of a literature search conducted for this study, it may be concluded that the seismology of the Crow Reservation has never been comprehensively investigated. This is primarily due to the fact that no major seismic activity has been recorded on tribal lands as evidenced by the seismic risk map of the western United States (see Figure 4.1.7-1 of Section 4.1.7, Volume IV, Part A) which indicates the area encompassing the Crow Reservation as a Zone 1 (minimum risk, expected minor damage) earthquake risk area.

3.4.1.7 (Continued)

The nearest recorded earthquake (since 1904) to Site 1 occurred approximately 20 miles east of the proposed site and had a measured magnitude (Richter scale) of less than 3.99. Similarly, several minor earthquakes with a Richter magnitude of less than 3.99 have been recorded within 10-20 miles of Site 23 (see Figure 4.1.7-2 of Section 4.1.7, Volume IV, Part A).

As previously mentioned, the Site 1 location is bisected by a northeasterly-southeasterly trending fault approximately 5 miles in length. The geologic structure in this area is composed of Niobrara and Carlile members of the Cody Shale Formation of the Late Cretaceous Period (65-100 million years ago) and the structural displacement is inferred to be less than 100 feet. The fault cannot be classified as capable, although it is recommended that additional test drill data be developed to substantiate this premise if Site 1 becomes the eventual selected site for the synfuels facility.

No major faults are known to occur in the Site 23 area, although a major northeast trending fault is inferred to cross the extreme southeastern corner of the siting area.

3.4.1.8 Cultural Resources

The cultural resources of the Crow Reservation, although not totally documented, are reported to be quite extensive in certain areas. Hence, a more detailed site- and corridor-specific investigation and analyses will be required to more completely document the extent of the cultural resources within the proposed areas of impact. Basic information on the known archaeological and historic sites has been provided by the Montana State Historic Preservation Office and the BIA.

3.4.1.8 (Continued)

Recorded documentation list 46 sites consisting largely of occupational and buffalo jump sites. Other sites include rock cairns, tipi rings, fortifications, lithic scatters, surface stone quarries, workshops, and transient campsites. Five of the 45 documented sites of historic archaeological, and cultural significance are located within the immediate vicinity of Site 23. The remaining 41 sites are scattered within or adjacent to the proposed utility corridors. The potential for the occurrence of additional archaeological sites within or adjacent to Site 1 and throughout the unsurveyed portions of the proposed corridors is significant when considering past and recent discoveries within the general region.

Additionally, the Crow Tribe will continue to identify and preserve areas sacred to its tradition and culture. Two tribal land areas in the Bighorn and Pryor Mountains already have been designated in the Crow Land Use Zoning Ordinance in 1981. Therefore, consultation with Crow tribal members will be required to fully and adequately document the presence and extent of sites significant to the culture and tradition of the Crow people.

3.4.2 Jurisdictional Issues

The question of jurisdiction over energy development on Indian reservations is concerned with whether, and under what circumstances, various governmental entities (tribal, federal, state, and county) have the legal authority to impose regulation. Therefore, a number of jurisdictional issues that may arise in the construction and operation of a synfuels facility on the Crow Reservation have been identified.

This identification of issues and general principles is intended to promote planning of the facility in a manner that avoids jurisdictional conflicts, since there are ways in which the construction and operation of the facility

3.4.2 (Continued)

can be structured to minimize jurisdictional overlap. Such informed structuring should ultimately simplify the environmental review process by allowing clearer identification of those permits that are in fact necessary.

There appears to be no question that, in the vast majority of situations, federal environmental statutes can and will be applied to activities on Indian reservations. Several federal environmental statutes, such as the Federal Water Pollution Control Act, the Solid Waste Disposal Act, and the Surface Mining Control and Reclamation Act, are by their terms applicable to Indians or Indian lands. Others, such as the National Environmental Policy Act, make no specific mention of Indians or Indian lands.

Perhaps the most that can be said about the current law of state jurisdiction over reservation activities is that the question of state authority is subject to a sliding-scale analysis; i.e., the more exclusively "Indian" the activities sought to be regulated are, the less likely it is that a state may assert jurisdiction. Activities conducted exclusively by Indians on reservation lands enjoy the strongest protection from the exercise of state regulatory authority.

Two relatively clear principles emerge from the study analysis of jurisdictional issues. First, the federal government has pervasive authority to enforce federal statutes on reservations. Second, inherent tribal sovereignty should permit the application of tribal environmental statutes to Indians and non-Indians engaging in development activities anywhere on a reservation.

The applicability of state and county environmental regulations to activities on Indian reservations depends on a case-by-case analysis of facts, including the involvement of non-Indians in the activity, the location of

3.4.2 (Continued)

the activity, the relationship between attempted state or county regulations and federal regulatory schemes, and the effect of the attempted regulation on the tribe's right of self-government. Because such facts about the synfuels facility to be constructed on the Crow Reservation are not currently available, little basis exists for choosing which state or county regulations might apply.

3.4.3 Environmental Permitting

An evaluation of the existing regulatory framework for development of the synfuels project reveals both potential problems and opportunities. Without proper planning confusion, delay, duplication of effort, and inefficiencies may result as is common in large projects. In recent years, however, agencies at all levels of government have taken steps to improve coordination and facilitate permitting. Coordination of permit requirements and full participation by the Crow Tribe and federal, state, and local agencies offer the greatest opportunity for improving and expediting the permit process. The potential for environmental degradation through development of large-scale projects has resulted in the passage of a number of laws and regulations by tribal, federal, state, and local governments. Most of these regulations were developed independently, leading to conflicts, duplication, and overlap. Two or more levels of government may regulate the same aspects of the synfuels project using different standards, procedures, timing, and information requirements.

Therefore, an appropriate timing sequence in relation to other development activity has been synthesized to establish an overall frame work for scheduling major program elements associated with the environmental permitting process; i.e., prefeasibility study, feasibility analysis, decision to proceed with the project, environmental monitoring, NEPA process (preparation of EIS), environmental permitting process, and facility construction (see Figure 4.3-1 of Section 4.3, Volume IV, Part A).

3.4.3 (Continued)

Several major federal environmental permits and approvals will likely be required prior to construction or operation of the proposed synfuels project. Based upon legal research and extensive discussion with government agency staff, six major permits will probably be required for the synfuels project: (1) Prevention of Significant Deterioration (PSD) Permit: (2) 404 Dredge and Fill Permit; (3) National Pollutant Discharge Elimination System (NPDES) Permit; (4) Hazardous Waste Management Permit; (5) Underground Injection Control Permit; and (6) Coal Mining and Reclamation Permits. A detailed discussion of each permit; its applicability, the standards and conditions that apply; requirements for application; pertinent procedures; required lead time for approval; and statutory and regulatory authority are presented in Section 4.3.1, Volume IV, Part A.

Other potential nonpermit federal requirements that are related to environmental control are discussed in Section;n 4.3.1-7, Volume IV, Part A. A partial listing of other federal laws that may impact permitting of energy facilities on Indian lands which are not directly related to environmental protection but may require some environmental analysis and ultimately result in environmental conditions being made a part of any final approval or authorization, are also listed in Section 4.3.1-7 of Volume IV, Part A. The National Environmental Policy Act (NEPA), enacted in 1969, has been the most significant piece of legislation dealing with environmental matters. The most important feature of NEPA is that it requires all agencies of the federal government to prepare detailed Environmental Impact Statements (EIS) on major federal actions, programs, leases, projects, permits, etc., that significantly affect the quality of the human environment.

In most cases major energy projects on Indian lands will require an EIS. The federal agency that is designated as the lead agency responsible for the major action associated with the project is responsible for preparing the

3.4.3 (Continued)

EIS consistent with its own regulations and those promulgated by the President's Council on Environmental Quality (CEQ). For Indian lands, this agency is usually the Bureau of Indian Affairs. With respect to major environmental permit programs, the NPDES Permit, the 404 Dredge and Fill Permit, and the Coal Mining and Reclamation Permits are subject to both NEPA and the EIS requirements. The PSD Permit and the Hazardous Waste Management Permits are exempt from NEPA and the EIS requirements. The NPDES Permit is subject to NEPA and the EIS requirements if the permit is to be issued by EPA.

Fulfilling the federal NEPA requirements and preparation of an EIS can be a very time-consuming effort. Consistent with guidelines prepared by the CEQ, the requirements have been designed to assure full opportunity for review and participation by all interested parties. This open process exposes a project to a full range of public and political scrutiny as well as potential judicial attack. At a minimum, the time currently required to prepare an EIS is 18 months. However, large controversial projects could take significantly longer periods of time.

Tribal requirements are somewhat difficult to evaluate at present. The Crow Tribe has adopted an Environmental Health and Sanitation Ordinance which covers water supply, air quality, solid waste, and other health-related matters. However, this ordinance applies primarily to small-scale residential or community development. It is not yet designed to regulate environmental effects of large-scale industrial facilities. Additionally, some of the standards in the ordinance are inconsistent with current federal requirements.

The Crow Tribe has also adopted a Reclamation Code to govern surface mining of coal. Although the Crow Office of Reclamation is currently developing regulations and technical capabilities for administration, the code is not yet in force.

3.4.3 (Continued)

Large volumes of solid waste may result from the synfuels facility. Principally, these wastes will be ash discharged from the gasifiers and bottom ash, fly ash, and flue gas emission waste from the steam generators. It is anticipated that these wastes will be nonhazardous, thus not requiring a permit under Subtitle C of the Resource Conservation and Recovery Act. Even if certain wastes are considered hazardous under EPA regulations, only those wastes from the gasifiers would require a permit. The 1980 Amendments to RCRA defer regulation of fly ash, bottom ash, slag, and waste from flue gas emissions control generated primarily from combustion of coal or other fossil fuels until the completion of certain EPA studies. Future regulation is a possibility.

Regulation of nonhazardous solid waste under Subtitle D is left totally with the states and presumably to tribal governments. Section I, II, and IV of the Environmental Health and Sanitation Ordinance for the Crow Reservation relate to the permitting and licensing of business establishments and waste disposal facilities and may provide some authority and regulatory framework covering solid waste disposal from the synfuels facility. Clearly, however, this ordinance was not designed to address the type of solid waste problem associated with a coal gasification process.

In the absence of clear regulatory authority over nonhazardous solid waste disposal, the mitigation of possible environmental impacts can best be addressed through a complete analysis as a part of the Environmental Impact Statement process under NEPA.

As previously discussed, the applicability of state environmental regulations to activities on Indian reservations depends on a site-specific and development-specific analysis of facts. The analysis should explore the involvement of non-Indians in the development, the location of the development, the relationship between the attempted state regulation and

3.4.3 (Continued)

federal regulatory schemes, and the effect of the attempted regulation on the tribe's right of self-government. It is impossible at this stage of the project to predict with any accuracy which state regulations might apply. It must be emphasized, however, that the synfuels project is a major one that can create significant environmental as well as social and economic impacts and will generate considerable interest and perhaps direct involvement of state and local officials will be involved in the environmental permitting process to ensure that possible off-reservation impacts are addressed.

3.4.4 Regulatory Decision Schedule

A regulatory decision schedule requires the construction and combination of numerous elements. The procedures and deadlines set forth in statutes and regulations comprise the foundation. They are different for each permit, and in most cases, except for the PSD permit which has a statutory deadline of one year following the filing of a complete application, there is no limit on the timing for issuance. However, both the CEQ regulations governing the NEPA process and EPA permit regulations which include NPDES and hazardous waste permits, provide for the establishment of project decision schedules to encourage timely decision making. Additionally, agency policy and actual practice further delimit procedures and timing.

The regulatory decision schedule prepared for this study (see Figure 4.4-1 of Section 4.4, Volume IV, Part A) illustrates the close linkage of timing for the EIS and various permits. Because the EIS evaluates alternatives and may be a prerequisite to several federal decisions on the synfuels

3.4.4 (Continued)

project, it should be prepared as early as possible. An early start is also recommended since the EIS process is a lengthy one. Submission of applications for all required permits occurs, in the decision schedule, eight months after the EIS process begins.

The EIS process normally should be started well before permit applications are submitted. This allows preliminary evaluation of impacts and alternatives prior to commitment to specific permit options. Furthermore, under the decision schedule, the applicant submits permits prior to agency review of the preliminary draft EIS, allowing agencies to evaluate the permit application and the EIS together. The schedule assumes that no formal public hearings on permit application will be held until the final EIS has been prepared; the final EIS therefore serves as an important tool in the decision making process.

Preparation of a single EIS for the synfuels project, as shown in the decision schedule, is a prime area for consideration and increased efficiency in the review process. If a single EIS is used, the BIA would probably assume primary responsibility for preparation. Other federal agencies would work with BIA on a cooperative basis, rather than preparing their own EIS.

3.4.5 Residual Quantification

The major environmental residuals for two selected sets of synfuels plant designs are evaluated (see Section 4.5 of Volume IV, Part A) based upon an SNG production rate of 250 MM SCF/D and utilizing both Westmoreland and Shell coal feeds.

Since a zero discharge concept was applied to all wastewater associated with the operation of the proposed synfuels facility, major emphasis was placed on the quantification of plant gaseous and particulate emissions to

3.4.5 (Continued)

the atmosphere and the solids and/or solid-liquid mixtures resulting principally from the Flue Gas Desulfurization (FGD) system within the plant boiler operation and the ash from both the boiler operation and the Lurgi gasification plant.

The major gaseous emissions were developed by Fluor based on Westmoreland and Shell coal analyses as determined by Lurgi for the process design gasification balance. The results (see Table 4.5-1 of Section 4.5.1, Volume IV, Part A) indicate that the Case I design, reflecting a 250 MM SCF/D SNG plant producing power for internal needs only, employing Westmoreland coal, emits over 26 million tons/yr of gaseous effluents to the ambient atmosphere. CO_2 represents approximately 40 percent (about 10.5 million tons/yr) of the total annual emission. The Case II design, which reflect a 250 MM SCF/D SNG plant that generates electrical power in excess of internal requirements, assumes 40 percent weight percent coal fines are fed to the boiler emitting over twice the quantity of total gaseous effluent to the atmosphere (about 57-58 million tons/yr). Also, approximately 60 percent more CO_2 (about 16-16.5 million tons/yr) would be emitted on an annual basis. (Note: Case I of this evaluation is the same as the expanded Self-sufficiency Case; Case II represents both the expanded Base Case and the expanded Shell Coal Case.)

Preliminary annual estimates for 26 trace elements released as particulate matter to the ambient atmosphere were developed by CERT for the aforementioned Case I and Case II designs utilizing both Westmoreland and Shell coal feeds and representative trace element chemical analyses of both coals (see Table 4.5.1-2 of Section 4.5.1, Volume IV, Part A). Six of the trace elements-barium, manganese, strontium, vanadium, zinc, and zirconium resulted in annual particulate emission rates greater than 1,000 lb/yr, with barium, strontium, and zirconium all exceeding 20,000 lb/yr for the Case II design employing Westmoreland coal.

3.4.5 (Continued)

Preliminary annual estimates of the major solid residuals, consisting primarily of the ash from the Lurgi coal gasification units, bottom ash from the boilers, and sludge from the FGD unit were derived for the same Case I and Case II designs. The Case II design employing Shell coal resulted in the lowest annual solid waste inventory of approximately 572,000 tons, with the Westmoreland Case II design representing the largest annual inventory of slightly over one million tons, due principally to the higher sulfur and ash content of the Westmoreland coal (see Table 4.5.2-3 of Section 4.5.2, Volume IV, Part A).

3.4.6 Environmental Impacts Assessment

3.4.6.1 Air Quality Impacts Assessment

Since compliance with the Class I air quality PSD increments on the adjacent Northern Cheyenne Reservation presents a potentially serious environmental constraint to the siting of a coal gasification facility on the Crow Reservation, the preliminary screening of possible candidate plant sites by air quality dispersion modeling analysis became the early major driver for the entire feasibility study. The air quality dispersion modeling of eight possible candidate sites entailed use of the VALLEY model in the rural, short-term, complex terrain mode. That program can be invoked as an early predictive screening technique without the currently unavailable, site-specific climatological/meteorological data for the candidate sites on the Crow Reservation and the potentially sensitive pollutant locations on the nearby Northern Cheyenne Reservation. (See Section 4.6.1.1 of Volume IV, Part A). The preliminary screening analysis narrowed the number of sites to be considered for more detailed trade-off analysis in the overall siting evaluation study (Volume V) to four candidate sites. This was based upon current (1985-1990) BACT limitations for plant SO_2 emission

3.4.6.1 (Continued)

control efficiencies of 90 percent, vent gas incinerator SO_2 emission control efficiencies of 96 percent, and ESP particulate matter removal efficiencies of 99.7 percent. Two of the candidates, Sites 1 and 1A, are located in the west central area of the Crow Reservation. The other two candidate sites, 20 and 23, are located in the southeastern section of the reservation. Additional siting trade-off studies as discussed in Volume V further reduced the siting candidates to Site 1 and Site 23.

Since the basic process design developed by Fluor during the course of this study is predicated upon an SNG production rate of 125 MM SCF/D, the synfuels plant designs were expanded to reflect an ultimate plant production rate of 250 MM SCF/D in order to verify compliance of the two primary candidate sites with air quality Class I PSD on the nearby Northern Cheyenne Reservation.

In addition to confirming compliance with SO_2 and particulate matter Class I PSD increments for candidate Sites 1 and 23, the second phase of the air dispersion modeling investigated the implications of the GEP stack height regulations recently promulgated by EPA. Emphasis was placed upon SO_2 emission control efficiencies of greater than 98 percent for the Lurgi gasification plant, while state-of-the-art (BACT) technology for FGD systems for coal-fired boiler plants is presently vendor-guaranteed for 90 percent SO_2 emission control efficiencies. Additionally, the imposition of 99.4-99.7 percent removal efficiency for ESP in the designs to control particulate emissions within the EPA regulatory requirements for NSPS of 0.03 lb/MMBtu of heat released, drastically reduces the particulate emissions. Reduced emission loadings, coupled with the higher allowable 24-hour PSD increment of 10 ug/m^3 for particulated matter as compared to its SO_2 counterpart of 5 ug/m^3, has precluded serious air quality impacts due to plant particulate emissions at either Site 1 or Site 23 for the two design cases, in terms of compliance with Class I PSD requirements on the Northern Cheyenne Reservation.

3.4.6.1 (Continued)

As previously discussed, the Case I plant design (expanded Self-sufficency Case) assumes a production rate of 250 MM SCF/D SNG and generation of sufficient power for internal requirements only. The Case II plant design scenario (expanded Base Case and Shell Coal Case) produces 250 MM SCF/D of SNG utilizing the excess fines (40 percent) in the coal feed to produce additional marketable electrical power. Therefore, more stringent SO_2 emission control is necessary to preclude violations of the Class I air quality regulations for the Case II design scenario.

The sensitivity analyses performed for both Case I and Case II designs at Site 1 demonstrate that a physical stack height of 620 feet would meet the 24-hour SO_2 Class I PSD requirement for Case II, assuming baseline emission control efficiencies of 90 percent and 98.7 percent for boiler and vent gas incinerator emissions, respectively, and using a Westmoreland coal supply. The Case I design for a Westmoreland coal feed is relatively insensitive to change in stack height over the range of 350-650 feet and would achieve Class I PSD compliance for SO_2 emissions with the assumed baseline control efficiencies (90 percent) for the boiler plant over that range of values. Although it is not anticipated, the use of the Shell coal supply at Site 1 for the Case II design would result in a somewhat lower stack height than that for the Case II design for a Westmoreland coal feed. The Shell Case II design requires a stack height of 485 feet in order to comply with the 24-hour SO_2 Class I PSD increment at Site 1.

A review of possible vendors for FGD systems has indicated that one potential supplier has quoted an achievable upper limit (BACT) of 93.4 percent SO_2 emission control efficiency in the assumed 1985-1990 time frame for the final design and construction of the project. Upward adjustment of 90 percent SO_2 emission control efficiency to 93.4 percent for boiler emissions would effect a reduction of 100 feet in the minimum stack height requirement; i.e., from 620 feet to 520 feet for plant designs using Westmoreland coal supplies at Site 1. The above result and all subsequent results assume that the baseline SO_2 emission control efficiency for the vent gas incinerator retains a baseline value of 98.6 percent. From previously discussed results it has been shown that the Case II design using the Westmoreland coal supply establishes a possible future attainable limit for SO_2 Class I PSD compliance at Site 1 of 93.4 percent SO_2 emission control efficiency for the boiler emissions and a stack height of 520 feet. Therefore, assuming the slightly more conservative value of 525 feet for the plant stack height it logically flows that 93.4 percent SO_2 emission control efficiency would be required to comply with the 24-hour SO_2 Class I PSD increment. For the same set of initial assumptions, it is shown that 84.5 percent SO_2 emission control efficiencies would be required for Class I PSD for the Case I design at Site 1 using Westmoreland coal. Similarly, the use of Shell coal for the Case II design would, in turn, necessitate 82 percent SO_2 emission control efficiency at Site 1 to achieve the Class I PSD compliance.

The assumption of de minimus GEP stack height regulation crediting a 213 feet (65 m) allowance for modeling purposes does not affect any serious design constraints at Site 23 for the Case II design employing the Shell coal supply. Thus, an actual stack height of 213 feet could be utilized at Site 23 provided 76.3 percent boiler SO_2 emission control efficiency and a 98.6 percent vent gas incinerator SO_2 emission control efficiency are maintained. Since the BACT for boiler SO_2 emission control efficiency for the Case II design using the Shell Coal supply is 84 percent, it can be concluded that SO_2 Class I PSD compliance at Site 23 does not present a major potential environmental air quality impact or regulatory constraint for currently envisioned plant design (see Section 4.6.1.1.2 of Volume IV, Part A).

Since Billings, Montana, is currently a nonattainment area for particulates and a Class II designated air quality area for SO_2, these potential air quality impacts were evaluated for both Case I and Case II designs at

3.4.6.1 (Continued)

Site 1 for both Westmoreland and Shell coal supplies. The results of air quality dispersion analysis indicate compliance with the 24-hour SO_2 Class II air quality PSD increment at Billings for all the presently contemplated designs and coal supplies.

Assuming the aforementioned designs and coal supplies, the modeling analysis also indicates that the nonattainment status for particulate emissions at Billings would not be violated by operation of the proposed synfuels facility at Site 1.

As previously discussed, a similar dispersion modeling analysis of the potential impact of particulate matter emissions from the worst-case Case II design utilizing the Shell coal feed at Site 23 indicates compliance with the Class I PSD increment on the Northern Cheyenne Reservation, principally due to the stringent BACT invoked by the ESP with a 99.4 percent particulate matter removal. It is concluded that the major potential air quality impacts and, hence, possible Class I PSD noncompliance for particulates with respect to the Northern Cheyenne Reservation, could arise from fugitive dust emissions from the proposed Shell mining operation since Site 23 represents a potential mine-mouth siting opportunity. Therefore, strict control by properly implemented water spraying of the affected mining areas and adjacent access roads to reduce dusting from vehicular traffic and heavy mining equipment would be the primary mitigation measure. However, it must be recognized that Class I regulatory compliance in this instance would be the responsibility of Shell as the mine operator.

Thus, it can be concluded that the exceptional SO_2 emission control efficiencies (greater than or equal to 98.6 percent) believed to be attainable from the Claus, SCOT, and Stretford gas purification units within the Lurgi gasification process design (see Section 4.6.1.2 of Volume IV, Part A) are a major reason that the designs, particularly Case II with a Westmoreland feed at Site 1, are able to comply with Class I PSD requirements on the Northern Cheyenne Reservation.

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3.4.6.1 (Continued)

Additionally, using special burners within the vent gas incinerators to limit NO_x and hydrocarbon gaseous emissions from the gasification plant reduces the potential air quality adverse impacts from the pollutants. NO_x reduction is particularly significant, since NO_x and particulate matter are known to be the major contributors to visibility degradation from coal combustion processes (see Tables 4.6.1-8 and 4.6.1-9, Section 4.6.1, Volume IV, Part A).

3.4.6.2 Water Resources Impact Assessment

3.4.6.2.1 Water Quantity Impacts Assessment

The presently contemplated withdrawal of 14,000 gpm (approximately 20,000 ac-ft/yr) from the Bighorn River to accommodate the water requirements for the expanded 250 MM SCF/D SNG synfuels facility constitutes the only potential water quantity impact to the Crow Reservation resulting from the proposed project. Since a water withdrawal rate of 20,000 ac-ft/yr constitutes only about 1 percent of the average flow rate in potential withdrawal for the synfuels project use, the potential environmental water quantity impact is considered minimal (see Figure 4.1.3-2 of Section 4.1.3, Volume IV, Part A).

3.4.6.2.2 Water Quality Impacts Assessment

Since the engineering design of the facility is predicated upon zero liquid discharge; i.e., having no direct discharge of liquid waste effluents to surface waters or groundwaters within the areas of the two selected candidate sites, Site 1 and Site 23, potential adverse water quality impacts to the Crow Reservation and the surrounding environs from the operation of the proposed synfuels facility are closely interrelated to the mitigation of

3.4.6.2.2 (Continued)

the liquids and solids process waste residue. Hence, the major mitigation measures to preclude potential water quality impacts evolve quite naturally around the basic design of the synfuels plant process water management system irrespective of the siting area (see Figure 4.6.2-1 of Section 4.6.2.2, Volume IV, Part A).

The capability of water soluble ions or compounds to migrate or to be transported externally from the immediate area of either plant site is dependent on (1) their increased mobility in liquid (aqueous) state, and (2) a continuous transport linkage, the liquid pathway in this instance, to an area of potential environmental impact.

Therefore, the ancillary containment features incorporated into the design of the liquid-solid, and solid process waste effluents systems constitute the primary mitigation measure necessary to prevent liquid contaminant migration into either surface waters or groundwaters.

All potentially hazardous process liquid waste effluents for the synfuels plant are stored in a series of ponds located within the completely fenced plant siting area thereby precluding entry by ambulatory wildlife (Section 4.6.2.2 of Volume IV, Part A). The largest of the ponds and recipient of the majority of process liquid wastes, the solar evaporation pond, effectively incorporates a multilayer containment barrier comprised of two relatively impervious lining materials, High Density Polyethylene (HDPE) and clay.

The other smaller repositories of liquid waste effluents, e.g., the wastewater equalization pond, the treated effluent pond, the diversion box and pond, and the oily stormwater pond, also incorporate this lining system design (see Figures 4.6.2-2 through 4.6.2-8 of Section 4.6.2.2, Volume IV, Part A).

3.4.6.2.2. (Continued)

Additional mitigation measures incorporated in the pond design include design provisions for adequate freeboard and pond embankment side slope to preclude potential surface runoff of the stored, liquid waste effluents as a consequence of natural occurrences such as tornadoes, heavy storms, or floods. Provisions for leakage detection are also included in pond design for all the liquid waste storage repositories should the integrity of the lining system be circumvented for any reason. The leakage detection system for the ponds is designed to allow plant operators a means of detecting any failures in the pond lining system and adequate time to employ corrective measures prior to the development of a potentially adverse environmental water quality impact.

Thus, it may be concluded that under normal plant operating conditions and barring the occurrence of any catastrophic natural events (earthquakes, floods, tornadoes, etc.), the engineered containment design of liquid waste repositories for the synfuels plant should prevent any major potentially adverse environmental impacts to the water quality of the Crow Reservation and the area adjacent to the reservation.

However, it must be recognized that an ion material balance was not conducted as part of this feasibility study for the major and trace liquid constituents comprising the liquid waste streams. Hence, detailed identification and characterization of the process liquid waste stream constituents is not now possible. It is, therefore, recommended that if the synfuels plant proceeds to the next phase, process liquid waste stream characterizations should be evaluated in order to substantiate the long-term capability of the proposed multilayer liner system to contain the identifiable constituents comprising the liquid wastes.

3.4.6.3 Solid Waste Disposal Impact Assessment

A similar containment design approach to the liquid waste disposal system has been developed for solids waste disposal for the proposed synfuels plant. Since the quantities of solid wastes for a coal gasification plant are considerably more extensive than liquid wastes and the repositories are located outside the plant site boundaries, potentially more serious environmental water quality impacts could arise.

The synfuels plant will produce a variety of solid wastes for disposal. The majority of the wastes consist of ash from the Lurgi coal gasification units, ash from the boilers, and sludge from the FGD unit. Other solid wastes from the plant include water treatment sludges, spent catalysts, and general plant refuse. It is recommended that general plant refuse should be at least qualitatively inspected prior to disposal at a local public waste disposal site to make certain that potentially hazardous process wastes are not inadvertently comingled. The quantification and environmental impact evaluation of the spent catalysts could not be adequately assessed in this feasibility study due to a lack of proprietary information concerning their physical and chemical properties.

The proposed solid waste disposal plan developed by Fluor as the Base Case for this study is specific for Site 1 and assuming Westmoreland coal feed. The ash and other solid wastes will be stored adjacent to the synfuels plant battery limits since ash disposal at the existing Westmoreland Absaloka mine is not an economical option as discussed in Volume V of this report (see Figure 4.6.3-1, Section 4.6.3, Volume IV, Part A). For the alternate Shell Coal Case at Site 23, the ash will be returned to the proposed Shell mine for disposal.

The worst-case, Case II (expanded Base Case), employs the Westmoreland coal at the proposed expanded production rate of 250 MM SCF/D and producing additional electrical power above that required for internal plant consumption. It produces 0.977 million cubic yards of major solid waste

3.4.6.3 (Continued)

effluents annually, or 24.4 million cubic yards of solid waste over a 25-year plant operating life. Similarly, the 125 MM SCF/D Case IIA design counterpart (Base Case) of Case II produces approximately one-half of the volume of solid wastes, i.e., 0.489 million cubic yards per year or 12.2 million cubic yards in the 25-year plant operating lifetime. About 55.48 percent of the solid waste volume for the design Case II and IIA using Westmoreland coal results from gasifier ash from the Lurgi process. Ash and FGD sludges from the boiler operation represent about 28.25 percent and 16.27 percent, respectively, of the total solid waste volume both annually and cumulatively over 25 years. The design Case IA (125 MM SCF/D SNG) represents the lowest solid waste volume requirement for the designs using a Westmoreland coal feed. Solid waste volumes of 0.710 million cubic yards over 25 years are evidenced for design Case IA, with gasifier ash representing about 76.5 percent of the total solid waste volume. This result arises from the reduced requirement for the boilers, since the plant is designed to produce only enough power for internal facility needs. (Self-sufficiency Case.)

A more realistic overall plan for long-term synfuels plant operation is represented by Case III which assumes cumulative 25-year solid waste volumes based upon a 5-year operation at the Case IIA design level (125 MM SCF/D SNG) followed by a 20-year operation of the expanded Case II plant design. Using excess coal fines to produce additional electrical power for sale represents a more economically viable plant operation than other options evaluated in this feasibility study as discussed in Volume II.

Case III results in a 25-year solid waste volume commitment of approximately 22 million cubic yards using a Westmoreland coal supply with about 55.4 percent of the total solid waste resulting from Lurgi gasifier ash. Case designs IIA and II, employing the Shell coal feed require considerably

3.4.6.3 (Continued)

less solid waste disposal volume requirements principally due to lower ash content and also lower sulfur content of the Shell coal resulting in lower SO_2 emission control requirements (84 percent vs 90 percent) and, hence, less FGD sludge production for disposal.

Shell coal feed Cases IIA and II require solid waste disposal volumes of 0.282 million cubic yards and 0.565 million cubic yards, respectively, on an annual basis; and 7.562 million cubic yards and 14.125 million cubic yards, respectively, over an assumed 25-year plant operating period for the Shell coal design Cases IIA and II (see Table 4.6.3-1 of Section 4.6.3.1, Volume IV, Part A).

The solids waste disposal facility at Site 1 is designed for complete containment or isolation of the solid wastes by encapsulation with 5 feet of clay. Thus, any potential water quality impacts must be predicated upon either (1) transport of aqueous anions or cations derived from solubilized solid wastes through the clay liner; (2) fairly extensive fracturing of that liner due to some catastrophic natural event such as an earthquake, flood, etc.; or (3) improper liner preparation and construction procedures, thereby creating the necessary transport pathway for possible solid waste contaminants to nearby surface waters or possibly groundwater aquifers.

The clay liners will be specifically designed to have a permeability of 10^{-7} cm/sec or less considering natural penetration through a 5-ft liner thickness as set forth in RCRA regulations. Therefore, it would require more than 48 years under normal gravitational hydrostatic pressures for a possible aqueous contaminant to penetrate the liner.

The introduction of hydrostatic head forces can be precluded by assuring that neither the natural drainages or flooding conditions will result in drainage into the solid waste disposal facility area--a factor accounted for in the Site 1 solid waste facility design.

3.4.6.3 (Continued)

Unquenched ash samples from the Lurgi gasification tests of representative samples of both Westmoreland and Shell coals were subjected to two separate types of leachate tests. Analysis of leachate indicates that potential contaminant concentrations do not exceed the limits for hazardous wastes as now defined by EPA. However, due to the technical complexity of the leachability of solids waste residues when acted upon by water at a land disposal area, the understanding of the possible long-term physico-chemical processes is presently incomplete. Therefore, it is recommended that a thorough evaluation of the characteristics of these solid wastes be made prior to the construction phase of the proposed synfuels project (see Section 4.6.3.3 of Volume IV, Part A).

Additionally, the natural geohydrologic environment of the Site 1 area lends itself to mitigation of any potentially adverse water quality impacts from either solid or liquid process waste residues.

As previously discussed, the geology of the Site 1 area indicates that stiff clays predominate over hard claystone bedrock at depths of 3-7 ft. The clays are silty, sandy, calcareous, and occasionally porous. The claystone bedrock is slightly sandy and contains scattered bentonitic clay lenses. The bedrock consists primarily of the Niobrara and Carlile shale members of the Colorado Group of the Cody Shale Formation of the Upper Cretaceous series. Preliminary test borings indicate that these clays and claystone bedrock expand when wetted indicating both relatively high natural impermeability and low, unsaturated interstitial pore volumes--natural conditions highly suited to the mitigation of aqueous contaminants (see Section 4.1.2 of Volume IV, Part A).

3.4.6.3 (Continued)

Preliminary test borings in the Site 1 area have indicated no free water in any of the test holes. Hence, water quality impacts to groundwater aquifers by seepage should have little effect on any near-surface construction such as a solid waste disposal facility. Additionally, surface water drainage and evaporation should be limited to the overburden section above the clay cap of the disposal area (see Section 4.1.3 of Volume IV, Part A).

Although the process solid wastes would most likely be returned from Site 23 to the proposed Shell mining area for disposal, it is proposed that a similar isolation or containment design approach to solid waste disposal developed for Site 1 be applied as well at Site 23. In fact, perusal of the possible natural geohydrologic environmental setting at Site 23 dictates a possibly greater need for assurance of complete containment of the solid wastes at Site 23 to minimize adverse water quality impacts.

As previously inferred, the major groundwater aquifers--the alluvial deposits of the Squirrel, Youngs, Tanner, and Little Youngs Creek valleys, and Anderson and Dietz coal seams of the Tongue River member and associated clinkers--form a more or less continuous groundwater unit from the Wolf Mountains on the west to the Tongue River on the east. The movement of both the surface water and the groundwater is toward the Tongue River and outside the Crow Reservation. The potentiometric surface of the groundwater is also near ground surface levels (see Section 4.1.3 of Volume IV, Part A).

Hence, the possibility could exist for a nearly continuous transport path for aqueous contaminants from synfuels plant process liquids and solid residues if the proposed isolation or containment liners are circumvented for any reason in the Shell mine Site 23 area. Therefore, additional precautions must be taken in the site selection, design, and construction

3.4.6.3 (Continued)

of the disposal areas--especially the solids waste facility--in the Shell mining area to make certain that (1) the waste disposal containment liners are capable of high, long-term integrity, and (2) continuous aqueous contaminant surface water or groundwater pathways are not possible in the waste disposal area in order to preclude any adverse water quality impacts to the Tongue River drainage system.

Regardless of the siting area, it is recommended that thorough preoperational and operational groundwater monitoring programs be established at both the plant site in the vicinity of the proposed liquid waste storage area and at any solid waste disposal area.

3.4.6.4 Preliminary Wildlife Resource Impact Assessment

Approximately 960 acres will be utilized for the proposed Crow synfuels facility at Site 1; another 290 acres will be required for access roads, railroads, and water pipeline; and an additional 300-600 acres will be allocated to a solids waste disposal site. Thus, approximately 1,250 acres will be required for the project at Site 1 (see Figure 4.6.4-1 of Section 4.6.4, Volume IV, Part A).

Wildlife habitat within these proposed sites could be considered lost for the duration of the project. Terrestrial wildlife with limited mobility and small home range sizes will be most affected. Sharp-tailed grouse are known to be quite abundant within the general area and loss of habitat will directly impact those populations.

Disturbances associated with the site preparation and construction processes could impact pronghorn antelope and sharp-tailed grouse depending on the timing of construction activities. Uncontrolled access and activities

3.4.6.4 (Continued)

could result in further disturbance, harassment, and poaching, thereby directly impacting wildlife populations particularly during winter months when populations such as pronghorn antelope and sharp-tailed grouse are concentrated.

Preliminary plant layout indicates that approximately 1,440 acres will be required for Site 23. Plant site boundaries tentatively encompass approximately 750 acres. Approximately sixty miles of pipeline will be required to transport necessary water to the plant site. Access roads as proposed will cover approximately 27 miles. Therefore, total surface acres required for both the access roads and pipeline is about 690 acres. Therefore, a total of 1,440 acres of wildlife habitat could be considered lost for the duration of the project. Since the solid waste would be disposed in the Shell mining area, land. disturbance would have occurred prior to any activities associated with the synfuels project.

The proposed plant Site 23 lies within a major pronghorn antelope winter range with plant boundaries overlapping or lying directly adjacent to critical-use areas. Construction activities could seriously impact these animals depending on the time of activities (see Figure 4.6.4-2, Section 4.6.4.2, Volume IV, Part A). Movements of antelope from the lower portions of the winter range to the upper northwest sections could be disrupted. Birthing activities of pronghorn antelope and mule deer could also be disrupted resulting in lowered reproductive success. Golden eagles and prairie falcons are also known to nest within close proximity to the plant site; therefore, any disturbance during nesting season could result in abandonment of the area.

3.4.6.4 (Continued)

Although activities associated with access road and pipeline construction will be temporary, impacts could be significant if these activities transpire during critical life-cycle periods for indigenous wildlife. Since access roads and pipelines will cross known mule deer, white-tailed deer, and elk ranges, uncontrolled access during construction activities could result in poaching and further harassments, particularly in more remote areas.

It is further recommended that water intake structures on the Bighorn River be designed to reduce potential fish losses due to impingement.

In the Site 1 area water quality degradation of Fly Creek and Two Leggins Creek could increase if measures are not taken to contain runoff and resultant sediment loads. Depending on the quality of additional sediment resulting from construction activities, impacts to the Bighorn River fisheries could result. Similarly, in the vicinity of the Site 23 area, increased siltation of Youngs and Dry creeks and, consequently, the Tongue River could occur if measures are not taken to minimize or contain runoff from disturbed sites. The already low populations of brook trout in the upper reaches of Youngs and Dry creeks could be essentially eliminated if excessive siltation occurs. Likewise, the Owl Creek and Little Bighorn River fisheries could be impacted if excessive siltation occurs. Hence, strict procedural control during site preparation and construction activities is recommended to mitigate this potential impact.

3.4.6.5 Utility Corridors: Environmental Considerations

Some of the major concerns with ecological impacts of utility line corridors center on the management of the corridor. Herbicides have been used extensively in the past to maintain a clear right-of-way. This practice

3.4.6.5 (Continued)

resulted in the loss of vegetation and, hence, carrying capacity. Thus, it is recommended that use of herbicides should either be avoided or strictly controlled. On the other hand, the areas relatively clear of overstory vegetation frequently have a good diversity of shrub vegetation and other understory vegetation. This, in turn, maintains a more diverse food web than the forest alone. Thus, the cleared right-of-way maintains an ecotone and introduces increased species diversity along the corridor if properly managed. Therefore, it is recommended that the ecology of the utility corridors be examined in greater detail after final site selection to reduce the potential impacts on the regional ecosystem. Since the length of the water pipeline corridor is considerably more extensive for Site 23, the potential for possible environmental impacts to both vegetation and wildlife are concomitantly greater. It must be emphasized, however, that over the long term, the most important mitigation measure with respect to utility corridors is to maintain the vegetation and, thus, the carrying capacity for wildlife.

3.4.6.6 Preliminary Cultural Resources Impact Assessment

Since the extent of cultural resources for much of the Crow Reservation, including the proposed candidate plant sites and areas of impacts, is largely unknown, it becomes difficult to adequately assess the cultural or archaeological impacts for the proposed project. However, cultural resources are vulnerable to impacts from surface and subsurface disturbance and from intrusion into previously inaccessible and remote areas.

Construction activities could totally destroy buried deposits if adequate and required archaeological clearances are not obtained. Increased human access to previously remote areas could enhance the potential for vandalism and theft at cultural sites. Valuable information important to the

3.4.6.6 (Continued)

understanding of prehistoric and historic events could be lost or destroyed. Religious and sacred sites important to the Crow tradition could also be impacted. Compliance with all tribal, state, and federal rules, regulations, codes, orders, and proclamations will be required to adequately mitigate any potentially adverse impacts.

3.4.6.7 Potential Impacts from Radioactive Trace Elements in Coal

Trace concentrations of uranium and thorium obtained from representative samples of both the Westmoreland and Shell coals (see Section 4.5 of Volume IV, Part A) have been previously quantified in terms of their content within particulate matter emitted to the atmosphere.

Using these emission rates as source terms for the air dispersion modeling analysis indicates that considerably less than 0.1 ug/m^3 of either uranium-238 or thorium-232 would be the maximum concentrations at selected locations on the Northern Cheyenne Reservation from a Case II design located at either Site 1 or Site 23.

Several selected references have estimated (see Section 4.6.7 of Volume IV, Part A) that approximately 90 percent of the uranium content in the coal feed for a power plant terminates in the solid ash residues. Based upon 90 percent uranium retention in the solid wastes for the proposed synfuels facility, approximately 4.6 curies/yr of U-238 would accumulate in the solid waste facility for worst-case Case II design. It is recommended that potential radionuclide inventories, particularly in the solid wastes, be more thoroughly investigated if the Crow Synfuels Project proceeds beyond the stage of this feasibility study.

3.4.7 Environmental Monitoring Requirements

Requirements for detailed, site-specific baseline environmental monitoring data constitute an essential facet of the synfuels feasibility study and are outlined in a preliminary manner for both air and water quality. These preoperational monitoring programs must be started at least one year prior to the initiation of the environmental permitting process and, consequently, impact both the regulatory decision-making schedule and the overall synfuels project schedule.

3.5 HEALTH AND SAFETY

This health and safety assessment is developed in support of the Crow Tribe of Indians Synfuels Feasibility Study. The proposed plant is a complete "grass roots" facility for the conversion of coal into consumer energy products, primarily pipeline quality substitute natural gas (SNG), and possible electrical power for export. Coal from the Westmoreland Mine or proposed Shell Mine and raw water from the Bighorn River are the only natural resource materials used in the plant.

The plant uses the best available control technology (BACT) to protect the local environment. Particulate matter and sulfur oxides are removed from flue gases; coal dust is contained within closed conveying and storage systems. The plant water management system is designed to achieve zero effluent discharge. Solid waste from the plant is made suitable for safe disposal as landfill. Mechanical equipment is designed for low noise operation to maintain the relatively quiet local environment.

The proposed plant is in the preliminary stage of development: therefore, this assessment is limited to providing a basis for control strategies. It is premature to list specific control methods since equipment, operating procedures, and staff organization are not formalized.

The objective of this health and safety assessment is to provide necessary information for consideration in the engineering design of the proposed synfuels plant. By effectively reducing the potential hazards to workers in the early stages of plant design and development, the risk of adverse health and safety effects can be substantially lowered. This is a worthwhile objective benefiting both plant personnel and the owners. Benefits to the owners are reduced liability with correspondingly reduced insurance premiums; higher productivity arising from fewer plant shutdowns, lower absenteeism and labor turnover rates; and decreased medical and health care cost due to less injury and illness.

This assessment is based on a review of the Process Design Bases prepared by Fluor, and technical information in the literature. The relevant information regarding occupational health and safety is largely based on experience with other synfuel commercial and pilot plants. Relevant information is also derived from operating records of process units similar to those of the proposed plant such as the ones currently operating in petroleum refineries. The major potential health and safety hazards include toxic gases, potential carcinogenic substances, and harmful physical agents. However, these potential hazards can be effectively mitigated by engineered controls and work practices.

All occupational health and safety regulations and guidelines applicable to the proposed plant are reviewed. Federal Occupational Safety and Health Administration (OSHA) standards are the only regulatory requirements pertinent to this project with regard to occupational health and safety. There are also recommendations, guidelines, codes and standards developed by government and industrial organizations which are taken into account in this assessment. These guidelines by the National Institute for Occupational Safety and Health (NIOSH) are discussed in this report.

Another input to the assessment is a review of the available health and safety data base. Potential health and safety hazards are identified according to the various process units of the plant. The hazards include risks of inhalation, skin absorption, or possibly ingestion of hazardous chemicals and contaminants, exposures to harmful physical agents such as radiation or noise, and injuries due to accidents. These risks can occur during a plant upset, leak, spill, or during maintenance.

3.5 (Continued)

There are basically three elements essential to control of occupational hazards. These are:

(1) Engineered controls which directly impact the design and/or operation of the plant.

(2) Work practices including administrative controls which provide additional protection when engineered controls are not adequate or feasible and which are generally based on prior experience and subjective judgment.

(3) Personal protective equipment and clothing which are used when neither engineered controls nor work practices provide acceptable protection to compliance levels.

Health and safety engineered controls are discussed and summarized in terms of design considerations and plant layout. Design considerations include: (a) maintenance and repair; (b) valves; (c) seals; (d) flanges; (e) pressure vessels; (f) process lines; (g) drains and sumps; (h) process sampling; and (1) hot surfaces.

A carefully designed plant layout (plot plan) can provide intrinsic health and safety protection by methods such as segregating high risk process units and providing adequate workspace for unencumbered maintenance, repair, and operations. Prevention of losses or leaks of toxic materials can be incorporated into the plan by collectively considering the demands of process design, construction of the facility, normal operation, maintenance, repair, process sampling, personal welfare, and potential emergency situations.

3.5 (Continued)

Work practices, cover special procedures, administrative controls, personal protective clothing and equipment, and medical surveillance and monitoring.

Special procedures include all of the procedures that govern work practices in the plant. They are intended to prevent or reduce the levels of health and safety risks to which employees may become exposed. In addition to specific procedures typical to coal gasification plants, they include general practices employed in industry, particularly in petroleum refineries and the chemical industry.

Also included are the training of employees to become knowledgeable about the nature of plant hazards and safety provisions available to protect themselves.

Administrative controls are primarily measures and procedures which control and record the movement of visitors, workers, materials, and equipment into and through the plant area. Their purpose is to reduce health and safety risks to both employees and visitors.

Provision and proper employment of personal protective equipment and clothing in synfuel plants help to prevent the exposure or reduce the adverse health effects of worker exposure to hazardous materials. Included are work clothing, gloves and footwear, respiratory protection, hearing protection, and other protective equipment for special situations.

Control monitoring and medical surveillance are not strictly techniques used for reducing worker exposure to hazardous materials. Yet they are critical to the entire control effort because they verify the effectiveness of controls, detect and assess exposures to hazardous materials at an early stage.

3.5 (Continued)

Successful programs to prevent and cope with health and safety hazards in a plant also include emergency plans. These are prepared to reduce response time and thus prevent a smaller emergency from developing into a more serious one, and to optimize response. Emergency plans cover such emergencies as construction and transportation accidents, fires, explosions, release of and exposure to toxic chemicals.

3.6 SOCIOECONOMIC

3.6.1 SUMMARY

The socioeconomic impacts of the synfuels plant were analyzed by modifying the "state-of-practice" framework to reflect the most recent improvements in state-of-the-art forecasting methods. The analysis begins with an evaluation of the manpower requirements arising from the construction and operation of the facility. To obviate the problems associated with the use of point estimates of construction manpower demand, the cases were developed to provide a range of employment needs.*

Following the estimation of the annual "peak" and "average" construction, plant operation, mine operation, and secondary employment requirements, the availability of local Crow and non-Crow workers with appropriate skills to fill these jobs was analyzed for Site 1 and Site 23. As a part of this analysis, estimates were made of the number of jobs that would be taken, by year, by the Crow work force; the numbers of jobs likely to be filled by non-Crow workers residing within commuting distance of Site 1 and Site 23; and the numbers of workers that would have to in-migrate to these sites to fill the remaining construction, operating, and secondary positions.

The estimates of the annual in-migrating work force provided the foundation for assessing the population impacts that the synfuels plant would have on the communities within commuting distance of Site 1 and Site 23. The number of newcomers (in-migrating workers and their household members) to

*The use of the cases to describe a range of manpower needs was incorporated to account for revised employment levels during the construction and operation phases that occurred after the socioeconomic analysis was nearly completed. These estimates are presented in Appendix C-4 of Volume IV.

3.6.1 (Continued)

both sites were estimated for both the peak and average employment requirements. In addition to the number of dependents in each in-migrating household, estimates were made of the number of potential secondary workers likely to be provided by each of these households.

Given the impact on the populations of communities in the Site 1 and Site 23 areas, estimates were constructed of the impacts these newcomers would place on the demands for increased public and private facilities and services. From these figures, estimates were prepared of the likelihood that project-related growth would "pay its own way" in each of the areas. This involved comparing the estimates of the increased capital and operating costs of new populations to the estimates of incremental public revenues contributed by the newcomers.

3.6.2 EMPLOYMENT EFFECTS

The direct and secondary work force requirements associated with the peak cases for constructing and operating the synfuels plant and expanding nearby coal production facilities are summarized in Table 3.6.2-1. Omitted in this summary table are the differences in the skill requirements of these workers. These differences were explicity considered in the supporting analyses of labor requirements and availability. As the table illustrates, the total employment requirements associated with the synfuels plant rise rapidly to a peak near the end of the plant construction period. In succeeding years, the employment requirements quickly stabilize at a level roughly one-third of that expected in 1988.

The availability of local workers to fill these positions without having to change their residences was estimated by analyzing the number of Crow and non-Crow workers with the required skills at each site. Table 3.6.2-2 presents the estimates of the number of jobs filled by local workers under the peak employment case.

TABLE 3.6.2-1

SUMMARY OF EMPLOYMENT REQUIREMENTS

Number of Workers

Year	Plant Construction	Plant Operations	Mine Production	Local Secondary	Annual Totals
1985	793			141	934
1986	2260			435	2695
1987	3350			706	4056
1988	3503			816	4319
1989		750	180	567	1497
1990		750	180	511	1441
1991		750	180	480	1410
1992		750	180	464	1394
1993		750	180	464	1394
1994		750	180	464	1394
1995[a]		750	180	464	1394

[a]The employment figures for following years should be the same as for 1995.

TABLE 3.6.2-2

NUMBER OF POSITIONS FILLED BY LOCAL EMPLOYEES AT EACH SITE

	Site 1					Site 23				
	Construction		Operation		Secondary	Construction		Operation		Secondary
	Crow	Non	Crow	Non	Total	Crow	Non	Crow	Non	Total
1985	324	321		90	141	324	32			108
1986	385	1193		90	435	385	33			208
1987	385	1192		90	706	385	103			534
1988	384	972		90	816	384	57			734
1989			264	90	567			264	90	567
1990			264	90	511			264	90	256
1991			264	90	480			264	90	320
1992			264	90	464			264	90	307
1993			264	90	464			264	90	307
1994			264	90	464			264	90	307

3.6.2 (Continued)

In constructing these estimates, it was assumed that the Crow workers possessing the necessary skills would be given preference in hiring. It was also assumed that the Crow workers with experience as construction laborers would be permitted to qualify for apprenticeship positions if too few "laborer" positions were available to accommodate them. Finally, it was assumed that as many as 174 Crow workers would qualify for plant operating jobs if an intensive 18-month training program were instituted prior to the completion of plant construction.

3.6.3 Population Effects

Given the estimates of the availability of local workers to fill the jobs created at Site 1 and Site 23, the number of in-migrating workers needed to fill the remaining positions was determined. Assuming that the average number of dependents per in-migrating construction worker household would be approximately 1.9 and that other in-migrating workers would have household sizes roughly equivalent to those of existing residents, the population effects of the Site 1 and Site 23 in-migration work forces were estimated. The results-for the peak employment case-are summarized in Table 3.6.3-1.

Although Billings (Yellowstone County) is approximately 20 highway miles farther than Hardin from Site 1 (Big Horn County), it is assumed - based on recently acquired evidence from the Denver Research Institute's retrospective study of energy impacted communities - that the vast majority of in-migrating families will choose to live in and around Billings because of its size, amenities, and housing. The table reflects the effects of assuming that 90 percent of the newcomers to the Site 1 facility choose to live in or near Billings in Yellowstone County. As indicated, the relative population effects (the population of both counties made up of project-related newcomers) in

TABLE 3.6.3-1

ESTIMATED POPULATION INCREASES AT SITES 1 AND 23

	Site 1 Counties				Site 23 Counties	
	Big Horn		Yellowstone		Sheridan	
Year	No.	%	No.	%	No.	%
1985	28	0.23	253	0.21	907	3.3
1986	130	1.07	1166	0.96	4103	14.6
1987	337	2.73	3032	2.44	5957	20.6
1988	407	3.25	3665	2.90	6093	20.6
1989	181	1.42	1628	1.26	2242	7.4
1990	181	1.40	1628	1.24	2375	7.7
1991	181	1.38	1628	1.22	2161	6.9
1992	181	1.36	1628	1.20	2162	6.8
1993	181	1.34	1628	1.19	2162	6.7
1994	181	1.32	1628	1.17	2175	6.6
1995	181	1.30	1628	1.16	2187	6.6

3.6.3 (Continued)

the two counties are quite similar. Applying the generally accepted rule-of-thumb that additional growth of less than 7-10%/year usually can be accommodated without precipitating adverse impacts, neither Yellowstone nor Big Horn counties is likely to be significantly affected by the presence of the synfuels facility. If all the in-migrants were to settle within the limits of Billings and Hardin, the impact threshold would only be exceeded in Hardin and only during the period of greatest construction activity.

The same is not true for Sheridan County. With the city of Sheridan being the only major population center within reasonable commuting distance of Site 23, it is expected to host almost the entire in-migrating project-related population. The effect as presented in Table 3.6.3-1, is that the population impact threshold is exceeded in Sheridan County by a factor of twc during the major construction period.

3.6.4 Infrastructure And Fiscal Effects

Given the number of newcomers expected in the communities and areas surrounding Sites 1 and 23, estimates were prepared of their demands for public and private sector facilities and services such as housing, health services, water and sewer facilities, police and fire service, educational facilities and services, and others. The additional costs of providing the public services and facilities projected to be required to accommodate this increased growth were estimated using cost factors prepared for the U.S Department of Energy (see Volume IV, Part C, Appendix C-3, Summary of Community and Fiscal Impact Factors). In conducting the analyses of public costs, the capital costs were assumed to be met through the issuance of either revenue or general obligation bonds. The annual costs of servicing this debt were added to the estimated annual operating costs of increasing service levels.

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3.6.4 (Continued)

In contrast, the increased revenues from property and - in the case of Sheridan and Sheridan County - sales taxes associated with the increased populations and economic activities in these areas were also estimated. The net public fiscal effects were estimated by subtracing the expected costs of accommodating the needs of the new populations from the incremental public revenues directly and indirectly contributed by the newcomers. The results for Billings and Hardin (Site 1) and Sheridan (Site 23) are presented in Table 3.6.4-1.

These figures are only rough estimates of the actual net fiscal balances likely to be experienced by the host communities. They do not reflect existing excess capacities in the people-serving infrastructures of these communities nor do they reflect all possible sets of expenditure requirements or revenue sources. However, even though they may not measure precisely the actual dollar effects of growth, they do illustrate, for similar revenue and expenditure items, the relative fiscal effects of growth in each community. Just as importantly, they indicate the relative degree to which each community is likely to be adversely impacted by the synfuels facility.

When rapid growth is imposed on a community, the demands for private and public services are correspondingly increased. If the demands for private-sector goods and services are not met, the consequence is generally localized inflation with the distribution of scarce goods going to those with the greatest ability to pay. The people likely to suffer most under these conditions are those on fixed incomes and/or those who do not directly benefit from the growth-producing process. When the demands for publicly provided goods and services are not met (due to a shortage of public capital and revenues), the consequence is that there is less for everyone. As observed in a similar study (see Section 2.3, Volume IV, Part C), of boom towns, such shortages lead to frustrations on the part of local and

TABLE 3.6.4-1

NET PUBLIC FISCAL IMPACTS

Location	Revenues	Expenses	Service	Balance[a]
Site 1				
Billings	$1,952,287	$2,104,397	$2,114,538	-$2,266,648
Hardin	698,273	233,966	235,093	+229,214
Site 23				
Sheridan	2,010,530	2,826,976	2,840,600	-3,657,046

[a]These figures are for the operations period when the project-related populations have stabilized

in-migrating populations with the effect that the productive members of both groups leave. This results in high turnover and lower productivity in both the basic and secondary sectors. This reduced productivity leads to further declines in the provision of public goods and higher costs in constructing and operating the growth-producing facility. With an annual wage bill of $70-100 million in both the third and fourth years of plant construction (see Table 3.6.3-1), a reduction in worker productivity of 30 percent due to impact precipitated turnover carries a price tag of $21-30 million.

The likelihood that such conditions might arise at Site 23 is significantly greater than at Site 1. As illustrated in Table 3.6.4-1, nonconstruction growth is expected to "pay its own way" in Hardin. With Billings hosting 90 percent of the in-migrating population, a deficit of $2.3 million is expected in each year of plant operation. This represents just over 5 percent of the total 1980 revenues collected by Billings. In Sheridan, the net annual contributions to the community's deficit is expected to be just over $3.6 million during the operating period. This represents more than 30 percent of the city's 1982 budget of $11.5 million. Thus, when viewed as a proxy of impact severity, the figures in Table 3.6.4-1 suggest that, unless the synfuels plant underwrites a sizable proportion of the infrastructure requirements, Sheridan may experience significant shortages in the provision of public facilities and services. The effects of these shortages may increase substantially the direct cost of construction and operating the facility at Site 23.

3.7 SPECIAL STUDIES

3.7.1 RESOURCE AND SITE ANALYSIS

Special studies were necessary to analyze resources and sites suitable for the Crow Tribe of Indians proposed synfuels plant. Eleven candidate sites for the synfuels plant were evaluated based on environmental conditions, coal supply, transportation considerations, solid waste disposal, water supply, and the site conditions. The candidate sites were screened down to four sites for detailed analysis (Sites 1, 1A, 20, and 23). Site No. 1 has the lowest overall costs, however Site No. 23 is favored because it is a minemouth location. The analyses that led to these decisions are described in the sections that follow. Basic assumptions for performing the financial analysis in each study are shown in Table 3.7.1-1. Cost are based on January 1, 1982 dollars.

TABLE 3.7.1-1

BASIC ECONOMIC ASSUMPTIONS

Debt/Equity Ratio	75/25
Debt Term	20 years
Debt Interest	15%
Interest During Construction	15%
Return of Equity	15% in constant dollar terms
Facility Life	25 years
Book Depreciation	25 years, straight line
Tax Depreciation	5 years - ACRS: 20%, 32%, 24%, 16%, 8%
Federal Income Tax	46%
State Income Tax	6.75%
Ad Valorem Tax and Insurance	2.5% of fixed capital
Tax Credit	10% of total investment as incurred
Working Capital	1/6 of annual operating costs
Salvage Value	Zero net value
Land	Negligible
In-Service Date	July 1, 1989

3.7.1.1 Coal Supply Study

The purpose of this Coal Supply Study is to evaluate the potential coal sources for the Crow Tribe of Indians Synfuels Project. Coal cost is the single largest item of the overall plant operating costs, exclusive of capital charges, making it a significant factor in determining the economic viability of the synfuels project. Two coal sources are evaluated in this study. The two coal sources are the existing Absaloka Mine located in the easterly portion of the ceded area bordering on the northerly line of the Crow Reservation operated by Westmoreland Resources, Inc. and the proposed mine in the southeast corner of the Crow Reservation being developed by Shell Oil Company. The technical considerations and minemouth costs are presented for each coal.

Technical Considerations

Coal samples were obtained from both sources and shipped to Lurgi in Germany for laboratory analysis. Tests indicated that both coals are very similar in quality and that both are good Lurgi gasifier feeds. The Westmoreland coal has a higher sulfur content and the ash has a higher alkali content than the Shell coal, but both of these values are sufficiently low so there is no significant process penalty. Coal size is specified to be 2 x 0 inch at the mine with a maximum of 40 percent fines defined as the fraction of coal screening 1/4 x 0 inch. Westmoreland provided coal size distribution data indicating that they can meet these criteria. Shell did not have data indicating the distribution of coal sizes within the 2 x 0 inch range, but stated that they can meet this constraint.

Tables 3.7.1-2 and 3.7.1-3 summarize the Lurgi laboratory analyses of the two coals.

TABLE 3.7.1-2

WESTMORELAND RESOURCES, INC.
(Absaloka Mine Coal)

	Values-wt.%
Proximate Analysis, % (as received)	
Moisture	26.0
Ash	7.4
Volatile Matter	26.5
Fixed Carbon	40.1
	100.0
Thermal Energy, Btu/lb	8612
Ultimate Analysis, % (DAF)	
Carbon, C	75.98
Hydrogen, H_2	4.59
Sulfur, S	1.23
Nitrogen, N_2	1.09
Chlorine, Cl	0.03
Oxygen, O_2	17.08
	100.00

TABLE 3.7.1-3

SHELL Oil Company
(Youngs Creek Coal)

	Values - wt.%
Proximate Analysis, % (as received)	
Moisture	26.3
Ash	4.1
Volatile Matter	32.5
Fixed Carbon	37.1
	100.0
Thermal Energy, Btu/lb	9090
Ultimate Analysis, % (DAF)	
Carbon, C	75.51
Hydrogen, H_2	5.19
Sulfur, S	0.55
Nitrogen, N_2	1.26
Chlorine, Cl	0.03
Oxygen, O_2	17.46
	100.00

3.7.1.1 (Continued)

Economic Considerations

Estimates of prices for coal sized 2 x 0 inch FOB the mine were obtained from both Westmoreland Resources, Inc. and Shell Oil Company. The prices are based on providing the coal feed required for a synfuels plant as proposed in this feasibility study.

Table 3.7.1-4 summarizes information pertinent to the coal supply.

The synfuels project has two excellent feed coal sources that can be considered. The coals from both sources are similar in quality and the total tonnage required owing to the different gasification characteristics of each coal is almost identical. Westmoreland is presently operating a mine producing coal in quantities comparable to what the synfuels plant requires. They have the equipment available and an approved mining plan to proceed with supplying coal to the synfuel plant within a year after signing a contract.

Shell is well along with developing their mining project by virtue of having submitted their environmental impact report. Shell plans to have their mine in full operation in 1986 which will easily meet the requirements of the startup schedule proposed for the Crow Synfuels Project. The Shell coal costs are considerably higher than the Westmoreland coal costs, but Shell has the advantage that the synfuels plant can be located near the minemouth. The final ranking of the coal supply can only be done after evaluating coal transportation, water supply, access roads, site preparation, and differences in process plant requirements.

3.7.1.2 Coal Transportation Study

Siting of a synfuels facility is greatly influenced by the coal source. It is desirable to locate the facility near the mine (minemouth plant) to minimize transportation costs when possible; however, environmental and

TABLE 3.7.1-4

COAL ECONOMICS

	Westmoreland	Shell
Amount of Coal Required, millions of tons annually		
Plant Size, 125 MMSCF/D	5.976	5.843
Plant Size, 250 MMSCF/D	11.95	11.69
Cost of Coal (loaded by unit train), dollars per ton (includes royalty)	10.70	15.50 (15.10)*
Coal Size, inches	2 x 0 (40% fines max)	2 x 0 (40% fines max)
Mine Status	Operating	Operational, 1986
Coal Reserves-30 years, million tons	838	750

* Delivered by conveyer to Site 23

3.7.1.2 (Continued)

socioeconomic considerations may require a nonminemouth installation. This study investigates the technical and economic aspects of transporting coal from two mine locations to three candidate gasification plant sites, designated Sites 1, 1A, and 20. A fourth candidate site, Site 23, is minemouth and does not require rail transportation.

The design basis for the coal transportation system is the transportation of approximately 18,000 tons per day, 332 days per year which is approximately 6.0 million tons per year. Thirty days of dead coal storage and 5 days of live coal storage are provided. The system includes coal loading facilities owned by the coal company; unit trains, existing rail, fueling facilities, and maintenance facilities owned by the railroad; and new rail and coal unloading facilities owned as part of the synfuels project. An option to own the rail cars as part of the project is also evaluated. Conveyors were eliminated from further consideration because of high initial capital costs and lack of proven experience for this lenght of conveyor.

Another option evaluated in this study included minimizing initial capital investment by using maximum existing rail versus using a more direct route requiring new rail and fewer cars to lower operating costs. For each option, both Project and Carrier owned cars are analyzed.

A total of twelve cases are evaluated in this study to determine the coal transportation costs. The lowest transportation costs was for shipping Shell coal to Site 20. Westmoreland coal transportation cost were lowest for shipping to Site 1. The cases and the sites they represent are summarized in Table 3.7.1-5. Capital and operating costs and a calculated cost per ton based on overall project economics are presented for each of the cases. The source of the cost information is Burlington Northern Railroad who have rail facilities in the area.

3.7.1.2 (Continued)

Case 1 serves Site 1 from the Westmoreland mine (136 miles)
Case 2 serves Site 1 from the Westmoreland mine (60 miles)
Case 3 serves Site 1A from the Westmoreland mine (143 miles)
Case 4 serves Site 20 from the Westmoreland mine (194 miles)
Case 5 serves Site 20 from the Westmoreland mine (93 miles)
Case 6 serves Site 20 from the Shell mine (62 miles)

Alternate Cases reflect the options discussed above.

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TABLE 3.7.1-5

TRANSPORTATION SYSTEM CAPITAL AND OPERATING COSTS

Site	Case	Capital ($000)	Annual Operating ($000)	Transportation Cost ($/ton)
1	1	13,059	24,725	4.49
	1 Alt	24,059	22,007	4.26
	2	78,354	15,385	4.28
	2 Alt	84,404	14,171	4.21
1A	3	22,491	25,634	4.85
	3 Alt	34,017	23,059	4.65
20	4	6,530	33,129	5.79
	4 Alt	19,180	29,758	5.48
	5	61,668	19.797	4.68
	5 Alt	68,968	17,796	4.50
	6	6,530	18,668	3.40
	6 Alt	14,780	16,622	3.22

Note: Site 23 is excluded from this study. This site does not have a coal transportation cost since the plant is minemouth and Shell's coal cost is priced at the plant boundary.

3.7.1.2 (Continued)

The coal transportation costs developed for the twelve cases indicate that the captive rail system cases show a lower evaluated cost. They also indicate that using Project owned coal cars results in lower transportation cost. In assessing these results the following should be noted:

> The captive rail cases add an additional $65 million to the project capital cost. This is a significant increase in an already capital intensive project.
>
> Using Project owned coal cars will create some special maintenance requirements. Burlington Northern normally does not maintain equipment they do not own. Therefore, it would necessitate finding a location where the cars could be serviced. Extra charges are incurred on a cents per mile basis when cars are routed to maintenance areas not along the existing system.

For the overall project analysis, the Base Case assumed minimum new rail and coal cars owned by Burlington Northern. Sensitivity analyses addressed the other options.

Of the three sites evaluated, Westmoreland coal can be shipped to Site 1 for the lowest cost. Shell coal can be shipped to Site 20 at less expense than can Westmoreland coal. Shipping Shell coal to Site 20 gives the lowest overall coal transportation cost.

3.7.1.3 Solid Waste Disposal Study

The synfuels plant produces several solid wastes that require disposal. The solid waste disposal site receives ash from the Lurgi coal gasification units, ash from the boilers, and sludge from the Flue Gas Desulfurization Unit (FGD). Other solid wastes from the plant are water treatment

3.7.1.3 (Continued)

sludges, spent catalysts, and general plant refuse. Most of the spent metallic catalysts are returned to the catalyst manufacturer, while the spent nonmetallic catalysts and general refuse are disposed at a local public waste disposal site.

This solid waste disposal plant is specific to plant Site 1 assuming coal from the Westmoreland mine as the feed. The disposal site is located in a natural valley approximately 1/2 mile northwest of the synfuels plant. Solid waste returned to the Westmoreland mine for disposal was not evaluated in detail because of the distance between the plant and the mine; also the logistics of transporting water containing wastes in a cold environment would be difficult. If plant Site 23 is selected, the ash will be disposed at the Shell mine. Solid waste disposal at the Shell mine is not included in this study.

The plant will produce approximately 13.5 million cubic yards of compacted waste. The volume of solid waste comes from gasifying 18,000 tons per day of coal to produce 125 MMSCF/CD of SNG. This disposal site is adequate to contain the wastes for 25 years. It is not sufficient to accommodate the solid wastes from a plant producing 250 MMSCF/CD. If the initial synfuels plant is expanded, an additional disposal site will be required.

Table 3.7.1-6 summarizes data from the study.

TABLE 3.7.1-6

SOLID WASTE DISPOSAL DATA

Synfuels Plant Site	Site 1	Site 23
Coal	Westmoreland	Shell
Distance to mine	136 miles by rail	minemouth
Disposal plant distance	1/2 mile from synfuels plant	minemouth
Estimated Capital Cost,		
Waste facilities, $million	4.2	--
Operating Cost, annual, $million	2.2	--
Cost per ton (dry basis), dollars	5.20	5.50*
Cost per ton (wet basis), dollars	3.84	--

*Estimated by Shell Oil Company and assumes using encapsulating materials indigenous to area.

3.7.1.3 (Continued)

The disposal site and facilities approximately 1/2 mile from the synfuels plant consist of the following:

Ash conveying system, covered, 24-inch wide belt conveyor
Office building, steel frame with insulated walls and roof
Security building, steel frame with insulated walls and roof
Equipment maintenance and storage building, containing overhead bridge crane
Mobile equipment
Approximately 230 acre site in natural valley flanked by 2 ridges
Perimeter fencing
Access (5,000 feet) and perimeter (12,000 feet) roads

Major steps in the waste disposal site development plan are:

(1) Excavation and stockpiling of topsoil and overburden.
(2) Construction of berm and bottom clay liner.
(3) Disposal and compaction of waste solids.
(4) Placement of clay liner over solid wastes.
(5) Placement of overburden and topsoil over top clay liner.
(6) Revegetation with grasses and shrubs that blend with existing terrain.

A water drainage channel leading to a downstream pond is also included in the site development plan.

When necessary, water sprays, daily covers, or chemical binders can be used to minimize the generation of dust.

3.7.1.3 (Continued)

While none of the solid wastes are believed to be hazardous, precautions are taken to prevent contamination of existing aquifers. The clay liners are compacted to a permeability of 10^{-7} cm/sec, or less. The top and bottom clay liners and the overburden layers are each five feet thick.

The topsoil layer is one foot thick. Four monitoring wells are installed, two hydraulically upgradient and two downgradient of the potential leachate path. Typical indicator parameters will be checked on a monthly or quarterly basis.

During the initial site development, an area within the disposal area is excavated and lined with clay. This area is sufficient in size to accept the volume of solid waste produced for the first two years of operation of the synfuels plant.

3.7.1.4 Raw Water Supply Study

Suitable water in sufficient quantities is essential for a synfuels plant. Consideration must be given to the impact on environmental regulations, quality of the water, its movement to the plant site, and its storage. Water treatment adds to the overall operating costs. Specific process steps require different quantities and qualities of water.

This study concerns the movement of water to the plant site.

The purpose of the study is to select a source of raw water and to develop a plan for transporting the water from the source to each potential plant site. The sites under investigation are 1, 1A, 20 and 23. Water sources are Alternate 1: Big Horn River, and Alternate 2: Yellowtail Reservoir.

3.7.1.4 (Continued)

Design flow rates are 7,000 gpm for the initial synfuels plant (125 MMSCF/CD) and 14,000 gpm for the expanded plant (250 MMSCF/CD). Transport of the water to the site is through underground piping systems.

Using a friction loss guideline for cross-country water lines of 3 to 5 feet per 1,000 feet, a 30 inch diameter pipe is recommended for the 14,000 gpm flow. The piping will conform to American Water Works Association Standards. The AWWA Code requires a coal tar enamel internal lining that produces a lower roughness factor than ordinary steel pipe.

The scope of work includes the following for each of the the four plant sites and two alternate water supply points:

- Routing of the pipeline for the 2 water sources to each of the 4 plant sites based on topographic maps of the area.
- Sizing of the pipeline including pipe schedule, metallurgy and design conditions.
- Determining the number and location of the pump stations, and the specifying and selection of the pumps.
- Developing capital and operating costs for each of the systems.

The pipeline routing used to evaluate pipeline costs for each case was developed from topographic maps to best fit the land contours between the sources and plant sites. American Water Works Association (AWWA) standards for underground water piping were followed in selecting the pipe to be used. The costs per foot of pipe were obtained and the maximum allowable working pressures were calculated using a Fluor piping standard that conforms to AWWA for various pipe schedules of both 24 inch and 30 inch nominal sized pipe. The calculation makes allowances for a 1/16 inch corrosion factor and an 85 percent joint factor in the pipe fabrication.

3.7.1.4 (Continued)

The pumping requirements were split into three 50 percent pumps. Thus, each pump station has a spare pump. Each pump station has the necessary supporting facilities. Commercially proven standard water pumps were selected.

In the pump station optimization study, an investigation was made comparing pump station capital costs with piping capital costs for the 14,000 gpm flow rate. Site 23 was chosen for this study with Alternate 1 as the water source. Five cases were compared starting with a single pump station and concluding with a five pump station case. For each case, pipe size and schedule were selected to meet the maximum operating pressure required.

The pipeline maximum design pressure is set at 500 psi for all cases. This conclusion was reached in the pump optimization substudy. The hydraulic analysis of each plant site shows that single pump stations are required for Plant Site 1 and Site 1A, three pump stations are required for Site 20 and four pump stations are required for Site 23. Three pumps sized to deliver 50 percent of the required flow are provided for each pump station. The water source for Alternate 1 is from the Big Horn River at the abandoned bridge in Sec. 20, T2S, R33E at the beginning of two Leggins Canal. The water source for Alternate 2 is at the Yellowtail Dam pumping from the lake side of the dam. Both capital and operating costs favor Site 1, Alternate 1 (river). The costs associated with the other three sites favor Alternate 2 (dam). This evaluated cost for supplying water to the various sites is summarized in Table 3.7.1-7.

TABLE 3.7.1-7

WATER PIPELINE COSTS

Site	Source of Water	Fixed Capital ($000)	Annual Power Consumption (10^3 kWh)	Annual Operating Costs ($000)
1	River (Initial plant)	15,207	8,143	391
1	River	20,560	18,279	391
1	Dam	30,333	10,502	391
1A	River	30,248	26,183	391
1A	Dam	32,695	15,012	391
20	River	42,953	52,127	460
20	Dam	39,500	36,621	460
23	River	73,180	83,776	807
23	Dam	70,290	66,071	807

3.7.1.5 Site Analysis Study

The selection of a site for a synfuels plant involves many considerations including, but not limited to, usable area, topography and drainage, environmental impact, access (road, railroad, etc.), raw water supply, present land use, proximity to population centers, and governmental regulations.

This substudy evaluates 11 candidate sites on the Crow Reservation in Montana. The analysis of the candidate sites is based on the following criteria:

(1) The minimum usable area required for the plant site is 750 acres.

(2) Topography and drainage of the site must be evaluated.

(3) The plant site is to be on the Crow Reservation with emphasis on use of tribally owned lands.

(4) The coal is mined from resources located on the Crow Reservation. With two different sources of coal, the best plant site for each is to be selected.

(5) The water is supplied from the Big Horn River within the Crow Reservation.

(6) The site and the immediate vicinity shall have minimum impact on tribal lands of cultural significance.

3.7.1.5 (Continued)

(7) The plant emissions should meet the environmental standards of record with particular concern for the nearby Northern Cheyenne Indian Reservation Class 1 air quality designation. The boiler stack shall be of sufficient height to disperse flue gas constituents so as to meet air quality standards.

Many of these criteria are applicable to the 11 candidate plant sites so that emphasis is to the environmental, site preparation, coal and water supply, and the transportation considerations.

Information came from various sources and included a site reconnaissance trip, using either 4-wheel drive vehicles or helicopters, to each of the candidate plant sites. After a preliminary screening, 7 of the 11 sites (Sites 6, 7, 9, 21, 24, and 25) were eliminated primarily for environmental reasons: emissions affecting the Class 1 air quality requirements for the adjacent Northern Cheyenne Indian Reservation.

The remaining 4 sites (Sites 1, 1A, 20, and 23) were evaluated in depth. The coal will be supplied from either the Westmoreland mine or the Shell mine; raw water will be brought from the Bighorn River or from the Yellowtail Reservoir.

The more important features for each site are compared in Tables 3.7.1-8 through 3.7.1-11. Road access to each site requires new roads and upgrading existing roads from main highways. Using maximum length of existing rail and carrier owned rail cars reduces capital costs but increases operating costs. A substudy optimizes pipe and pump size and quantities for required water supply. Site preparation and civil work includes necessary excavation and fill.

TABLE 3.7.1-8

SITE COMPARISON - ROAD ACCESS

SITE NO.	SITE LOCATION T,R; SECT.	DISTANCE FROM BILLINGS, miles	DISTANCE FROM HARDIN, miles	ACCESS ROAD, miles ALT 1 NEW	ALT 1 UPGRADED	ALT 2 NEW	ALT 2 UPGRADED
1	T2S, R31E; Sects. 16, 17,20,21	45	15	10	0	8	2
1A	T2S, R29E; Sects.13, 14,22,24,26 27	25	28	7 1/2	11	-	-
20	T8S, R35E; Sects. 19, 20,29,30	95	50	1/2	3	-	-
23	T9S, R38E; Sect. 11	115	70	29	0	-	-

TABLE 3.7.1-9

SITE COMPARISON - RAIL ACCESS

SITE NO.	RAILROAD (MINE TO SITE), miles ALT 1 NEW	ALT 1 EXISTING	ALT 2 NEW	ALT 2 EXISTING	ALT 3 NEW	ALT 3 EXISTING	MINE
1	47[a]	12 1/2[a]	9[b]	127[b]	54	0	West-moreland
1A	53 1/2	12 1/2	15 1/2[c]	127[c]	62 1/2	0	West-moreland
20	4 1/2[d]	190[d]	42 1/2[e]	50 1/2[e]	-	-	West-moreland
	4 1/2[f]	57[f]	22 (Conveyor)	0	-	-	Shell
23	2 (Conveyor)	0	-	-	-	-	Shell

Notes: a. Case 1 in the Coal Transportation Study
b. Case 2 in the Coal Transportation Study
c. Case 3 in the Coal Transportation Study
d. Case 4 in the Coal Transportation Study
e. Case 5 in the Coal Transportation Study
f. Case 6 in the Coal Transportation Study

TABLE 3.7.1-10

SITE COMPARISON - WATER SUPPLY PIPELINE

	PIPELINE				
	ALT 1		ALT 2		
SITE NO.	LENGTH, miles	STATIC LIFT, feet	LENGTH, miles	STATIC LIFT, feet	AVG. SITE ELEV., feet
1	11 1/2[a]	390[a]	26[c]	85[c]	3300
1A	21 1/2[a]	500[a]	d	d	3450
20	48[b]	1050[b]	d	d	4000
23	64[b]	1870[b]	61[c]	1225[c]	4360

[a] Intake at Bighorn River near abandoned bridge (Sect. 20, T2S, R33E)

[b] Intake at Bighorn River near junction of Crow Road Coulee and Highway 313 (Sect. 32, T2S, R33E)

[c] Intake at Bighorn Reservoir near Yellowtail Dam

[d] Not evaluated

TABLE 3.7.1-11

SITE COMPARISON - EARTHWORK

SITE NO.	LAND USE	EARTHWORK CUT AND FILL (EACH), cubic yards
1	Dry Land Farming	5×10^6
1A	Dry Land Farming	11×10^6
20	Grazing	20×10^6
23	Grazing	7.5×10^6

3.7.1.5 (Continued)

Capital and Operating Costs

The summaries of the capital and operating costs associated with the above items are listed below for each of the four sites.

Site	Coal Source	Total Capital Cost ($ Million)	Annual Operating Costs ($ Million)
1	Westmoreland	54.5	89.7
1A	Westmoreland	92.2	90.8
20	Westmoreland	125.3	99.1
20	Shell	125.3	115.7
23	Shell	104.4	96.0

These capital and annual operating costs were input into a financial model to determine the ranking of the various sites. The resulting costs are presented as a cost-of-service in dollars per thousand cubic feet ($/MCF) of SNG produced. This represents only the cost-of-service associated with the items previously discussed and does not represent the total cost of producing the final SNG product. It is used for ranking purposes only.

Site	Coal Source	($/MCF) Cost-of-Service
1	Westmoreland	2.17
1A	Westmoreland	2.31
20	Westmoreland	2.59
20	Shell	2.96
23	Shell	2.46

3.7.1.5 (Continued)

Results of the study indicate that Plant Site 1 has the lowest overall cost-of-service based on the parameters considered.

The two sites that indicate the lowest cost for each coal supply are Site 1 using the Westmoreland coal and Site 23 using the Shell coal. Site 1 has the lowest cost in every area except coal transportation. Having to transport the coal 136 miles is a significant disadvantage; however, other positive aspects of the site result in it having the lowest cost-of-service. Site 1A is more costly than Site 1 because it requires additional costs in every category. Site 20 is the most costly for the Westmoreland coal supply of the three sites (1, 1A, 20) considered. Coal transportation costs and additional site preparation costs comprise the major cost differences.

Site 23 is the most economic of the two sites (20, 23) evaluated for the Shell coal supply. Site 23's main advantage is that it is located adjacent to the mine (minemouth plant). However, this advantage is offset by the higher costs for coal, water supply system, access road, and site preparation.

For Site 20 the water supply system is less costly than for Site 23, but coal transportation costs more than offset this difference.

3.7.1.5 (Continued)

Comparing Site 1 and Site 23 shows that Site 1 has the lower cost-of-service. The difference is primarily because of the more expensive water supply system for Site 23. There are advantages and disadvantages for each of the two sites. These are tabulated as follows:

SITE 1

Advantages

Site is located entirely within Trust land, tribally or individually Indian-owned land.

Site is near population centers so as to provide adequate labor sources.

Site is reasonably level.

Terrain adjacent to the site provides a natural depository for the solid waste.

Coal source is from an existing operating mine readily able to supply the quantity of coal required.

Future expansion of the plant is possible due to the relatively level surrounding areas.

Site is near a water supply of sufficient quantity.

Disadvantages

Site requires a long rail transportation system for delivering coal.

3.7.1.5 (Continued)

Site is affected by the Class I air quality area of the Northern Cheyenne Indian Reservation which increases sulfur recovery costs to meet environmental standards.

SITE 23

Advantages

Site is located adjacent to the proposed mine providing for a minemouth synfuels plant.

Site is remotely located making it more aesthetically acceptable.

Site is not affected by the Class I air quality of the Northern Cheyenne Indian Reservation.

Construction at Site 23 will improve access to the southeast area of the Reservation for the Crow Tribe.

There will be less socioeconomic impact to the Hardin and Billings areas during plant construction because part of the work force can come from the Sheridan, Wyoming area.

Disadvantages

The remote location increases length of the water line, access roads, power lines, and gas pipelines impacting the economics of the synfuels facility.

The terrain is rougher, limiting the area available for the synfuels plant and increasing site preparation costs.

3.7.1.5 (Continued)

Site 1 is the most suitable of the sites considered for using Westmoreland coal. However, if the Class I air quality area was reclassified, or if the plant size was limited to 125 MMSCF/CD without export power, selecting a site near the Westmoreland mine would improve the economics associated with using Westmoreland coal. Site 23 is the best site identified for using Shell coal. The rugged terrain and the constraint of the reservation boundary eliminate any other possibilities for siting a synfuels plant close to the Shell mine.

An overall evaluation of Site 1 and Site 23 including the process considerations are presented in detail in Volumes II and III of this study.

3.7.2 Product and Byproduct Market and Transportation Analyses

The purpose of the SNG Market, Byproduct and Transportation analyses is to identify the best disposition for both the SNG and major byproducts produced by the proposed synfuels plant. The study also involves a transportation analysis for moving the SNG to market by various pipeline systems including an assessment of the related environmental impacts. The planning horizon for this study extends through the 1990's, with initial plant operation to begin in 1989. All prices are in first quarter 1982 dollars.

For the purpose of this study, the market analysis for the SNG is the southern California market. Consideration is given to existing regional pipeline facilities as well as for new pipeline facilities to transport the SNG to the southern California market. Existing regional pipelines considered are those of Montana Power Company and Montana-Dakota Utilities Company. Five new pipeline facility options are identified and analyzed in the study.

The study also analyzes the market for the following major byproducts:

(1) Ammonia
(2) Naphtha
(3) Sulfur
(4) Methanol
(5) Phenol
(6) Tars and tar oils
(7) Electric power (surplus)

The byproduct analysis includes the characterization of the potential market for the major byproducts. The study also identifies a regional market for electrical power.

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3.7.2.1 SNG Market Analysis

The source document used for the SNG Market Analysis was the 1981 California Gas Report. This document indicates that the southern California natural gas market is expected to be under relatively heavy curtailment in the late 1980's and 1990's. This finding assumes that the utility's supplemental natural gas supply program (LNG, Alaskan North Slope, et al) is successful. Effects of conservation programs, mandated energy efficiency standards and customer sensitivities to changing gas prices have also been included to lower the potential demand. Also assumed is the decontrol of natural gas under the Natural Gas Policy Act of 1978 which presumably will serve as an incentive for widespread natural gas exploration and production.

The southern California market is expected to have a potential of 160 BCF to 225 BCF unsatisfied annual demand during the 1988-1995 period, averaging 528 MMSCF/CD. If the total amount of SNG produced in the initial plant (125 MMSCF/CD) is dedicated to this market, it could still provide only 22 percent of the unsatisfied demand, provided of course that the SNG is competitively priced. Doubling of the volumes of SNG produced with construction of a second plant module will increase the market share to an expected 57 percent. Forty-three percent of the demand still would remain unsatisfied.

Under a low gas demand case, called a "Hot Year" by the utilities, the demand for natural gas, hence SNG, decreases to minimum levels. Assuming the optimistic gas supply assumption outlined above, initial plant volumes will still average only 30 percent of the unsatisfied market in a "Hot Year". Doubling of the volumes with the addition of a second plant module, however, is projected to satisfy 88 percent of the potential demand. A basic assumption of the market analysis was that the SNG could be competitively priced against other natural gas sources and alternate fuels in the southern California market.

3.7.2.2 SNG Transportation Analysis

A 264 mile, 24 inch pipeline from the synfuels plant to the Northern Border Pipeline appears to be the least-cost SNG transportation option from an initial investment perspective. The route evaluated utilizes existing regional utility corridors. The SNG could be delivered by exchange with energy equivalent volumes of natural gas through existing systems serving southern California.

Direct capital costs for this system is placed at approximately $158 million. No compression will be required for initial plant peak volumes of 144 MMSCF/CD. Volumes from a second plant module will require a modest 3000 HP compressor station with an estimated $6 million price tag.

An alternative offer for subsequent financial evaluation is that of using the proposed Rocky Mountain system. This alternative, while high in initial capital investment ($282 million), offers fewer unknowns in the use of the interstate pipeline system that is expected to be in place in the late 1980's. It also requires an estimated one seventh of the fuel for operation as the Northern Border possibility.

3.7.2.3 Byproduct Analysis

For purposes of evaluating the feasibility of the synfuels plant proposal, major byproducts have been analyzed to determine if additional revenue could be realized from their sale. Table 3.7.3-1 summarizes these findings. Included as potential byproducts are chemical- and fuel-grade methanol. Minor "throw-a-way" byproducts are left for future studies.

A market for the ammonia currently exists and should continue since the prevailing feedstock for the current ammonia industry is high priced natural gas. As the price for natural gas escalates upward in real terms,

TABLE 3.7.3-1

BYPRODUCT SALES SUMMARY

PRODUCT	STREAM-DAY QUANTITY[1]	ANNUAL QUANTITY[2]	UNIT PRICE	ANNUAL GROSS INCOME	ESCALATION INDEX
Ammonia	76.8 ST	25,509 ST	$235/ST	$6.0 MM	Natural Gas
Naphtha	196.2 ST	65,168 ST	$268/ST	17.5 MM	Rocky Mt. distillate
Sulfur	87.2 ST	28,963 ST	$ 60/mT	1.7 MM	PPI (WPI)
Methanol-Fuel	73 MMBtu	24.2 x 10^6 MMBtu	$2.00/MMBtu	48.4 MM	Western distillate
Methanol-Chemical	3750 ST	1.25 MMST	$175/ST	219 MM	Natural Gas
Phenols	64 ST	21,258 ST	none	none	N/A
Tar/Tar Oils	350 ST	116 ST	none	none	N/A
Electric Power	278 MW	2.22 x 10^6 MWhr	3.97¢/kWh	$88.0 MM	

Notes

1 - Representative quantities. Subject to verification in future studies. Westmoreland coal.

2 - Assumes 332 days per year production

3 - 1982 dollars

3.7.2.2 (Continued)

the demand for ammonia from alternative sources will increase. For purposes of the feasibility study, it is reasonable to assume a price of $235 per short ton, FOB plant, for the ammonia in the anhydrous form. Several regional brokers have expressed interest in purchasing the ammonia byproduct stream.

Three regional refiners have expressed interest in purchasing the naphtha. As shown in Table 3.7.3-1, a unit price of $268/ton is a representative naphtha value. However, the relatively high benzene content (40 percent) may cause a marketing difficulty. Use of naphtha for motorfuel on the reservation via naphtha-to-gasoline swap may be an interesting possibility. Although not practical on economics alone, the social benefits to the Crow Tribe of an assured motorfuel supply may have some appeal in the future.

The sulfur market in the Great Plains and Rocky Mountain regions of the United States is difficult to assess. Historical extrapolations are uncertain because of the projected large increase in oil and gas production in the Canadian and Overthrust horizons (sulfur is a byproduct of purification and refining). For purposes of the feasibility study, a fenceline market price for the sulfur probably should not exceed $60 per ton.

Although a strong methanol market could exist in the 1990's important questions remain if the Crow methanol can successfully compete in a free market. The preliminary assessment of the petrochemical methanol markets indicate that the petrochemical industry demand will be increasingly strong.

3.7.2.3 (Continued)

To meet this demand, imports of methanol will be required and as such undoubtedly will be expensive, supporting the relatively high chemical-grade methanol market value. Fuel-grade methanol will command a lower price since its major competitor in the stationary fuels market will be residual oils.

Surplus electric power has a ready buyer in the regional utility, Montana Power, provided, of course, that adequate terms and conditions can be negotiated. A representative 1982 price for the surplus electric power is 3.97¢/kWh on a straight wholesale sales basis.

The market forecast for other gasification plant byproducts does not look promising. For purposes of the feasibility study, the oil, tar, phenol, and other hydrocarbon byproducts are either consumed within the gasification plant for their fuel value or are converted in a partial oxidation unit to produce additional crude gas.

Issues identified in this study indicated a number of areas suitable for advanced analysis in work subsequent to the feasibility study. Six areas of particular interest are given in the marketing, transportation, and byproduct analyses presented in their entirety in Volume V.

3.7.3 Planning and Communications Analysis

An action plan was developed to communicate information concerning the feasibility study for the proposed synfuels plant. Inherent in the plan was an overall strategy to recognize the need to provide key decision makers with as much information, negative as well as positive, as was available to justify support or minimize opposition to the study. Initially the Crow people exhibited considerable hostility to the study. As a result of a communications effort by the Crow Tribal Office of Economic Planning and Resource Development, general opposition to the study has almost disappeared except in a small but vocal group. In meetings with local and state officials, local media and environmental organizations, and from the monitoring of local media, no organized opposition to the proposed synfuels plant seems to have surfaced. There is no reason from the standpoint of public opposition to prevent the project from moving ahead to Phase II, but recognizing that some opposition should be expected in obtaining necessary approvals.