DOE/RA/50313-1137
(DE82008137)

FEASIBILITY STUDY FOR A COAL-SOURCED METHANOL PROJECT

Final Report

January 29, 1981

Work Performed Under Contract No. FG01-80RA50313

W. R. Grace & Company
Dallas, Texas

TECHNICAL INFORMATION CENTER
UNITED STATES DEPARTMENT OF ENERGY

DOE/RA/50313-1137
(DE82008137)
Distribution Category UC-90c

FEASIBILITY STUDY FOR A COAL-SOURCED METHANOL PROJECT

Final Report

January 29, 1981

Contract No. FG01-80RA50313

W. R. Grace & Company
Dallas, Texas

p

TABLE OF CONTENTS

DOE/RA/50313--1137

DE82 008137

EXECUTIVE SUMMARY

In 1979, W.R. Grace & Co. began work with Energy Transition Corporation (ETCO) to assess the feasibility of constructing a coal-sourced methanol plant in the Axial Basin of northwest Colorado. Successive studies since that time have confirmed that such a project is technically, environmentally, and economically feasible.

These studies envisioned construction of a plant to produce 537 million gallons of methanol per year. However, it became clear that a plant of this size would have to capture an unrealistically large share of the early market available to it. Moreover, much of the output would initially go to the chemical feedstock market, reducing the benefits of concentrating sales in the more attractive transportation market. This market is now small but is expected to develop rapidly.

Accordingly, Grace believes that the most promising project development strategy is to begin with an initial module producing about 67 million gallons of methanol per year. During 1981, Grace conducted a study of this concept at its own expense, which established the feasibility of this approach.

Also during 1980, Grace received a grant from the Department of Energy primarily to assess the environmental impact and regulatory requirements of the project. In addition, this study updated the design basis and economics of the large plant. This report summarizes the results of the DOE-funded feasibility study.

This report concludes that the environmental impacts of both the initial and expanded plants are acceptable, and that all regulatory requirements can be met. A permitting schedule has been developed and agreed to by the responsible regulatory agencies that is acceptable to the project. These conclusions were reached with extensive agency and public participation through the Colorado Joint Review Process. Thus, it appears that the regulatory risks of this project are small and manageable.

The updated analysis of the large plant shows that an equity return of 31 percent (in current dollars over 20 years) is achievable on a total project investment of $1.8 billion. Only commercially available technology is used in the plant, and adequate design has been done to ensure technical feasibility and to serve as a reliable basis for cost estimates. The necessary coal, water, and land resources for the plant are controlled by Grace and can be made available for the project.

In summary, all the physical and technical resources for the project are fully in hand, and the environmental and regulatory risks are small. Engineering and financial analysis are sufficiently complete to conclude that the project is economically attractive. Market risks can be minimized by beginning with a small initial module, followed by plant expansions to serve a growing methanol market.

CHAPTER I   STUDY BACKGROUND AND APPROACH

During 1979 and 1980, W. R. Grace & Co. (Grace) began work with Energy Transition Corporation (ETCO) to assess the feasibility of a coal-sourced methanol plant in northwest Colorado. Grace and others have extensive coal holdings in the area, and the leasing of additional Federal coal is underway. However, transportation costs from the area are high, limiting the potential for a major expansion of local coal production to supply traditional coal markets. Grace believed that the production of methanol could open new coal markets by creating from coal a high-value product with lower transportation costs to market.

Grace and ETCO conducted a preliminary feasibility study of the concept in 1979, and a more detailed study in 1980. These Stage I and II studies indicated that construction of a large (5000 tons per day of methanol) plant appeared feasible economically and technically. However, a large plant presented two risks that required further analysis.

- Production of 5000 tons a day of methanol represented a substantial fraction of the market for methanol as a chemical feedstock. Moreover, the most attractive market for methanol - as an automotive fuel - had only begun to develop in 1980. For these reasons, it was not clear the production from a large plant could be successfully marketed in its early years.

- The potential for extensive energy development in western Colorado had created considerable concern over its associated environmental impact. This factor introduced a regulatory risk that was not fully evaluated in project Stages I or II.

As a result of these concerns, Grace elected to proceed on two fronts during 1981. First, it was decided to define the regulatory risks more clearly by examining environmental impact and regulatory feasibility issues in detail. Second, the option of starting operations with only a single gasifier producing approximately 675 tons per day of methanol was to be examined. This latter approach appeared to offer the benefits of accelerated construction, reduced environmental impact, and production volume at a level that the market could accept. Once the initial module was operating, the plant could be expanded to the full 5000 ton per day rate as the market developed.

These two studies became Stage III and Stage IV of the project, respectively. The Stage IV study was initiated by Grace with its own funds. Grace applied to the Department of Energy for assistance in conducting the Stage III study, and was awarded a $769,914 grant for this purpose in September, 1980. The objectives of the grant were to:

- Refine the technical, economic, and marketing results of Stage II;
- Collect detailed environmental baseline data, and quantify key impacts; and
- Develop a coordinated plan for regulatory action with federal, state, and local authorities.

This is the final report of the Stage III work. As such, it discusses primarily the feasibility of constructing the 5000 ton per day plant in northwest Colorado, and not the 675 ton per day module that would be the first production unit actually constructed. However, the economic and environmental feasibility of the large plant must be established to verify the feasibility of expanding the initial module examined in the Stage IV study as the methanol market develops. Although this report concentrates on Stage III work, results of the Stage IV study will be introduced in summary form where necessary to present a complete picture.

Much of the basic analysis for this Stage III study was performed by subcontractors. This report does not attempt to recount their reports in detail; the subcontractor reports themselves are furnished as attachments and stand on their own. Rather, this summary report presents Grace's own conclusions based on the material provided by the subcontractors, and integrates all the material into an overall assessment of project feasibility.

APPROACH TO STAGE III

As noted above, the Stage III study had three objectives: refine the technical, economic, and marketing results of Stage II; quantify the environmental impact of a large plant; and develop a regulatory action plan. The approach to these objectives is outlined briefly below.

Refine Stage II Results

Since the design basis and detailed economics for the 5000 ton per day plant had been established in Stage II, the purpose of Stage III was to update these factors based on new information obtained during the Stage III study. This new information was obtained from four sources:

- Early in Stage III, the design of the KBW gasifier was substantially altered to increase its efficiency. The production rate of the new gasifier rose to about 675 tons per day of methanol, as opposed to the 500 tons per day assumed for the older model used in the Stage II analysis.

- Environmental and regulatory analyses imposed new requirements on design. For example, a no discharge system was used in the design basis for Stage III, and some alterations in design were required to manage air emissions with an adequate safety margin.

- Design tradeoff studies were conducted to select the most efficient means of performing the CO shift, methanol synthesis, and sulfur oxide removal operations. Other studies were undertaken to minimize water and power consumption.

- Greater specificity in vendor quotes, site selection, transportation arrangements, and other factors improved the basis for cost estimates.

Grace also conducted additional work to specify the availability and cost of coal, water, and land for the plant, and this information was used in the updated economic evaluation.

Grace retained KBW Gasification Systems, Inc. to perform the technical and engineering work, and ETCO to perform the economic, financial, and marketing analyses. ETCO also served as overall project manager for both the Stage III and Stage IV studies.

Stage II had envisioned the use of methanol as a slurry medium for transporting dry pulverized coal to market by pipeline. Although Grace regards the production and sale of methanol as the essential first step in the project, it retained Pipeline Systems, Inc. (PSI) to perform conceptual studies to refine the technical issues and transportation costs of methanol-coal slurries. PSI evaluated both conventional methanol-coal slurries and the proprietary Methacoal technology in its work.

Quantify Environmental Impact

A major purpose of Stage III was to assess the environmental risks of plant construction. To achieve this purpose within the time and resources available, Grace concentrated on finding and evaluating the environmental impacts that could present the greatest risk, and on identifying ways of mitigating these impacts. Thus, Stage III represents a targeted environmental assessment, leaving for subsequent analysis those topics not likely to raise serious issues.

The environmental impact program was divided into two parts to permit Grace to concentrate its efforts on topics that were most important in assessing the environmental risks of the plant. Part I was a preliminary assessment of available data as a basis for evaluating four alternative plant sites selected by Grace, and for identifying the environmental issues requiring more detailed study. At the end of Part I, Grace selected the project site that appeared to cause the fewest environmental problems. Part II then involved in-depth studies of the key environmental issues at the selected site.

To conduct the necessary environmental assessments, Grace retained seven subcontractors, each specializing in a particular discipline. The subcontractors and their area of expertise were:

Subcontractor	Area of Expertise
Resource Planning Associates	Socioeconomic impact
Enviro-Test Ltd.	Air quality
WATEC, Inc.	Water quality
James Walsh Associates, Inc.	Soils analysis
Western Cultural Resources Management, Inc.	Cultural Resources
Western Resource Development Corp.	Ecology
Espey-Huston & Associates, Inc.	Solid waste, site selection

In addition, Grace retained Espey-Huston to provide overall control of the technical quality of the environmental impact analyses.

Develop Regulatory Action Plan

The final Stage III objective was to develop a plan and schedule for securing the necessary permits for the large plant. A Stage II analysis of regulatory strategy determined that the most efficient way to achieve this objective was to enter the Colorado Joint Review Process (CJRP). The CJRP is a mechanism developed by the State to coordinate the regulatory requirements of all levels of government and to secure agreement among all affected regulatory agencies on a schedule (the Project Decision Schedule) for processing permit applications. Also, the CJRP process includes frequent contact with the public to present the details of the project and to identify issues of special public concern.

Grace entered the CJRP on December 5, 1980. Four public meetings were held in Craig, Colorado, and the Project Decision Schedule was approved on January __, 1982. Resource Planning Associates assisted Grace in defining the permit requirements, and ETCO worked with Grace to develop the PDS.

p

CHAPTER II OVERALL CONCLUSIONS

The results of the Stage III study confirm that construction of a 5000 ton per day coal-sourced methanol plant in the Axial Basin of northwest Colorado is technically feasible. Furthermore, the environmental impacts appear acceptable and the regulatory risk is manageable. The economic returns are attractive, if the entire output of the plant could be sold at a price at least equal to the prevailing price of methanol projected in the chemical feedstock market.

However, Grace believes that the necessary markets cannot be established quickly enough to absorb economically the full plant output of 537,000,000 gallons of methanol per year. A preferable strategy is to construct an initial module producing about 67,000,000 gallons per year. Markets for this smaller output can be developed, and the initial module can then be expanded in response to market growth.

The major conclusions underlying this feasibility assessment and the plan for proceeding with this project are discussed below.

FEASIBILITY ASSESSMENT

The Stage III work documented in this report supports the following conclusions regarding the feasibility of the Chokecherry Project.

1. Resources. Grace controls adequate coal, water, and land for the plant. Electric power, telephone, and transportation facilities exist in the area.

2. Technology. All technology required for the plant is commercially available, including the KBW gasifier. Sufficient engineering has been completed to verify the site specific design, meet all environmental requirements, and serve as an adequate basis for estimating capital and operating costs. Future improvements in the design are possible, especially in the reduction of water consumption by approximately 60 percent.

3. Economics. Total project cash investment in current dollars is estimated to be $1879.9 million. Operating and coal costs escalated to the date of initial plant operation are $128.4 million and $161.9 million, respectively. Assuming the entire output of the plant could be sold as a chemical feedstock, a current dollar return on cash equity over 20 years of 31.3 percent would be realized.

4. Markets. The transportation market is the most attractive market for methanol, followed by the chemical feedstock market. The utility market is limited to supplying feed for combustion turbines to produce peaking power. The national methanol market is projected to grow 14 percent annually between 1980 and 1990, chiefly in transportation uses. However, a total methanol market of only about 800 million gallons could be served by the Chokecherry Project in 1985, and the project would have to capture 66 percent of this market to sell its total output.

5. Environment. A plant site has been selected to minimize environmental impacts. Analysis of these impacts at the site show that they are acceptable. In particular:

   - Air emissions need all federal and state standards.
   - The plant will discharge no wastewater.
   - Most solid wastes from the plant are nonhazardous. Acceptable disposal options exist for spent catalysts and solar evaporation pond sludges, which probably are hazardous.
   - No threatened or endangered aquatic or vegetation species will be affected by the plant.
   - Some impacts on terrestial wildlife are expected, but adequate mitigation measures are available. Threatened or endangered wildlife are present in the area, but the plant site will not affect their habitat.
   - Soils and cultural resource impacts are minor.

6. Socio-economic. The socio-economics impacts of initial plant construction are minor, and funds appear to be available from tax revenues in time to mitigate these impacts. Plant expansion will have larger impacts, but lead time is available to plan for their mitigation.

7. Permitting. All required permits have been identified, and only four are on the critical path: federal and state air permits, the federal water permit, and the county land use permit. Through the Colorado Joint Review Process, agreement has been reached with the agencies responsible for these permits on a decision schedule acceptable to the project.

IMPLEMENTATION PLAN

Because of market constraints, Grace does not intend to construct the 5000 ton per day plant as a first step, nor can it predict with certainty the schedule for expanding the initial module into the full scale plant. For these reasons, it is not realistic to develop a plan for implementing the results of the Stage III work as such.

The implementation steps that will be undertaken have been developed in the Stage IV study, conducted concurrently with the Stage III work but entirely at Grace expense. While this Stage III report does not provide detail on the plans developed in the privately-funded Stage IV work the overall conclusions of Stage IV are that the fast-track approach is feasible, that the projected economic returns will attract equity partners to the project, and that the project can proceed in line with the schedule developed in Stages III and IV.

The work conducted as part of the Stage III study will play a major role in implementing the fast-track approach, however. For example, the Stage III results confirm our conclusion that plant expansion is economically feasible as markets develop. Also, the environmental assessment performed for the large plant concludes that both the initial and the final plant will meet regulatory requirements. This result will be important in assuring both investors and regulators that the regulatory risks of plant expansion are manageable.

CHAPTER III RESOURCE AVAILABILITY

The proposed plant requires coal, land, resources, as well as adequate utility and transportation facility support. As discussed in this chapter, all these resources are available to the project.

COAL SUPPLY

The coal requirements of the 5,000 ton per day methanol plant have been calculated by KBW to be 13,008 tons per day of sub-bituminous Colorado coal, or 4,292,640 tons per year. For the 20 year life of the project a coal reserve of at least 86 million tons would be required. The Stage III Study focused on locating and evaluating reserves of this size in or close to the Axial Basin, either controlled by W.R. Grace or available for leasing in the near future.

The following deposits indicate promise of providing coal for the project.

> Little Bear Creek - A 30-50 million ton totally uncommitted reserve that could be brought into production as early as 1983 at the rate of 2 million tons per year. The coal analysis is attached as Exhibit 1.
>
> Hayden Gulch Federal Leases - A 70 million ton totally uncommitted reserve located immediately northwest of the current Hayden Gulch Mine. Grace was successful in obtaining these federal leases in May 1981.
>
> Hayden Gulch - A 10-12 million ton total reserve. Grace personnel estimate that 4-5 million tons could be made available.
>
> Colowyo - A 100 million ton total reserve, largely committed but with some additional production (1MM tons/yr) probably available. Although currently being surfaced mined, an additional 100 Million tons could be produced by underground mining methods.
>
> Chokecherry - A 200 million ton total reserve immediately south of the proposed plant, but which has not yet been leased by the Bureau of Land Management.

It appears that the Little Bear Creek reserve is the most secure initial coal supply for the 5,000 ton per day plant. The Little Bear Creek coal would be moved 7 miles by conveyor to rail loading, transported 25 miles by rail, and then either trucked or conveyed to the plant site.

The Little Bear Creek reserve of 30-50 million tons would sustain the plant for about 10 years. A 20 year life could be assured by supplementing this reserve with additional supplies from Hayden Gulch and Colowyo. Alternatively, Chokecherry coal or the underground reserves at Colowyo could also meet the total requirements for the initial 5,000 tons per day methanol plant. The mine-to-site transport costs would be significantly lower for the Chokecherry coal due to use of one conveyor rather than a combination of conveyor (or trucks) and unit train delivery from Hayden Gulch, and the possibility of deep mining at Colowyo.

Based on this analysis, Grace concludes that it controls adequate reserves to support the proposed plant, but that transportation costs could be reduced if Chokecherry coal reserves become available. Little Bear Creek is the most secure source of coal at the outset, and should therefore be used as the design basis for the plant. KBW has made this assumption, and has used the coal analysis shown in Exhibit 1 for its engineering and cost estimating.

WATER AVAILABILITY

Grace has initiated the development of the Thornburgh Reservoir as the major source of water for the methanol plant. The Thornburgh Reservoir will support the Grace mining requirements and ultimate plant water requirements as well, through retention of 10,000 acre feet of water dedicated to industrial use. The water will be brought to the plant by a 7.0 mile pipeline from the Wilson Reservoir, as shown on Exhibit 2.

LAND

Axial Basin Ranches (a joint venture of Grace and Hanna Mining) has obtained an option to purchase the Gossard Ranch, which includes the plant site. Axial Basin Ranches will make available to the project 200 acres of land for the plant site and the land needed for the construction of new roads to the site. Portions of selected county roads will be upgraded and the County's existing rights of way will be used for electric power lines, telephone lines, water lines, and methanol pipelines. These features are also shown on the area map in Exhibit 2.

UTILITIES

Electric power is available to the plant site from the White River Electric Association, Inc. An analysis of their rate schedule indicates that a rate of $.04/KWH (1981$) can be expected. Access for a power line to the plant site is provided for over Grace controlled land.

Telephone service will require 17 miles of cable to the plant site. Access will be over existing right of ways or Grace controlled land.

The small amount of propane gas required for gasifier startup and for pilot burners (26,880 gallons/year) will be delivered to the site by truck.

METHANOL LOADING AND TRANSFER FACILITY

A site for a new spurline off the existing Colowyo coal loadout facility is suitable for a methanol loading and transfer site. A 12" buried methanol pipeline will run from the plant site to County Road 17 and then parallel to County Roads 17 and 32. Approximately 1/4 mile west of the County Road 17 and 32 intersection, the pipeline will cross County Road 32 and proceed to the methanol loadout facility. These facilities are shown on Exhibit 2.

CHAPTER IV PLANT DESIGN

The design basis for the 5000 ton per day methanol plant was established in the Stage II study. The plant engineering work conducted during Stage III was aimed at refining this design basis by: (1) selecting the optimal unit processes for CO shift, SO_2 scrubbing, and methanol synthesis; and (2) conforming the design to environmental requirements identified during Stage III. This refined design was then used as the basis for updating estimates of capital and operating costs.

In addition, tradeoff studies were conducted during Stage III to determine how water use could be minimized and whether on-site generation of electric power would be economically attractive. Further studies of pipeline transportation of coal in methanol slurries were also conducted. These studies provided useful guidance for future design refinements. However, their results were not incorporated into capital and operating cost estimates, since the optimal tradeoffs depend on final negotiations on prices for water and electric power and on the detailed financial strategy for the project.

DESIGN BASIS REFINEMENT

Grace retained KBW Gasification Systems, Inc. to prepare an updated engineering feasibility study for the project. The KBW report is attached as Appendix A.

The technical feasibility of the coal-to-methanol plant was established during the Stages I and II studies. The plant uses commercially available technology and was originally based on the Koppers gasifier.

PLANT DESIGN

The updated KBW feasibility study contains more detailed process engineering than was available in the earlier work. Although the basic design is largely unchanged, the Stage III study incorporates these important refinements:

1. The more efficient KBW gasifier replaced the older Koppers design. The KBW gasifier is based on the Koppers gasification technology but has significantly improved heat transfer and steam generation characteristics. Each KBW gasifier gasifies 55 percent more coal than the Koppers design, reducing the

number of gasifiers required from 12 to 8. Total coal feed to auxiliary boilers is reduced by 22 percent. Total coal required per ton of methanol production declines by 7 percent for the KBW technology.

2. Optimized unit processes for CO shift, SO_2 removal, and methanol synthesis have been included in the Stage III design. The optimization studies are at Appendix B.

3. The design has been conformed to the environmental requirements identified in the Stage III study. This did not result in major design changes, but did involve more complete engineering of particulate removal, acid gas treatment, and wastewater treatment facilities.

Based on these changes, Grace believes the plant design is sufficiently complete to serve as a basis for reliable capital and operating cost estimates.

TRADEOFF STUDIES

KBW conducted tradeoff studies to evaluate options for water conservation and on-site electric power generation. These studies are contained in Appendix B, and their results are summarized below. It appears that water usage can be significantly reduced, and that cogeneration of electric power may be feasible. No final decision has been made on these options, however.

Water Conservation

The objective of this study was to investigate methods to reduce the water usage of the fullscale methanol plant. The basic plant would require 11,138 thousand gallons of water per day. The plant water use breakdown is as follows:

Make-up Water	1000 Gallons/Day	%
Potable Water	18	0.2
Boiler Feedwater-Make-up	846	7.6
Process Water	288	2.6
Cooling Tower Make-up	9,561	85.8

Misc. Service Water Make-up	144	1.3
Regeneration Water	281	2.5
	11,138	100.0

Water Discharge from Plant

Solid Waste Handling:		
Slag and Fly Dust from Gasifiers	23	0.2
Sludge	11	0.1
Boiler Ash	7	0.1
Cooling Tower Evaporative Losses	9,052	81.3
Cooling Tower Drift Losses	537	4.8
Brine to Solar Evaporation Pond	833	7.5
Misc. Vent Losses	22	0.2
Water Consumed in Process	653	5.8
	11,138	100.0

KBW examined five options for reducing water consumption:

1. Replacing water-cooled with air-cooled compressors, where possible.
2. Using a hybrid wet/dry cooling tower to achieve a 30 percent water saving.
3. Same as option 2, above, but achieving a 60 percent saving.
4. Replacing steam-driven with motor-driven compressors.
5. Using a compression cooling system.

The effect of these options on capital and operating costs are summarized below:

Option	Water Saving (Million gal/day)	Capital Cost ($ million)	Operating Cost ($ million/yr)
1	6.67	87.7	neg
2	3.03	11.0	neg
3	5.45	30.0	1.2
4	4.85	(97.0)	22.5
5	6.67	34.0	(5.4)

Options 1 and 5 appear to offer a water saving of about 60 percent over the base case. These options will be refined and evaluated.

On-Site Power Generation

Since power would be produced on site, and since steam drives would be replaced with electric drives in several areas, a number of tradeoffs on the production and use of power exist. KBW evaluated five cases to test the range of available options. They are:

1. Increase size of auxiliary boiler to generate all power on site for the base case.
2. Substitute motor-driven for steam-driven compressors, using purchased power.
3. A combination of options 1 and 2, above.
4. Cogenerate one half base case power requirements.
5. Use 10 percent of methanol output to produce all power on-site in a combustion turbine.

The results of these options are summarized below:

Option	Capital Cost ($ millions)	Operating Cost ($ millions/yr)
1	68	(5.6)
2	(97)	22.4
3	160	(5.6)
4	40	(5.9)
5	neg	(23.6) not including methanol cost

Option 4 (cogeneration) is the most attractive of the above options, and will be further evaluated. Option 5 savings would be offset by revenue loss on methanol.

PIPELINE TRANSPORTATION STUDY

Early in the Stage III study, Grace expected markets for methanol and coal to develop in southern California for both transportation and utility applications.

As a result, Pipeline Systems, Inc. (PSI) was retained to evaluate the cost and feasibility of transporting methanol or methanol/coal slurries by pipeline from the Axial Basin to Barstow, California. The PSI report is attached as Appendix C.

Two forms of methanol/coal slurries were investigated, a conventional slurry and the proprietary Methacoal technology developed and patented by Mr. Leonard Keller. Mr. Keller served as a consultant in the Methacoal work. As part of the slurry evaluation, PSI also outlined a program of development and testing needed to confirm the feasibility and operating parameters of the technology.

Based on the PSI work, which is summarized below, Grace believes that pipeline transportation of methanol and methanol/coal slurries is technically feasible. Economic feasibility would depend on the value of methanol and coal in the market, although costs compare favorably with rail transportation. However, market analyses conducted during Stage III indicate that the preferred market strategy for methanol is to sell the product of an initial module regionally for transportation uses. Therefore, pipelining of either coal or methanol to more remote markets is not necessary.

Transportation of Methanol Only

In this case, 5,000 tons per day of methanol derived from coal at the plant site in the Axial Basin would be pumped 686 miles to a proposed site near Barstow, California, for further distribution. The route goes west from Axial, Colorado, to near Rangely, Colorado, then it generally follows the proposed PGT Rocky Mountain pipeline route to a point south of Las Vegas, Nevada, where it follows a proposed utility corridor to Barstow, California. It avoids mountainous areas, Indian lands, national forests, and government land.

The pipeline will be a 10.75 inch outside diameter line and will require four pump stations at an average discharge pressure of 1260 PSI.

Four centrifugal pump stations will be equipped with two nine-stage centrifugal pumps installed in parallel. One pump required for full pipeline flow, and the other will be on standby. Tankage is provided at each end of the pipeline. A 40,000 barrel floating roof design is provided for at the feed end and three like tanks at the delivery terminal.

The capital cost estimate provided by PSI for this methanol pipeline are ($ 1981 millions):

Direct Costs		
Right-of-way and Lands		$ 8.9
Pipeline		
Materials	41.0	
Installation	34.3	75.3
Pump Stations		2.5
Tanks and Terminals		1.7
Other Facilities		5.0
Total Direct Costs		$93.4
Indirect Cost Allowances		
Engineering, Procurement and Construction Management		$ 9.3
Contingency		9.3
Total Indirect Costs		$18.6
Total Direct and Indirect		112.0
Owners' Costs (a)		2.0
Interest During Construction		13.4
Total Capital Costs		$127.4

(a) ETCO Estimate

The annual operating costs of the system are estimated at $1.8 million/year, including power ($0.8 million/year), labor ($0.5 million/year), supplies ($0.3 million/year), and a contingency allowance ($0.2 million/year). Allowing 16% of the capital for yearly capital charges ($20.38 million/year), a transportation tariff of $13.42/Ton or 4.5¢/gallon of methanol is estimated.

Transportation of Methacoal Slurry

During Stage II, PSI evaluated the costs and feasibility of pipelining a conventional methanol/coal slurry from the Axial Basin to Barstow, California. In Stage III, the proprietary Methacoal technology was also evaluated. The Methacoal technology results in a very stable slurry that should not settle even during pipeline shutdown, and that can be pumped over rugged terrain. Also, some conversion of coal to liquid product in the pipeline could occur. These advantages could make Methacoal an attractive slurry technology.

PSI obtained Methacoal samples from Mr. Leonard Keller as a basis for characterizing its properties. Mr. Keller assisted in preparing flowsheets for slurry preparation and separation, and separation tests were conducted. The evaluation was based on the use of bone dry coal and undistilled crude methanol. This assumption should maximize conversion of coal to liquid and slurry stability at the expense of higher pumping cost.

Based on the same throughput and solids concentration parameters as used in the study of the conventional coal/methanol slurry of Stage II, the Methacoal system can be compared to the conventional slurry as follows:

- Neither the Methacoal samples nor the conventional sample exhibited thixotrophy. However, due to the relative non-settling characteristics of Methacoal, it may be possible to pump Methacoal in laminar or plug flow.

- Due to the finer grind of Methacoal, the coefficient of rigidity (viscosity) and yield stress are much higher than a conventional slurry. However, little settling occurs, and it is anticipated that the Methacoal slurry can be shut down for extended periods.

- The Methacoal pipeline size chosen was 24 inch O.D. for economic reasons due to rheological properties. This required 14 pump stations versus 8 pump stations and a

12.25 inch O.D. pipe with conventional slurry. However, the pipeline route distance is 2% shorter than the conventional slurry route.

- The pipeline corrosion rates are similar in magnitude. The preparation facilities are similar, but more grinding is required for Methacoal. The Methacoal slurry was separated by evaporation and condensation of methanol, whereas the conventional slurry was separated by centrifuges, with coal drying by clarification and filtering of methanol liquid. Other pipeline facilities and personnel would be similar for both slurries, but the requirements for Methacoal are higher because of the increase in pump stations and more intricate processing plants.

- No significant conversion of coal to liquids was observed in either case.

The capital cost estimate for the Methacoal slurry as developed by PSI is shown in the table below ($ 1981 millions):

Direct Costs		
Right-of-way and Lands		$ 10.36
Pipeline		228.06
Materials	158.52	
Installation	69.54	228.06
Pump Stations		71.60
Tankage		1.50
Slurry Preparation Plant		20.11
Other Facilities		25.57
Sales Tax		7.59
Total Direct		$396.69
Indirect Cost Allowance		
Engineering, Procurement and Construction Management		$ 39.67
Contingency		39.67
Total Indirect		$ 79.34
Total Direct and Indirect		476.03
Owners' Costs (a)		5.00
Interest During Construction		57.00
Total Capital Costs		$538.03

The annual operating costs of the system are estimated at \$17.151 million/year, including energy (\$9.867 million/year), labor (\$2.975 million/year) and supplies (\$40.309 million/year). Allowing 16% of the capital for yearly capital charges (\$86.08 million/year) yields a transportation tariff of \$32.54/ton of coal and 10.8¢/gallon of methanol.

The results obtained for both the conventional and the Methacoal slurries are contained in the table below:

CAPITAL COSTS - \$1,000	Stage II - Conventional Coal/Methanol Slurry	Stage III Methacoal Slurry
Direct and Indirect Capital Costs	\$ 275,950	\$ 476,030
Methanol Storage Inventory	6,430	--
Owner's Costs (Permits, etc.)	5,000	5,000
Interest During Construction (12% of Direct and Indirect Costs	33,110	57,120
TOTAL PROJECT COST	\$ 320,490	\$ 538,150
TRANSPORTATION COSTS - 1,000/yr.		
Capital (16% yr.)	\$ 51,278	\$ 86,104
Operating Costs	12,617	17,151
TOTAL TRANSPORTATION COST	\$ 63,895	\$ 103,255

TRANSPORTATION TARIFFS

Total Transportation Costs	\$ 63,895,000/yr.	\$ 103,255,000/yr.
Total Tons Moved	3,173,000 tons/yr.	3,173,000 tons/yr.
Total Cost/ton	\$ 20.14/ton	\$ 32.54/ton
Methanol Transportation Cost (52%)	\$ 33,225,000/yr.	53,693,000/yr.
Gallons Methanol Moved	495.2×10^6 gal/yr.	495.2×10^6 gal/yr.
Methanol Cost/Gal	6.7¢/gal	10.8¢/gal

On the basis of the PSI evaluation, it appears possible to achieve a stable coal/methanol slurry with the Methacoal technology, but the rheological properties and hence, pumping requirements, are adversely affected. The estimated initial investment and transportation costs are over 60% more than a conventional coal/methanol slurry, and are not offset by the benefits of the Methacoal technology. Although the rheological properties of the Methacoal slurry could be improved by increasing coal moisture and other means, slurry stability would probably deteriorate. As a result, it seems unlikely that Methacoal could be made to compare favorably to a conventional slurry as a transportation medium. Other benefits (eg., beneficiation) claimed for Methacoal could outweigh its disadvantages in some applications, but were not relevant for the cases studied by PSI.

Coal/Methanol Project Development Program

The work to date has indicated that pipeline transportation of a coal/methanol slurry is technically feasible. Further work is required to define the parameters, develop flow sheets, optimize the system, and revise cost estimates before pilot testing. A development program to accomplish this work is outlined below for a conventional coal/methanol slurry. This development program focuses only on the technical aspects.

The program would involve three basic parts for development and confirmation of the technical aspects of the project.

Part I - Initial Assessment and Scoping of Part II

- Define initial scenarios to be explored to resolve the coal drying and methanol distillation questions.

- Develop conceptual flow sheets and minor economic analysis to decide upon preferred alternative(s) to be studied.

- Complete scoping of Part II

Part II - Flow Sheet Evaluation and Scoping of Part III

- Conduct bench scale laboratory testing to confirm preferred slurry characteristics and define necessary vendor evaluations

- Conduct preliminary vendor testing and evaluations

- Complete preliminary flow sheet alternatives development

- Define cost estimates of alternatives and decide upon preferred engineering design(s)

- Complete scoping of Part III

Part III - Pilot Testing and Commercial Demonstration

- Conduct pilot plant evaluations and pipeline loop tests to confirm previous results, refine flow sheets, and demonstrate commercial viability.

A proposed schedule assuming four initial alternatives would be explored in Part I and one basic system would be explored along with three or four variations considered in the flow sheets in Part II. The overall program would take approximately 18 months.

It is difficult to reliably estimate costs for such a program without firm parameters established, but based on previous experience, the following estimates could be considered rough guidelines. ($1000):

Part	Estimated Base Engineer Cost	Owners, Engineers and Expenses*	Other Subcontractors Costs**	Total
I. Initial Assessment	$ 50	$ 20	$ 40	$110
II. Flow Sheet Evaluation	150	25	20	195
III. Pilot Testing and Commercial Demonstration				
Design & Testing	275	125	50	450
Materials & Construction	-	550	-	550

PLANT DESIGN			4.12	
Part III Total	275	675	50	1,000
TOTAL	$475	$720	$110	$1,305

* Rough Estimates of Owner's In-House Costs

**Rough Estimates of Cost connected with other Engineering Firms concerned with Project

CHAPTER V COST ESTIMATES

Based on the design parameters discussed in Chapter IV and detailed in Appendix A, the total estimated cash costs of the 5,000 ton per day plant in current dollars is $1.880 billion. Plant operating costs at the time of startup (November 1986) are estimated to be 23.9 cents per gallon of methanol, and coal costs are estimated at 30.2 cents per gallon.

Using data provided by KBW for the plant itself, ETCO developed these cost estimates by first establishing total facility costs in mid-1981 dollars as follows:

		Facility Costs (millions)	
Methanol Plant			
Coal Handling		$ 21.4	
Coal Preparation & Feeding		99.9	
Gasification & Heat Recovery		92.9	
Gas Cooling & Cleaning		79.8	
Primary Compression		49.0	
Raw Water Treatment		11.1	
Effluent Treatment		29.9	
Auxiliary Steam Generation		98.1	
General Facilities		66.9	
Air Separation Plant		121.5	
	Total	$ 670.5 (a)	$ 670.5
Turnkey Subcontracts			
Acid Gas Removal			
CO Shift			
Methanol Synthesis			
Sulfur Recovery			
	Total	$ 320.0 (a)	$ 320.0
Ancillary Facilities			
Plant Site Purchase		$ 1.0 (b)	
Evaporation Pond Purchase		1.0 (b)	
Water Supply Pipeline		2.6 (c)	
Secondary Highway to Site		2.6 (c)	
Telephone Line to Site		.2 (c)	
Power Lines to Site		2.1 (c)	
	Total	$ 9.5	$ 9.5
	TOTAL FACILITY COST		$1,000.0

(a) KBW Estimate
(b) Grace Estimate
(c) ETCO Estimate

These mid-1981 facility costs were then escalated through the construction period. Interest during construction, working capital, and other costs were added to establish total project cash costs in current dollars. The table below shows these calcuations:

Methanol Plant Construction	July 1981 $ (millions)	Inflation Factor	July 1986 $ (millions)
First Year	$ 9.0	8%	$ 9.7
Second Year	134.0	17%	156.8
Third Year	421.0	26%	530.5
Fourth Year	342.0	36%	465.1
Fifth Year	94.0	47%	138.2
	$1000.0		$1300.3

Interest During Construction

	Cash Expend.	Yrs	Interest Rate 15% Compound	Interest	Adjusted Cost
First Year-2nd Half	$ 9.7	3.75	69.3%	$ 6.7	$ 16.4
Second Year	156.8	3.00	52.1%	81.7	238.5
Third Year	530.5	2.00	32.3%	171.3	701.8
Fourth Year	465.1	1.00	15.0%	69.8	534.9
Fifth Year-1st Half	138.2	.25	3.8%	5.3	143.5
TOTAL INTEREST				$334.8	$1635.1

Methanol Plant Cost	$1635.1
Contingency @ 10%	163.5
Total Methanol Plant Cost	1798.6
Plus: Thornburgh Reservoir (a)	15.0
Project Management (b)	1.0
Working Capital (c)	65.3
TOTAL PROJECT CASH COSTS	$1879.9

(a) The Thornburgh Reservoir cost has been separately estimated by Grace.

(b) Includes market development, project financing, government regulatory process, and general management.

(c) 50% of annual operating costs.

COST ESTIMATES 5.3

Operating costs provided by KBW and coal costs provided by Grace were escalated at 8 percent to develop the current dollar level at the start of operation, as shown below:

Plant Production Costs	November 1981 $		November 1986 $	
	$M/Yr	¢/Gal	$M/Yr	¢/Gal
Chemicals	$ 788			
Catalysts	3,559			
Electricity & Propane	19,110			
Water (b)	--			
Labor	8,403			
Fringe Benefits (c)	2,522			
Operating & Maintenance Supplies (d)	30,745			
Insurance & Local Taxes (e)	15,000			
Sulfur Credit (f)	(743)			
TOTAL	$79,384			
Add: Contingency at 10%	7,938			
TOTAL PRODUCTION COSTS	$87,322	16.3¢	$128,363	23.9¢
Coal Costs				
4,405,170 tons/year @ $25/ton	$110,129	20.5¢	$161,890	30.2¢

(a) An inflation adjustment of 1.47
(b) Water Supply Capitalized
(c) ETCO Estimate
(d) 3% of Plant Cost
(e) 1.5% of Plant Cost
(f) 7,425 long tons/yr @ $100/LT

CHAPTER VI MARKET ANALYSIS

To proceed with the construction of the Chokecherry Project, it will be essential to assure in advance the sale of a sufficient portion of its 537 million gallons per year of methanol production on terms which will allow for leveraged financing of the project.

Coal-sourced methanol has three markets: (1) as a substitute for gasoline in the transportation sector, either as a blend for octane stretching or as a neat fuel with modification of Otto cycle and diesel engines; (2) as a substitute for natural gas-sourced methanol in the existing 1.2 billion gallon per year chemical market; and (3) as a substitute for No. 2 distillate for utility turbine use. The following sections discuss each market in detail.

In summary, we estimate the national market for methanol will grow by nearly 14 percent per year between 1980 and 1990. Exhibit 3 summarizes this estimate, and shows that the fuels market will account for the bulk of the market growth. This exhibit also shows that the Chokecherry project production would be about 28 percent of total methanol demand in 1985. Thus, the project would have to capture a large share of market in its first years of operation.

However, this project could not economically serve the entire national market, especially for fuel uses. ETCO has estimated the markets available to the Chokecherry Project to total about 800 million gallons per year, as follows:

Market	1985 Demand (million gallons per year)
Chemicals (U.S. National Alcohol Fuels Commission estimate)	425
Fuel	
Gasoline Blends (ETCO estimate)	282
Neat Fuel for Fleets	
California (5% of total)	72
Colorado (5% of total)	2
Utility Peaking Units (U.S. National Alcohol Fuels Commission Estimate)	25
	806

The 5,000 ton per day plant would have to capture 66 percent of this market to sell its entire production. Since the above estimate assumes that the chemical and utility markets could be served nationally from the project, the available market could be lower and the required share higher. Also, the automotive market available to the plant is only about two-thirds of the annual production.

Grace believes it is unlikely that this market share could be obtained with sufficient certainty to finance the fullscale plant. For this reason, the preferred strategy is to build an initial module with one KBW gasifier to produce about 675 tons per day of methanol, or 67 million gallons per year. This initial module would need only an 8 to 10 percent share of market to sell its entire production. The plant would have to obtain only a 19 percent share of the automotive fuel market.

Grace has separately funded a study of the economic and technical feasibility of the initial module. This Stage IV study concluded that the initial module is feasible.

AUTOMOTIVE FUEL MARKET

Under this section we analyze the potential for methanol as an automotive fuel in three general categories:

- As a blend with unleaded gasoline
- As a neat automotive fuel (or with a minor addition of unleaded gasoline or other liquid hydrocarbons)
- As a liquid hydrocarbon for fuel cell powered electric drive vehicle

Methanol/Unleaded Gasoline Blends

Recently completed tests by the Bank of America in California have established the advantages of methanol in a 4% blend with unleaded gasoline for use in unmodified vehicles. The results showed a 13% increase in fuel economy (miles per gallon), no increase in maintenance costs, and a reduction in operating costs of 1¢/mile. In addition, the blend showed decreased exhaust emissions. The test also confirmed practical logistics to assure fuel quality and worker health and safety. These results, combined with the lower cost of methanol compared with unleaded gasoline, suggest that the use of a 4% blend of methanol in unleaded gasoline would be an excellent entry into the automotive fuel market.

The most economical opportunities for the Chokecherry Project's marketing of methanol as a gasoline additive are found at refineries and terminals in the western U.S. The major refineries in this area are listed in Exhibit 4. If it assumed that: (1) gasoline production is 60% of the total operating crude capacity of 2.27 million barrels per day in these refineries; (2) 75% of gasoline production is unleaded in 1985; and (3) methanol is blended at 4% in half this volume to increase octane, then the 1985 market for methanol in the gasoline from these refineries would be 856,000 gallons per day or 282 million gallons per year. The production for the Chokecherry Project is 90% greater than this quantity so other markets must also be developed. These refineries are, however, the principal methanol blend markets for the Chokecherry Project's initial production.

Straight Methanol Fuel

Although methanol contains approximately one-half the Btu's per gallon of gasoline, its high octane number allows a higher compression ratio, greatly increasing the thermal efficiency of the engine in use. Theoretically, at an 18 to 1 compression ratio, methanol could have nearly double the thermal efficiency of gasoline, thereby providing equal miles per gallon in a given automobile.

There are also substantial benefits in the use of methanol in terms of reduced pollution. At an 18 to 1 compression ratio, there is almost complete combustion of hydrocarbons. Tests to date would indicate that atmospheric emissions would be on the order of 5% to 10% of those anticipated with gasoline in the same engine. Also, the problem of evaporative emissions in the carburetor would be eliminated with the use of straight methanol.

Bank of America Program

To demonstrate the use of methanol as a practical automotive fuel, the Bank of America has undertaken a program to convert up to 2,500 or their fleet of cars to methanol by 1983. To date, the bank has converted 146 standard Ford cars at a cost of approximately $1,500/per car and has ordered 100 more. This conversion calls for replacement of some of the materials in the fuel system that are not compatible with methanol, carburetor and timing adjustments, and an increase in compression from a ratio of about 8 to 1 approximately 13 to 1.

The Bank of America is now using a fuel called Methanol X which contains about 90% methanol with the balance largely unleaded gasoline. According to Merle Fisher, Director of Fleet Operations for the Bank, they are paying $0.88/per gallon for methanol or 77% of the price of $1.15/per gallon for unleaded premium gasoline. Miles per gallon with methanol is approximately 85% of that with gasoline, so the Bank is reducing fuel costs with each conversion. Further, the Bank expects to recover its investment through reduced maintenance because the engine operates at a substantially lower temperature, assuring longer engine life, and there is no carbon build-up.

The Bank of America is convinced that methanol is economically justified today as an automotive fuel and will become increasingly so with further increases in the price of gasoline.

California Energy Commission Program

The California Energy Commission has earmarked $2 million in 1981-82 for an Alcohol Fleet Test Program. This program consists of three different types of vehicles utilizing captive fleets as the basis for testing the vehicles in a regular duty high mileage typical fleet operation. The fleet vehicles are summarized in the table below. All vehicles operate on neat fuels.

ALCOHOL FLEET TEST PROGRAM

Fleet	Fuel/Vehicles			
	METHANOL[a]	Ethanol[b]	Gasoline[c]	Total Vehicles
1. Ford Pinto	4	4	4	12
2. VW Rabbit	10	11	7	28
Pickup	8	8	6	22
3. Ford Escort	40	0	10	50
TOTALS	62	23	27	112

(a) Methanol fuel has 5% Iso Pentane added to aid in starting.

(b) Ethanol Fuel is denatured with 5% unleaded gasoline.

(c) Control Fleet uses unleaded gasoline.

Fleet one is a retrofit program which utilized existing gasoline vehicles which were new but had been purchased as gasoline vehicles. The purpose for this fleet was to evaluate a quick, after-market conversion of existing in-service vehicles. Conversion cost ranged from about $1,200 for low-compression-ratio, minimum conversions, to about $1,800 for high-compression-ratio conversions.

The emphasis of the Fleet Program is on Fleets Two and Three which involve major automotive manufacturers with a goal of achieving a mass production type vehicle to reduce the large custom conversion cost. Both of these fleets were configured with that goal in mind.

On July 8, 1981 the VWoA production facility at Westmoreland, PA produced thirty-seven VW Rabbits and pickups on the assembly line interspersed with their regular production of gasoline and diesel vehicles. The production run was successful and represented the first time that alcohol vehicles had been produced on an assembly line in the U. S.

The Ford Escorts are equally capable of being assembled in this fashion. These methanol vehicles are being engineered by the Ford factory and converted locally in the Los Angeles area. The Escorts will be a part of the LA County motor pool which will operate these vehicles under contract with the CEC. Ford provides engineering and emission testing.

Fuel for all three fleets is provided by Douglas Oil (a wholly owned subsidiary of CONOCO). Five service stations have been adapted with special tanks, pumps and hoses to distribute fuel, both methanol and ethanol, to fleet vehicles.

The goal of these programs is to meet 1983 California Air Resources Board (CARB) standards, 1985 federal fuel economy standards, and to satisfy such fleet requirements as durability, cold start acceptability, and drivability.

Other California Fleets

Firemen's Fund, a San Francisco Insurance Company, and Pacific Telephone and Telegraph have recently begun straight methanol fleet demonstration programs. Both firms plan to convert 10 vehicles initially. Firemen's Fund will be using five sedans and five vans used in the company's carpool program.

In addition to the use of straight methanol, the San Francisco Chronicle and the San Francisco Examiner have announced a fleet test in which methanol represents approximately 90% of the total. The other additives are to improve starting characteristics and/or provide greater lubricity. There is considerable argument as to whether these additives are necessary, and there are those who claim that straight methanol will perform equally well.

California Fleets Summary

The test programs for methanol-fueled fleet vehicles being conducted by the Bank of America, Firemen's Fund, Pacific Telephone and Telegraph, and the California Energy Commission, are the first steps in developing the West Coast transportation market for methanol. As noted earlier, initial results of the B of A program indicate that engine conversion to methanol use is both economically attractive and environmentally beneficial. We believe this combination of factors will encourage conversions of additional fleets first in California and later in Arizona, Washington and Oregon.

The California Energy Commission has provided Grace with the following breakdown of the characteristics of California fleets:

- Captive fleets account for 10% of California's gasoline use. Total fleet gasoline consumption: 1,200 MM gallons/yr Average consumption/vehicle: 804 gallons/yr.

- Fleets in California Metropolitan Areas

- Los Angeles - Long Beach	485,872 total vehicles 166,545 automobiles
- San Francisco - Oakland	518,538 total vehicles 104,881 automobiles
- Anaheim - Santa Ana	61,865 total vehicles 18,748 automobiles
- San Diego	43,000 total vehicles 9,500 automobiles

- Types of Fleets

	% of Total	No. of Vehicles
Construction/Mining	17.7	262,729
Food Manufacturing/ Distribution	16.3	241,948
Government	15.4	229,792
Lease/Rental	9.6	142,497
Manufacturing/ Processing	9.6	142,492
Retail/Wholesale Delivery	9.5	141,012
Bus Fleets	7.9	117,263
Public Utilities	5.9	86,920
Petroleum	5.3	78,133
Other	2.8	41,561
	TOTAL	1,484,347

- Fleet Owner Characteristics

66% can do major engine overhauls
85% repair carburetors and fuel system
4% use unleaded gasoline systems
94% have fuel storage tanks and pumps with an average fuel storage capacity of 14,929 gallons.

The above data indicate that the California fleet market is large and has the maintenance and storage capabilities to allow conversion to methanol with the minimum of disruption.

California Tax Incentives

In order to encourage the conversion of engines from gasoline to alcohol fuels, California Governor Jerry Brown signed a bill in the last week of September, 1981 which authorizes personal income tax credits and bank and corporation tax credits of 55% of the costs of engine conversion to fuels that are at least 85% fueled by ethanol or methanol. The maximum credit allowed is $1,000 per vehicle. The law remains in effect through 1990, and covers vehicles converted since January 1, 1981.

In a concurrent action, Governor Brown also signed a bill which sets excise taxes on ethanol and methanol blend fuels with not more than a 15% gasoline or diesel oil at one half the tax on other motor vehicle fuels. Currently, the motor fuel tax is 7¢/gallon but it may soon be raised to 9¢/gallon to provide additional street and highway maintenance for state and local governments. The new law is effective through January 1, 1980. It is our opinion that this 3.5¢/gallon tax will have a beneficial effect on California consumers as methanol will be seen to be paying its share of taxes at a rate calculated to reflect its energy content. The fact that properly converted engines will give consumers better mileage results than indicated by methanol's energy content will act as an incentive to methanol use.

Colorado Fleets

During the past year, Grace has made a study of fleet operations in Colorado and has identified the following characteristics:

Type of Fleet	% of Total	No. of Vehicles
Service/Industrial	21.5	8,256
State of Colorado	17.4	6,700
Miscellaneous	16.5	6,325
City of Denver	10.4	4,000
Utility Companies	10.2	3,930
Leasing Companies	8.7	3,326
U.S. Government	8.7	3,300
Truck Rental Companies	5.8	2,246
Taxis	.8	363
TOTAL	100.0	38,446

Total estimated fleet gasoline consumption: 30.7 million gallons/year

p

A number of Colorado fleets have run demonstration programs on ethanol and methanol. To date, only the gasohol-type programs have been viewed as successful by the sponsors as no engine conversion work was done prior to testing. The U.S. Postal Service, however, began a new fleet test in October, 1981 which does involve the use of Ford Pintos with engines converted to alcohol use. The USPS test involves 10 neat methanol cars and 10 neat ethanol cars. To date, 3 methanol and 3 ethanol cars are running, and the test program is set to begin about December 1. The compression ratios of the cars have been increased to 12:1 by milling the heads, and a number of other changes have been made in the fuel system, in timing. John Williams, Supervisor of Fleet Operations for USPS in Denver, is encouraged by the performance of the first few cars and looks forward to a successful test program.

Alcohol Engine Developments

There are several companies now developing an alcohol engine for use with straight methanol or ethanol. Nissan Motors in Japan, producer of the Datsun, is perhaps ahead of any company in the U.S. in this effort. We anticipate that Nissan will soon be prepared to move forward with the production of such an engine once the market has been established. Volkswagen (VW) in Germany has also been active in this area and is ahead of Nissan Motors in actual engine production. This is the result of pressure applied by the government of Brazil to force engine manufacturers in that country to develop an alcohol engine. Volkswagen appears to be the leader in the Brazilian effort.

Fuel Cell/Electric Drive Vehicles

A project being developed at the Los Alamos Scientific Laboratory shows great promise for an electric drive car powered by a fuel cell using methanol. This program is largely dependent on the continued improvement of the fuel cell through increase in the power/weight density and reduction in cost. However, these problems appear to be susceptible to straightforward engineering developments without need for a basic technological breakthrough.

Current tests are based on the use of a fuel cell utilizing phosphoric acid as the electrolyte with a platinum catalyst. A program for use of this type of fuel cell based on methanol is being considered for urban electric drive buses. This could prove to be commercially viable based on the current state of the art with an anticipated 37.5% thermal efficiency from methanol to wheel compared with about 20% for a gasoline or diesel fueled internal combustion engine. An anticipated 20% increase in total cost for the fuel cell-electric drive bus should be more than offset by lower fuel costs, reduced maintenance, higher reliability, and extended vehicle life. In addition, it offers the intangible benefits of a lower sound level and an almost complete elimination of atmospheric pollution.

Somewhat further ahead is the promise of still greater economies through development of an alternative electrolyte such as triflic acid (tri-floro-methane sulfonic acid). This could double the power/weight density and increase the thermal efficiency to 45-50% if laboratory test results can be validated on a commercial scale. This development will have no near term impact on the market for methanol but could become a significant factor in the late 1980's.

Summary

The automotive fuel market is the most attractive long term market for methanol, since the efficiency of methanol use in this market creates a value at least equal to that of unleaded gasoline. However, the use of neat methanol will be relatively slow to develop because of changes required in engines and other components. The blend market, while smaller than the ultimate potential neat market, is easier to enter and sufficiently large to sustain the initial production module.

CHEMICAL MARKET

The chemical market for methanol is well-established as a feedstock for formaldehyde, acetic acid, and other intermediates. It amounted to a total of 1.1 billion gallons in 1980.

Dupont estimates that methanol demand will grow by 8 to 10% per year between 1981 and 1985, primarily on the strength of new consuming facilities for the production of acetic acid and MTBE.(a) Mr. Harry B. Bartly, Jr., President of Celanese Chemical Co., expects the 3.5 billion gallon world demand for methanol in 1980 for established end uses to grow by more than 5% per year. He expects the 420 million gallon demand in 1980 for emerging end uses to grow to 1.5 billion gallons by 1990, a growth rate of 14% per year. U.S. demand should experience similar growth rates.(b) (The Celanese estimate of a 1990 market of 24 million tons/yr. compares with the more recent Chem Systems, Inc., estimate of 27 million tons/yr.)

(a) Chemical Marketing Reporter, October 6, 1980, p. 15
(b) Oil and Gas Journal, April 21, 1980, p. 34

The ability of current suppliers to meet this demand is not clear. The only new major plant that is planned to start production before 1982-83 (Dupont's Deer Park, Texas plant) may meet only half of the 10% increase that is expected in U.S. demand in 1980. Arco Chemical Co. is planning a 200 million gallon per year plant on the Gulf Coast for initial operations in 1983. Other companies planning smaller expansions include Borden, Allemania, and Tenneco.(c)

Although the recent economic slowdown has brought temporary downward pressure on U.S. methanol prices, the longer term trend is upward because of both growing supply/demand imbalances and increasing prices for natural gas feedstocks. Prices can be expected to continue to rise as fast as deregulated natural gas prices which are scheduled to increase by 4% a year above the inflation rate from 1980-1985.

We anticipate that methanol will be produced from coal at lower costs than from new natural gas feedstocks by 1985 when the proposed plant would be in production. Thus, methanol from the Chokecherry Project could, if necessary, be sold as a chemical feedstock in the open market. This market is not as attractive as the automotive market, but serves the purpose of backstopping the emerging automotive market.

UTILITY MARKET

Methanol has several uses in the utility market, all of which are technically feasible. The simplest is direct firing of methanol under a boiler. In the absence of extraordinary circumstances, however, this application is not economically attractive because it puts a high value liquid product to low value use. For this reason, we concentrate here on two other applications in which the value of methanol is considerably higher.

Combustion Turbines

Methanol is an ideal fuel for use in combustion turbines. All major turbine manufacturers (General Electric, Westinghouse, and United Technologies) have informed us that they are prepared to sell methanol-fueled turbines on standard price, delivery, and warranty terms. The acceptability of methanol to the utilities themselves was confirmed by a 500-hour test conducted by Southern California Edison early in 1980, which showed that methanol is both at least as efficient and clearly less polluting than petroleum-based fuels.

(c) Chemical Marketing Reporter, March 3, 1980

As a turbine fuel methanol can be used in a combustion turbine combined cycle plant to produce intermediate load power. In this application, the waste heat from the turbine fires a boiler to raise steam for additional power production, thereby substantially increasing the overall generating efficiency above that obtainable by a combustion turbine alone. Because combustion turbine combined-cycle plants are generally large (over 100 Mwe) and are in operation for 10-12 hours per day, they represent a large potential methanol market. If, as we expect, methanol fuel finds its highest value market as an automotive fuel, it may be priced out of the intermediate load market for electric utilities. Southern California Edison has expressed serious concern that methanol prices will rise to equivalency with unleaded gasoline.

Combustion turbines are also used to supply peaking power. The market is smaller than the intermediate load market because the units are smaller, and power production is required for only a few hours a day. On the other hand, utilities assign a high premium to the security of supply of peaking fuel because peak power must be available at a moment's notice. For this reason, and because peaking fuel is not a large part of the total fuel bill, we believe that methanol will find a significant market in this application. According to the U.S. National Alcohol Fuels Commission, the market could reach a level of about 500 million gallons a year nationwide by 1990. As shown on the following table, the market for peaking fuels in the western U.S. is sizeable:

Western Utility Peaking Unit Energy Purchase Data for the Period March 1980 - February 1981

	(BTU Billions)			(Million Gallons)
State	Oil	Gas	Total	Methanol Equivalent
Arizona	327.6	7,085.2	7,412.8	123.5
California	12,920.0	6,421.5	19,341.5	322.4
Colorado	486.0	4,303.2	4,789.2	79.8
Kansas	260.3	2,701.9	2,962.2	49.4
Nebraska	-	13.6	13.6	.2
Nevada	-	2,552.6	2,552.6	42.5
New Mexico	-	947.7	947.7	15.8
Utah	-	-	-	-
Wyoming	.6	-	.6	-
TOTALS	13,994.5	24,025.7	38,020.2	633.6
CHOKECHERRY ANNUAL PRODUCTION				536.6

Fuel Cells

The fuel cell is an electro-chemical device for producing power virtually free from environmental pollution and with very high efficiency. Methanol is the most attractive hydrocarbon fuel for fuel cells because it increases operating efficiencies by approximately 15% and reduces initial capital costs by some 10% in comparison with any other fuel.

Fuel cell technology is in the early stages of commercialization. ETCO has served as an advisor to the Electric Power Research Institute on the problems of commercializing fuel cells, and R.W. Fri of ETCO serves as Executive Director of the Fuel Cell User Group of the Electric Utility Industry. On the basis of our close involvement with fuel cells, we believe that the market for methanol for this purpose will grow rapidly. Methanol is a fuel with special qualities that justifies as a price in fuel cell operation higher than the Btu equivalent price for No. 2 Distillate, and thus fuel cells could become an attractive market for methanol in five to ten years.

Summary

We have discussed the utility market for methanol with officials of Southern California Edison (SCE). They recognize the advantages of methanol for gas turbine combined-cycle plants and ultimately for fuel cells. SCE has completed a 500-hour test of methanol in a gas turbine with excellent results and is among the utilities most interested in fuel cells. They have just published an expansion plan for the coming decade which includes 150 megawatts of fuel cell capacity with methanol recognized as the preferred fuel. While they see methanol as competitive with No. 2 Distillate at the present time, they anticipate that the growing market for methanol as an automotive fuel could move the price up to the level of unleaded gasoline. This move would alter significantly the economies of the use of this fuel for power generation, and could limit its use for base of intermediate loads. Methanol remains an alternative fuel for peaking turbines, however, because utilities are willing to pay a security premium for this application.

CHAPTER VII ECONOMIC AND FINANCIAL ANALYSIS

Cash flow projections have been prepared using the cost estimates developed above and a revenue forecast created for the chemical market. Grace believes a revenue forecast based on the chemical market to be a conservative approach as the forecast price is lower than the forecast price of methanol in the developing automotive fuel market. On this basis, the cash flow assumptions used in the economic analysis, and the result of the economic analysis, are discussed below.

REVENUE FORECAST

The November, 1981 price of methanol in the chemical market is $.75 per gallon. For the cash flow projections, this price was escalated by an assumed inflation rate of 8% per year to the mid-year of each operating year. The mid-year price was used as the average price for each operating year. This escalation brought the methanol price to $1.14 per gallon in April, 1987, the mid-year date of the first operating year.

The KBW study indicates that the initial production is scheduled for November, 1986. The testing and start-up process is assumed to permit production at a level equal to 25% capacity in the first operating year (148 million gallons) with an increase to a level equal to 50% capacity in the second operating year (297 million gallons). Full production (90% capacity) is assumed for the third operating year and beyond.

OPERATING AND COAL COST FORECASTS

Grace estimated a coal cost of $25/ton (November 1981$). This is the coal price quoted in recent long term contracts in the Craig vicinity. The November, 1981 operating and coal cost estimates have been escalated by an assumed inflation rate of 8% per year to the mid-year of each operating year. During the testing and start-up period of the first and second operating years, 100% of the operating costs were assumed, while coal costs were reduced to match the 25% and 50% average production levels.

FINANCIAL ASSUMPTIONS

Grace has developed profit and cash flow projections for the Chokecherry Project based on the following assumptions regarding project financial structure:

A. Project Investment: ($ Millions November, 1986)

TOTAL INVESTMENT $1,879.9

B. Project Financing: ($ Millions November, 1986)

1) Partnership Interests: 30% ($564)

2) Bank Loan: 70% ($1,315.9)

Term: 20 years
Interest: 15%
Retirement: 20 equal annaul installments of $210.2 million.

C. Interest During Construction

First Year Interest	$ 6.7
Second Year Interest	81.7
Third Year Interest	171.3
Fourth Year Interest	69.8
Fifth Year Interest	5.3
TOTAL INTEREST DURING CONSTRUCTION	$334.8

This interest is capitalized and amortized over the first 10 years of operation.

D. Government Tax Calculation: ($ Million Nov., 1986)

1) Depreciation of Plant and Facilities

Facility	(1981 $ Millions) Cost	Escalator	(1986 $ Millions) Basis	Schedule
Structure	$ 38.6	1.08	$ 41.7	15 yr, 175% Declining
Methanol Plant	830.4	1.33	1,105.1	5 yr, ACRS*
Oxygen Plant	121.5	1.17	142.2	5 yr, ACRS*
Plant/Pond Sites	2.0	--	--	Not Depreciated
Roads/Utilities/Pipeline	7.5	1.24	9.3	15 yr, 175% Declining
Thornburgh Reservoir	15.0	1.00	15.0	15 yr, 175% Declining

*Accelerated Cost Recovery System of The Economic Recovery Act of 1981.

2) Investment Tax Credit

Facility	Base	10% ITC
Structure	$ 41.7	$ 4.2
Methanol Plant	1,105.1	110.5
Oxygen Plant	142.2	14.2
Roads/Utitlites/Pipelines	9.3	.9
Thornburgh Reservoir	15.0	1.5
		$131.3

The ITC is assumed to be taken in the first year of serivce.

CONCLUSIONS

Using the above assumptions, which Grace believes to be conservative, the cash flow projections result in 20-year internal rates of return (IRR) on equity of $545 million of 31.28 percent in current dollars and 21.55 percent in constant dollars. The detailed cash flow projection is continued in Exhibit 5. Thus, Grace concludes that the 5,420 ton per day methanol plant would generate sufficient cash to cover all operating, feedstock, and debt service costs in addition to providing an attractive return on the equity investment on the assumption that the entire production could be marketed to the chemical industry.

It is, however, very doubtful that an amount of methanol equivalent to 39% of 1985 U.S. production could be successfully sold into the chemical market. This analysis strengthens the Grace plan to build the plant in stages to match the expansion of the chemical market and the development of an automotive fuel market.

p

CHAPTER VIII SITE SELECTION

A major purpose of the Stage III study was to select a specific site for the coal-sourced methanol plant. During Stage I, the Axial Basin of northwest Colorado was identified as the most promising area for the plant, since this area is near the center of gravity of present and future coal production. It is also isolated from environmental impacts arising from the oil shale developments to the south, and power plant construction to the north along the Yampa River. The Stage II work confirmed the selection of the Axial Basin location from an engineering and economic standpoint, but did not analyze the site specific environmental considerations in significantly more detail than was done in Stage I.

As a result of the work conducted in Stage III, a site covering Section 29 South and Section 32 North, T5N R93W, was selected. This site, shown on the map at Exhibit 2, is favorably situated for both the initial module and subsequent expansion, and appears to minimize the environmental impact associated with plant construction and operation. Grace has secured options for surface rights for both the selected site and the surrounding area.

The site selection procedure followed by Grace is documented in the Espey-Huston & Associates, Inc. report attached as Appendix D. The balance of this chapter summarizes the site selection process and the basis for selecting the final site.

SITE SELECTION PROCESS

Based on the work done in Stage I and Stage II, Grace selected four alternative sites in the Axial Basin for consideration in the Stage III study. As shown on Exhibit 6, three sites (Sites 1, 2 and 3) were near the transportation facilities represented by the Colowoyo rail spur and State Highway 13. Site 4 was located approximately 5 miles to the west, more distant from transportation but also more distant from the associated air emissions at the other sites.

During Part I of the environmental analysis program, Grace asked each of its environmental subcontractors to make a preliminary evaluation of each site based on available data and field observation. Each subcontractor then assigned a point score to each site for each of several factors relevant to its area of analysis. The final scores thus assembled are shown in Exhibit 7.

Grace analyzed these scores, using 5 different statistical techniques as documented in the Espey-Huston report. In every case, Site 4 appeared to be the best location for the plant based on environmental considerations. Although additional transportation costs of 16 to 54 cents per ton of coal were associated with this more remote site, the costs were not sufficiently great to outweigh the environmental benefits.

On June 4, 1981, Grace sponsored a tour of all four sites for local governmental officials and the public, and presented its site selection analysis in a public meeting. Since no significant issues were raised, Grace then concentrated on selecting a specific 160-acre site in the area of Site 4.

Further analysis of the Site 4 area indicated that the best location would be near the centerline of the Axial Basin, about two miles northeast of the Site 4 location used in the Part I study. This change, which moved the site farther from the Danforth Hills on the south rim of the Basin, both improved the dispersion of air emissions and reduced the likelihood of impact on sensitive wildlife and vegetation species. Final adjustments were made to minimize local impacts on Sage Grouse strutting grounds in the vicinity, resulting in the selection of the site shown on Exhibit 2.

The final site is on private property under option to Grace, and is accessible to coal, water, power, and roads through corridors that do not cross federal lands.

BASIS FOR SITE SELECTION

The major findings regarding each alternative site, and the basis for selecting the Site 4 area, are summarized below.

Site 1. This site had a fatal flaw because the high background of total suspended particulates (TSP) would probably prohibit plant construction. The TSP background is created by Northern Coal's proposed Milk Creek loadout, the Colowyo mining and loadout operations in the vicinity, and traffic on State Highway 13. For this reason, Site 1 was not considered further, although its other environmental characteristics were generally favorable.

Site 2. This site was rated as second choice behind Site 4. It did not suffer from the TSP background problem of Site 1, although its proximity to Duffy and Iles Mountains could cause local violations of sulfur oxide and nitrogen oxide standards. The site had no significant drawbacks from an ecological perspective, and was determined to be the least likely site to contain cultural artifacts. However, the site was closer to major surface drainages and groundwater acquifers than Site 4.

Site 3. This site was the least attractive one. It presented the same potential air quality constraint as Site 2. Site 3 was also closer to a possible concentration of sensitive wildlife species than the other sites, and was judged most likely to contain cultural artifacts. The site was also susceptible to occasional flooding.

Site 4. This site had the lowest background levels of air emissions of any site, and, after its final location in the center of the Axial Basin, the best dispersion characteristics as well. It is more distant from major drainages and groundwater acquifers than the other sites. Some potential for sensitive wildlife or vegetative species was indicated in the Part I studies, but the final site location is in an area of cultivated land, thereby reducing this possibility. Similarly, detailed investigation of the site has revealed no cultural artifacts of importance.

Socioeconomic and hazardous waste impacts were also evaluated for each site. These impacts did not prove to be site specific, and therefore were not a major factor in site selection.

CHAPTER IX ENVIRONMENTAL IMPACT

During Part II of the environmental assessment, the key environmental issues identified for the selected plant site were analyzed. The analyses were performed by subcontractors with expertise in each important discipline, and the results of their work are summarized in this chapter.

Based on these analyses, Grace believes that both the initial and full-scale plants can be constructed in compliance with all applicable environmental requirements. Briefly:

1. Air emissions for both plants meet both Prevention of Significant Deterioration and National Ambient Air Quality standards. Emissions from the small plant are sufficiently low that permit processing can begin before background monitoring is complete.

2. The plants will not discharge wastewater, and so no impact on surface waters is expected. Local soils can be compacted to achieve permeabilities low enough to control infiltration from evaporation ponds or accidental spills into local groundwaters.

3. Most solid waste from the plant need not be disposed of as a hazardous waste. Spent catalyst will be disposed of as a hazardous material, but only once every two to four years. Solar evaporation pond sludges will be isolated in the ponds and ultimately stabilized in place.

4. There are no threatened or endangered acquatic species in the streams near the plant. Since no wastewater discharge is expected, little if any impact on aquatic biology is expected. Similarly, no threatened or endangered species of vegetation are present near the site, and the vegetation found there is not sensitive to the expected air emissions.

5. Terrestial wildlife will be affected primarily by direct mortality during plant construction and operation (e.g., road kill, electrocution) and from disturbance of habitat surrounding the plant site. There are threatened or endangered wildlife species in the general area, although the plant site is not a preferred habitat for them. Intrusion into a Sage Grouse strutting ground is possible. Insofar as these impacts are known, adequate mitigation measures appear to be available.

6. Impacts on soils and cultural resources are minor.

AIR QUALITY

The proposed plant site is located in an area subject to Prevention of Significant Deterioration (PSD) regulations. The site is categorized as Class II PSD region, which limits the amount of air pollutants that can be emitted. In addition to meeting the PSD requirements, the emissions from the plant cannot violate the National Ambient Air Quality Standards (NAAQS) in any case.

Grace retained Enviro-Test, Ltd. to analyze the air quality impacts of the plant, to determine whether the plant complied with PSD and NAAQS requirements, and to determine the need for a baseline air quality monitoring program. The Enviro-Test report was designed to contain essentially all the information required for a PSD permit to facilitate review of air quality impacts by Federal and state regulatory agencies. Since the PSD permit application is expected to request a phased-construction permit (see Chapter XI), the consultant's report analyzes both the 675 ton per day initial module and the 5000 ton per day full scale plant. The Enviro-Test report is attached as Appendix E.

The air quality study was based on an emissions inventory developed by the Koppers Company from material balances prepared for both plants. Each emissions source was analyzed to estimate reasonable removal rates for control technology. No formal analysis of Best Available Control Technology (BACT) was performed for this plant, but data for a comparable plant that has received its PSD permit were used. Meteorological data for the site were developed by the transposition of data collected at the Colowyo loadout and in the Craig area, using EPA methodology. The resulting emissions and meteorological data were analyzed in the VALLEY model to estimate the concentrations of pollutants surrounding the plant site. Grace believes that the results of this analysis are conservative, and that further refinements made during preparation of the final PSD application may result in lower impacts than those estimated in the Enviro-Test report.

The design basis for the two plants was essentially the same, but four differences in design and operating characteristics had a material effect on emissions.

1. Coal would be delivered via truck to the initial module and not stockpiled, tending to reduce Total Suspended Particulate (TSP) emissions.

2. Coal pulverizing and drying is combined into a single system in the initial module, significantly reducing the uncontrolled emissions from the initial module. Because particulate control is more difficult in the initial module, total TSP emissions are only slightly less than in the large plant. The single pulverizing and drying system substantially reduces gaseous emissions in the initial module, however.

3. The large plant design assumes production of carbon dioxide for use in pipeline transportation of coal, while the initial module design does not. Although this assumption leads to different emission sources for carbon monoxide in the two plants, the total carbon monoxide emissions are proportional.

4. Flue gas emissions from the auxiliary boiler on the initial module are vented through a citrate sulfur recovery system also used to recover sulfur from the acid gas removal system. This results in a very high degree of flue gas control in the initial module. The large plant auxiliary boiler is equipped with its own particulate removal and sulfur dioxide scrubber systems.

Based on the above assumptions, Grace concludes that both the initial module and the large plant will meet PSD requirements, as shown in the following table (concentrations in micrograms per cubic meter):

Pollutant	Averaging Time	PSD Standard	Highest Concentration From Initial Mod.	Large Plant
TSP	24 Hour	37	19	35
	Annual	19	2	16
SO_2	24 Hour	91	17	75
	Annual	20	3	17

Similarly, both plants meet the National Ambient Air Quality Standards (NAAQS), as shown in the following table (concentrations in micrograms per cubic meter):

Pollutant	Averaging Time	Primary NAAQS	Highest Concentration From Initial Mod.	Highest Concentration From Large Plant
TSP	24 Hour	260	19	35
	Annual	75	2	16
SO_2	24 Hour	365	17	75
	Annual	80	3	17
NO_x	Annual	100	6	43
CO	1 Hour	40,000	1,980	12,220
	8 Hour	10,000	1,485	9,165

The VALLEY model was also run to predict SO_2 concentrations resulting from plant emissions at the Flat Tops Wilderness Area, the closest PSD Class I area. The results showed no impact within 10 miles of the Area. In addition, because the Area is 35 miles from the plant and is separated from the plant by mountainous terrain, no visibility impact is expected. As discussed elsewhere in this chapter, no secondary impact on soils and vegetation is expected.

Finally, processing of the PSD permit may require collection of baseline air quality data. Plant emissions must be added to this background to determine compliance with NAAQS. Monitoring is not required, however, if concentrations of plant pollutants are so low that their additive effect would be minimal. EPA has established *de minimus* concentrations to assess whether monitoring is required.

Grace believes that the emissions from the initial module are low enough to allow processing the PSD permit without prior monitoring. Concentrations of TSP, SO_2 and NO_x from the initial module are near *de minimus* levels, as shown in the table below (concentrations in micrograms per cubic meter):

Pollutant	Averaging Time	De Minimus Level	Concentration From Initial Module
TSP	24 Hour	10	19
SO_2	24 Hour	13	17
NO_x	Annual	14	4
CO	8 Hour	575	1,482
H_2S	1 Hour	0.04	3.2

Although the CO and H_2S concentrations exceed the de minimus levels, the concentrations shown in the table appear only at one point near the northwest corner of the site. At all other points, concentrations of these pollutants are at most one-quarter of those shown above. For this reason, because the VALLEY model is conservative, and because further BACT analysis may decrease plant emissions, it appears that the potential exists for reducing most emissions below de minimus levels in the final PSD application.

Moreover, since the plant site is remote from other man-made pollution sources, low background concentrations of gaseous pollutants would be expected in the area. Background TSP concentration is estimated to be 25 ug/m^3. Thus, TSP concentration from the plant, when added to this background, still falls well within NAAQS requirements.

Finally, it is planned to initiate a monitoring program in 1982 in any case, since it will be required for large plant construction. Thus, the PSD permit for the initial plant can be processed before monitoring is complete with little risk that the initial plant emissions would exceed NAAQS levels. This conclusion would then be confirmed by monitoring results developed prior to plant construction.

HYDROLOGY AND GEOTECHNICAL

Grace retained WATEC, Inc. to conduct a study of surface water, groundwater, and geotechnical characteristics of the proposed plant site and surrounding area. Since the plant is designed for no discharge of wastewater, no direct impact on surface water or groundwater quality is anticipated. Thus, the studies were directed primarily at requiring baseline data and at identifying any issues that should be considered during plant design. The WATEC hydrology report is attached as Appendix F, and the geotechnical report as Appendix G.

Surface Water

The surface water study was designed particularly to develop baseline data on water quality and quantity for future reference during plant engineering and construction. Monitoring stations were established on Collum Gulch and Morgan Gulch above and below the plant site to collect data on stream flow. Water quality samples were also collected at these stations and analyzed. The detailed data developed in the monitoring program are contained in the WATEC report.

Groundwater

Twelve wells at eight locations along the boundary of the plant site were completed to ascertain groundwater levels and the nature of the subsurface geology. These wells were dug to depths between fifteen and thirty feet, depending on the level of bedrock. In general, the bedrock underlying the entire area is an impermeable shale that effectively isolates any major groundwaters that may be present in the Basin below the shale-layer.

Some water was encountered in the test wells, occuring principally in an underlying gravel deposit. This gravel was thickest in the upland (southwestern) portion of the site, and thinned along the downslope toward the northeast. Further studies will be required to determine whether the gravel deposit represents a buried stream channel, or simply a gravel layer over the entire area that traps infiltrating water. This study will determine whether the groundwater in the gravel is in communication with any other groundwater or surface water.

Because the soil above the gravel layer can, with proper compaction, exhibit a low permeability level, it appears that proper design and construction practices will eliminate any danger of groundwater contamination from holding or evaporation ponds at the plant site. Handling of wastewater in areas where the soil has not been compacted will be avoided to eliminate infiltration from spills.

Geotechnical

A preliminary geotechnical assessment was conducted to assess soil permeability, the mechanical properties of the soil, and the potential for geologic hazards.

The results of this work indicate that compaction of soil present at the site will result in permeabilities sufficiently low to use this material as a liner for water storage or on-site solid waste disposal. This option will therefore be pursued for construction of holding and evaporation ponds. On-site solid waste storage is not, however, anticipated at this point.

Earthquake potential in the area is moderate, as it is for the entire State of Colorado. There are no active faults in the immediate project area, nor have epicenters of any earthquakes been located in the Axial Basin since records began in 1870. Such phenomena do exist outside the basin within ten miles of the site, however. An event of magnitude VIII on the Modified Mercalli Scale is estimated to have a 200 year recurrence interval.

Grace believes that these evaluations have not identified any serious problems for plant design and construction, although detailed design must take into account these geotechnical data.

SOLID WASTE

Grace retained Espey-Huston & Associates, Inc. to analyze the solid waste aspects of the coal-sourced methanol plant, and to assess the requirements for disposing of these waters, taking into account the provisions of the Resource Conservation and Recovery Act (RCRA). The Espey-Huston report is attached as Appendix H.

Although Espey-Huston concentrated its efforts on solid waste generation and disposal, all waste streams for the plant were characterized to determine the likely constituents of any solid waste. A summary of this characterization is presented in the table below.

CHOKECHERRY COAL TO METHANOL PLANT
SUMMARY OF PRINCIPAL WASTE STREAMS

	WASTE STREAM		
Process Step	To Air	Liquid	Solid
Coal Storage	-	Runoff and leachates	-
Coal Preparation	Particulates	-	-
Coal Drying	Flue gas and particulates	-	-
Gasification	Vent gas, fugitive emissions	Quench water	Slag and ash
Gas Cleaning	-	Quench Water	Fly ash and filter cake
CO shift	-	-	Spent catalyst

Process Step	WASTE STREAM To Air	Liquid	Solid
Acid Gas Removal	-	Solvent blowdown	-
Sulfur Recovery	Tail gas	Purge	Sulfur
Methanol Synthesis	-	-	Spent catalyst
Cooling Tower	Drift	Blowdown	-
Auxiliary Boiler	Flue gas and particulates	Metal cleaning waste	Ash
Wastewater Treatment	-	Treated wastewater	Sludges
Solar Pond	-	-	Residual Sludge

The impact of air emissions from the plant has been discussed earlier in this chapter. Liquid wastes are treated in the wastewater treatment facility, and are ultimately either disposed in the solar evaporation pond or appear as a sludge for disposal as solid waste. The characteristics of the solar evaporation pond were also discussed above. Therefore, the balance of this section concentrates on the properties of the solid waste from the plant, and on our conclusions on disposal requirements.

Properties of Solid Waste

Hazardous waste, as defined in RCRA, requires more comprehensive and expensive disposal procedures than non-hazardous wastes. Thus, it is important to assess the likelihood that any solid waste produced in the plant will be hazardous.

The chief factors that give rise to a potential for hazardous waste are the feedstock itself and the combustion reactions that take place in the gasifier. These factors are interrelated, because possible volatilization of trace elements may take place in the gasifier. Unvolatilized trace elements will carry over into liquid or solid waste streams. To establish the degree of volatilization, and thus to estimate accurately the trace element concentration in the liquid or solid waste streams, requires a gasification test using coal that will be the feedstock to the plant. This gasification test, as well as combustion tests to produce samples of boiler ash, also provide the slag and ash material necessary to measure the leaching properties of these solid wastes.

Because no gasification or ash tests were conducted during Stage III, no quantitative estimate of potential hazardous material in the solid waste itself can be made. However, available data on the coal feedstock and on the gasification reaction as reported in the Espey-Huston report indicate the following:

1. Analysis of the coal proposed as feedstock for the initial module shows that trace elements are typically at the lower limit of other western U.S. coals. Thus, it is not expected that trace element accumulations in the solid waste from the plant (principally in the combustion wastes) will create disposal problems more severe than those encountered by power plants that burn western coal.

2. The KBW gasifier operates at a high temperature, and is less likely than other gasifiers to produce tars, phenols, and other potentially hazardous combustion products. The material balances provided by KBW (see Appendix A) indicate that the principal contaminants in the raw gas from the gasifier that could appear as hazardous material in either liquid or solid form are: hydrogen sulfide (0.16 dry volume percent), COS (0.02%), sulfur dioxide (0.002%), cyanide (0.03%), and ammonia (0.05%).

In addition, a search of available literature by Espey-Huston, and proprietary KBW experience (including gasification, ash, and leachate tests) on other coal feedstocks were also used to assist in determining the possibility of hazardous waste generation.

These data appear to be sufficient to reach preliminary conclusions on the potential for the production of hazardous wastes, as reflected below.

Conclusions on Solid Waste Disposal

On the basis of the estimates of the properties of solid waste as outlined above, we have reached the following conclusions regarding the likelihood of generating hazardous solid waste and the associated disposal issues.

Coal Combustion Wastes

These wastes include slag, bottom ash, wet fly ash, and filter cake from the gasifier, raw gas cleanup, and auxiliary boiler. Gasification and ashing tests, and leaching analyses of slag and ash will be required to establish whether these wastes are hazardous. If leaching analyses indicate the presence of hazardous waste, it will most likely be because one or more trace elements from the feedstock appear in a leachable form in the slag or ash. Because of the relatively low trace element concentration in the coal, these wastes are probably not hazardous.

If the coal combustion wastes prove hazardous, however, they are treated under RCRA in a special category. Such wastes are not considered hazardous even though some portion of the waste might normally be so considered because: (1) the wastes are produced in large volume; (2) hazardous materials, while present, nonetheless present relatively low risks to the environment; and (3) the waste is not amenable to usual disposal techniques. EPA is studying this special waste category, and may revise the rules governing it within the next year. If the category is not revised, coal combustion wastes from the plant would be subject to less stringent disposal requirements than hazardous wastes. The disposal method would be the same as that for the disposal of solid wastes from electric power plants.

Even if EPA revises its rules and considers coal combustion waste, the coal combustion waste from this plant could be stabilized by conventional methods to reduce leaching below hazardous levels. Thus, the waste could be disposed of as a nonhazardous material.

In summary, although the exact requirements for handling coal combustion waste are not yet definite, it appears that this waste would not be disposed as a hazardous waste in any case because: (1) it is nonhazardous as produced; (2) it is subject to less stringent disposal requirements because of its special nature; and/or (3) it can be rendered nonhazardous prior to disposal.

Wastewater Treatment Sludge. Espey-Huston concludes that sludge from the wastewater treatment plant is likely to be nonhazardous, although quantitative estimates of the properties of these sludges will be required after gasification testing. If a hazardous constituent should be present, it would probably be caused by leaching of trace elements from the feedstock that have appeared in the sludge. Like coal combustion wastes, these sludges can be stabilized to reduce leaching and render them nonhazardous. For these reasons, we consider it unlikely that wastewater treatment sludges would be subject to hazardous waste disposal requirements.

Spent Catalysts

Spent catalysts will be hazardous wastes. However, catalysts will be removed only once every two or three years for disposal. Depending on the economics of catalyst regeneration, the spent catalyst may be returned to the manufacturer. If not, it must be sent to an approved disposal site. Because the catalysts are removed infrequently, the cost of their disposal even as hazardous waste would not be great.

Sulfur

Sulfur will be sold as a by-product and not disposed of as a waste.

Evaporation Pond Biosludge

Espey-Huston believes these wastes probably will be hazardous. Since any hazardous material in the sludge created after evaporation of supernatent liquids would have been present in the original wastewater discharge to the pond, the pond must be lined to prevent leaching of hazardous materials while in the liquid phase. This lining, together with stabilization of the sludge and filling of the pond upon decommissioning, should be adequate for ultimate disposal. Because the pond is used for wastewater discharges, it will initially be permitted under the NPDES system.

ECOLOGY

Ecological studies of the site and the surrounding area were separately conducted for aquatic biology, wildlife, and vegetation. Each is summarized below.

Aquatic Biology

The plant site lies between two small streams, Morgan Gulch and Collom Gulch. Below the site, these two streams merge and flow as Morgan Gulch to the Yampa River, some 10 kilometers to the north. Because the plant will be designed as a no discharge facility, no discharge of wastewater into either of these streams is anticipated. The hydrology report at Appendix F presents a full description of stream flow and water quality for Morgan Gulch and Collum Gulch.

Grace requested Western Resources Development Corporation to undertake an aquatic biology study of Morgan Gulch, since any drainage from the plant would be to the Morgan Gulch. Collum Gulch is an intermittent stream unlikely to support aquatic species. The Western Resources Development Corporation report is attached as Appendix I.

In conducting its study, the consultant examined the physiochemical characteristics of the stream (temperature, conductivity, pH, and turbidity), and sampled for aquatic macroinvertebrates and fish. Where possible, each of these analyses were performed on each of five stream segments, starting approximately 3 kilometers upstream of the plant site and extending to the confluence with the Yampa River. The principal findings of these analyses were as follows:

- Stream Section 1 was the southernmost 0.8 to 1.6 kilometers of the stream. This section of the stream contained flowing water. A substantial diversity of macroinvertebrates were found, but no fish were observed.
- The next 8.0 to 8.8 kilometers of Morgan Gulch did not contain flowing water, but did contain several pools. No fish were observed in these pools, but the consultant believes that macroinvertebrates were present.
- Section 3 comprised the next 2.4 kilometers of the stream, and contained one major pool with the balance being an ephemeral stream. Fish were found in the pools, but the consultant believes that macroinvertebrates were not likely to be found. The fish were common species, and included no threatened or endangered species.

- Section 4 was the last 0.8 kilometers of Morgan Gulch above the backwater of the Yampa River. Again, some permanent pools were found which are probably occasionally connected by flowing water. Macroinvertebrates are not likely to be found, but common species of fish were present in the pools.

- The final section studied was the backwater of the Yampa River, extending perhaps 100 meters into the mouth of Morgan Gulch. Although not found at the time of the study, it is possible that fish present in the Yampa River, including the Colorado squawfish, would from time to time be present in this backwater. It is, however, a resting and staging area rather than a spawning area for fish found in the Yampa River.

Based on the studies by Western Resources Development Corporation, Grace believes that there is no reason to believe that there will be any adverse effect on aquatic species as a result of plant construction. Because the plant will not discharge wastewater through Morgan Gulch, there will be no adverse effect from this source either in Morgan Gulch or in the Yampa River. Although fish and macroinvertebrate populations are found in various sections of Morgan Gulch, the species present are common.

The Colorado squawfish is the only threatened or endangered species likely to be present in any part of Morgan Gulch. Since there appears to be little communication between the various segments of Morgan Gulch, it is highly unlikely that the Colorado squawfish or any other fish species present in the Yampa River would be found beyond the Yampa River backwater at the mouth of Morgan Gulch.

Wildlife

Grace commissioned a study of terrestial wildlife in the vicinity of the proposed plant early in 1981, and the study will be continued until early 1982. The study included both literature reviews and field surveys, which were conducted in January, April, June, July, and August 1981. The study approach was essentially qualitative, as opposed to the quantitative approach appropriate for surface mining where rehabilitation of disturbed land is of paramount importance.

This qualitative approach was approved by the Colorado Division of Wildlife. The report of the study is attached in Appendix J.

The Axial Basin is a significant wildlife area. Virtually the entire area is classified as a critical winter range for deer, and it also provides excellent habitat for antelope and elk. Numerous carnivores, small mammals, and rodents are present in the area. The project is within the general location of a Sage Grouse breeding area. Threatened and endangered species are actually or potentially present in the general area, including the Peregrine Falcon, Bald Eagle, Greater Sandhill Crane, Whooping Crane, and Black-footed Ferret. However, the immediate vicinity of the plant site is not a preferred habitat or hunting ground for these species.

Western Resources Development Corporation believes that the effect of habitat loss directly resulting from conversion of the plant site to an industrial facility will be minimal, except for the possibility of disturbing the Morgan Gulch #3 Sage Grouse strutting ground. More significant could be direct animal mortality and disturbance of habitat resulting from plant construction. Direct mortality could result from higher road kills, electrocution on power poles, or the use of firearms. The presence of construction workers and equipment could induce large animals to avoid rangeland in a zone 1.5 kilometers wide surrounding the plant site, and possibly along major access roads. This zone of habitat disturbance lies in possible winter feeding grounds for these mammals.

On balance, the wildlife impacts associated with the proposed plant will be no greater than those associated with coal mining activities in the area. The impacts created by the proposed plant involve the long term removal of a relatively small area from use by wildlife. In contrast, coal mining in the area involves the relatively short term denial of habitat over a much larger area.

Grace believes that the impacts of habitat disturbance and direct mortality can be adequately mitigated, insofar as they are presently known. Western Resources Development Corporation has recommended initial mitigation measures to minimize the possible impacts that have already been identified, including the use of bus transportation to the site, posting of speed limits, prohibition of firearms, reduction of the electrocution hazard, and enhancement of surrounding habitats to compensate for the area taken up by plant construction. These recommendations will be analyzed as specific construction plans are developed, and implemented as required. In addition, the feasibility of moving the affected Sage Grouse strutting ground will be investigated.

Vegetation

Western Resources Development Corporation described the vegetation types within a 50 mile radius of the plant, characterizing in more detail the vegetation within a four mile radius and on the plant site itself. This survey was used to determine if any threatened and endangered species would be affected by the plant, and to assess the impacts of air emissions on vegetation. The consultant's report is attached as Appendix K.

The results of this analysis indicated no significant impact of the plant on local vegetation. The project site, as well as the four mile area surrounding it, does not contain any threatened or endangered vegetation species contained on any proposed or legally recognized Federal or state list. Air emission concentrations appear to be well below levels that would affect the most sensitive plants in the area. Approximately 40 acres of rangeland vegetation would be eliminated by the plant, but this is an area that would produce forage for only one animal per year.

SOILS

Grace retained James P. Walsh & Associates, Inc. to inventory soils and land use in the project area, and to assess the impact of plant construction and operation. Relatively minor impacts from plant construction were expected, when compared with the substantial coal mining operations in the vicinity. Consequently, special attention was given to the likely impact of air emissions from the plant on soils. The Walsh report is attached as Appendix L.

Data on land use and soils were generated largely from available literature and from the professional experience of the consultant, with limited field surveys being employed. Site specific samples were taken to assist in assessing the impact of air emissions on soils.

Grace has arrived at the following conclusions regarding impacts on soils and land use:

1. The engineering properties of the soils at the plant site are adequate. Most of the soils have deep underground water tables and present no flood hazard. A few acres in the northwest corner of the site lies in the Morgan Gulch drainage, and have high water tables and are prone to flooding. This small area can be entirely avoided during construction.

2. While soils in the area have a fairly high potential for dust production during construction, overall soils impacts are limited. Adequate topsoil is available for salvage and for subsequent reconstruction and landscaping of the site to mitigate impacts.

3. The site is suitable for cultivation and as rangeland, and construction of the plant will remove the site area from these uses for at least the life of the project. Except for minor effects from access roads and utility corridors, land uses outside the site boundaries will be unaffected.

Air emissions impacts on soils are expected to be low. Sulfur oxide, nitrogen oxide, and hydrogen sulfide emissions could acidify rain falling in the area. Even if this effect should occur, little if any impact is likely to result. Eight of nine soil types in the vicinity meet EPA criteria as nonsensitive or practically nonsensitive to acidification. The ninth, while not meeting the criteria, appears north to northwest of the plant where the incidence of air emissions is low.

Other potential air emissions impacts are negligible. Any direct deposition of sulfur or nitrogen on the soils would slightly augment amounts of these elements already present. Particulate deposition is consistent with the dusty character of the natural soil. Trace element deposition would be small compared to existing coal-fired power plants.

CULTURAL RESOURCES

Grace retained Western Cultural Resource Mangement, Inc. to conduct an archeological survey of the site selected for the coal-sourced methanol plant. A copy of the consultant's report is attached as Appendix M.

Western Cultural Resource Management conducted a field survey of the site at a 100% level of coverage. In addition, searches of the files of the Office of the State Archeologist and of the Craig District Office of the Bureau of Land Management were conducted. The file search revealed no previous surveys or recorded archeological sites within the project site. The site investigation and the consultant's report were prepared in compliance with the National Historical Preservation Act of 1966 and the National Environmental Policy Act of 1969, and meet all requirements of Executive Order 11593 of 1971.

The survey located only one significant archeological site within the survey boundaries, consisting of three graves surrounded by a sheep wire fence. The consultant believes that these are graves of children, probably from an early farming family no longer resident in the area. On the basis of available information, the grave sites are not considered eligible for the National Register of Historic Places.

Western Cultural Resources Management recommends that the grave sites be avoided during plant construction by creating a 50 foot buffer zone around it. If that is not possible, the graves could be moved.

No other findings of archeological significance were located on the plant site, and Grace believes that there are no impediments to plant construction arising from archeological concerns.

CHAPTER X SOCIOECONOMIC IMPACT

Construction of the initial methanol production module and of subsequent expansion stages will create the need for additional construction, operating, and mining employment in northwest Colorado. These additional employees, the employment that they induce in local service industries, and their families will require housing, place new demands on services provided by local governments, and have other impacts on the existing social and economic conditions of the area. Of course, the plant and its associated employment will also increase the tax base and revenues of the local government jurisdictions.

Grace retained Resource Planning Associates (RPA) to examine the scope and nature of the socioeconomic impacts of land construction and operation. The RPA report is attached as Appendix N, and provides a detailed estimate of impacts for a variety of conditions. This chapter summarizes Grace's assessment of the socioeconomic impact of plant construction and operation, based both on the RPA report and on discussions with local government officials. Grace's overall conclusions are presented first, then the study approach and results of the RPA study are summarized.

CONCLUSIONS

Grace believes that the socioeconomic impacts of this project will be manageable. Specifically, Grace has concluded from its review that:

- Additional government services required to support the initial module will be relatively small, since only 400 construction workers (at peak) and 80 operating employees are involved. In Craig and Moffat County, existing and planned service levels will accommodate these additional requirements. In Meeker and Rio Blanco County, the impacts of the initial module represent less than 5% of the needs for additional services that are likely to occur owing to other energy developments in the area.

- Plant expansion will create the need for new services. However, these impacts will first appear after 1985, and will not reach their maximum until 1990 or later. Thus, adequate lead time should be available to plan for the orderly development of new services.

- Tax revenues from the initial module will begin in 1983, while the need for additional service connected to the initial module will not appear until 1985. Since the new service need is relatively small, it does not appear that a significant imbalance between revenues and service costs will occur during construction of the initial module.

- Revenue requirements for services connected with plant expansion will be larger, although no estimate of this need has been made. However, there is time to plan for these requirements, and it is anticipated that the ongoing revenue connected with the initial module will ameliorate any fiscal imbalances.

Although these conclusions present a relatively optimistic picture, Grace recognizes that there will be impacts on the social and economic patterns of areas affected by the plant. Cost-effective mitigation of the impacts will require close cooperation between the project and local authorities to take full advantage of the planning leadtimes available to them.

STUDY APPROACH

The methodology used in the socioeconomic study is discussed in detail in the RPA report. RPA employed a conventional approach for this type of analysis. Employment, both direct and indirect, was first estimated. The population growth associated with this employment was calculated for the period 1983 to 1993. Using standard factors to relate population to the need for public services, the incremental service requirements arising from plant construction and operation were developed. This procedure was reviewed with local officials to identify any corrections that should be made to reflect conditions in the area.

Grace believes this methodology presents a reasonable estimate of socioeconomic impact. As important, however, is to ensure that the assumptions used in the analysis are appropriate in light of the conditions existing in northwest Colorado. Considerable attention was given to developing the necessary assumptions, and the most important of them are reviewed below.

Construction Schedule. Although the construction schedule for the initial plant can be projected with reasonable accuracy, the schedule for plant expansion depends on the rate of market development. For purposes of this study, a baseline schedule was developed on the assumption that an orderly expansion could take place to minimize construction costs. This schedule projected that the initial plant construction would be completed in mid-1985. A 12 month operating period would follow to gain experience and to gather data to support permitting of the plant expansion. Two expansion stages would follow, ending in mid-1989 and mid-1992, respectively.

Two alternative schedules were considered. A compressed schedule, resulting in full plant expansion by 1990, would be followed if the market developed rapidly. An expanded schedule, reflecting slower market development, would end construction in mid-1993. The socioeconomic impacts of all three schedules are roughly the same, however, and so the baseline schedule was used for the detailed analysis.

Employment. The direct employment required by plant construction and operation is the driving force in analyzing socioeconomic impact. Using estimates supplied by KBW, peak construction employment is expected to be 400 persons for the initial plant, and 1000 persons for each of the expansion stages. Operating employment would rise from 80 for the initial module to 340 for the full scale plant.

Production of coal required for the plant will require additional mining employment, and this factor was included in the RPA analysis. Because of the relatively small feedstock requirements for the initial module, it was assumed that coal would be available from mines already operating in the area. As a result, no incremental mining employment was included for the initial module. However, the full scale plant would probably require the opening of new mines, which could add approximately 550 mining employees in the area.

Other Developments. Because of the potential for extensive energy-related developments in northwest Colorado, the requirements for public services could rise significantly in the area without construction of this project. If these other developments should occur, the employment required for the coal-to-methanol plant would add to the need for expanded public services that would take place in any case. On the other hand, if these other developments do not occur, the impacts of this project would be met in some cases by existing and already planned services.

Although it is impossible to predict exactly the path of energy development in northwest Colorado, it was decided to assess the potential impacts of this project by examining two limiting cases. One case assumed that no additional development took place, and this projection forecasts a natural population increase in the area on the order of 20% between 1983 and 1993. The other case assumed extensive energy development, resulting in a population increase of 100% or more during this period. Both cases used estimates prepared by the regional Council of Governments (COG) and are referred to in the balance of this report as the COG I and COG II projections, respectively.

Local Labor Availability. Socioeconomic impact also depends on whether the employment requirements of the plant can be met by locally available labor. If so, the influx of new population and the associated impact would be reduced. If labor must be imported, the full incremental impact could be felt.

During the construction of the initial module, local labor availability may be high. Construction of the third unit of the Colorado Ute power plant could be ending as construction of the initial module begins, and this labor force can be transferred from one project to the other. However, it seems probable that other energy developments in the area will create a scarcity of local labor during the plant expansion stages following 1985. To assess the impact of local labor availability, RPA analyzed cases for both high and low availability.

DISCUSSION OF RESULTS

The complete results of the socioeconomic study are contained in the RPA report. In this section, Grace presents its assessment of these results. The discussion is organized as follows:

- The impacts on Craig and Moffat County, and on Meeker and Rio Blanco County, are discussed separately. Because less than 1% of the employment is likely to settle in Hayden and Routt County, these impacts are minimal and are not discussed.

- Within each area, the impacts on services provided by city and county governments are discussed for both the initial module and subsequent expansions. These impacts are assessed using two criteria. One is the effect on the leadtime available to plan for the provision of additional services. The other is the magnitude of the incremental services required by this project.

- Finally, impact on housing, traffic, and financing are reviewed.

Craig and Moffat County

Services provided by Craig and Moffat County area, with one exception, adequate for their current citizens. Moreover, service expansions are already planned that will provide adequate services through 1985 even under the COG II population growth. The exception to this conclusion is the availability of recreational areas, which is already below desired levels. In general, however, Craig and Moffat County are positioned to provide services for orderly growth.

Against this background, the impacts of the initial module are likely to be small. Under the COG I Projection, it appears that no service capacities (except recreation) will be exceeded. If COG II growth occurs, additional police officers and school capacity will be required in 1985 or 1986, when construction of the initial module ends. However, this project does not accelerate the time at which capacity would be exceeded, and additional capacity required by the project is less than 5% of the total requirement in every case.

Plant expansion stages are likely to require additional government services. Using the COG II/low labor availability case, the following table summarizes the resulting impacts.

SUMMARY OF IMPACTS
ASSOCIATED WITH PLANT EXPANSION
CRAIG AND MOFFAT COUNTY

Public Service Impacted	Number of Years of Planning Leadtime Reduced	Earliest Year Of Maximum Impact	Maximum Incremental Capacity Required*
Water Supply	2 (to 1987)	1991	20%
Sewer System	3 (to 1990)	1991	11%
Police Force	0 (to 1985)	1991	26%
Police Vehicles	1 (to 1987)	1991	25%
Fire Pumping	0 (to 1987)	1991	12%
High Schools	0 (to 1986	1991	14%
Elementary and Middle Schools	1 (to 1985)	1991	14%
Hospital Beds	0 (to 1987)	1991	13%
Recreation	0 (to 1983)	1991	15%

*- As percent of maximum capacity required if plant were not built

If they occur, these impacts will have to be mitigated by providing additional services. However, it appears possible to plan for mitigation in an orderly way. As shown in the above table, plant expansion does not seriously affect planning lead time, and in no case does the impact occur before 1985. And, while maximum additions to capacity range from 12-26%, this peak level does not occur until 1991.

Moffat and Rio Blanco County

Services in Moffat and Rio Blanco County must be expanded to support any significant energy-related development. For example, under the COG II growth projection, the capacity of all government services will be exceeded in 1983 or 1984. Thus, construction of this project will not accelerate the need to begin expanding government services, but will add requirements for capacity as these services are expanded.

In this situation, the effects of the initial module are difficult to distinguish from the service expansions that may be required in any case. If COG II growth occurs, all services will have to be expanded well before peak construction is reached on this project. Even in the case of COG I growth, additional fire and recreational services will be needed in 1983, whether or not this project is constructed. Thus, the effect of the initial module is to increase capacity requirements that must be expanded in 1983 in any case. The additional capacity requirement ranges between 1 and 5% of the capacity that would be needed without plant construction.

In the case of plant expansion, incremental impacts reach their maximum between 1991 and 1993. While these impacts will require mitigation, they represent a relatively small part of the total service expansion that will be required. For example, under COG II projection, services in Meeker and Rio Blanco County will have to increase in the range of 85 to over 300% without construction of this project.

Other Factors

In addition to the services provided by local governments, impacts will be felt in areas not directly funded by these jurisdictions. These impacts include housing and traffic.

It appears that housing for the labor connected with initial plant can be accommodated with housing units already planned for development. Plant expansion will create additional demands, but, as with government services, the impact does not become significant until after 1985. This should provide adequate lead time for orderly development of new housing units.

Vehicle registrations in the area will increase in proportion to the population. Traffic induced by increases in vehicle registrations may not increase proportionately, however. Many new residents will live in outlying suburbs, thus diffusing potential congestion. Also, employment-related travel can be reduced by techniques such as van pools.

Nonetheless, these impacts will require mitigation, and Grace believes that this project can effectively share in the necessary actions.

Finally, revenues must be available to pay for the additional services required by plant construction. Grace did not request RPA to prepare a detailed financial analysis, pending review and discussion of the impact estimates themselves. However, a preliminary analysis of financial requirements is encouraging.

p

In general, new services required by the initial module are relatively small, and, if they occur, take place in 1985 or 1986. Since the tax base and employment in the area begins to grow in 1983, new revenues will be generated before 1985. Preliminary analysis indicates that the cumulative tax revenues by 1985 could amount to several hundred thousand dollars in Craig and Moffat County, and to approximately $100,000 in Meeker. Because these revenues will tend to be available before services must be put in place, Grace does not anticipate an imbalance between funding requirements and revenue availability for the initial module.

Grace also recognizes that the financial requirements for plant expansion, and the associated revenue estimates, will require further refinement. However, the ongoing operation of the initial plant will tend to ameliorate any financial requirement imposed by the impact of subsequent expansion.

The preceding chapters outlined the basis for Grace's conclusion that both the initial module and subsequent expansion stages of the coal-sourced methanol plant will comply with known environmental requirements. This chapter discusses the regulatory permitting process itself.

CONCLUSIONS

The principal objectives of our analysis of the regulatory process were to identify the permits required for plant construction and to gain agreement on a schedule for submitting and deciding on the required permits. Grace believes these objectives have been achieved, and that a permit schedule has been developed that maintains the fast-truck design and construction schedule for the initial module. In particular:

- Although 30 permits will be required prior to construction and/or operation of the plant and its associated loadout facility, only four are critical to the overall schedule. These are the Prevention of Significant Deterioration (PSD) permit, the State Air Emissions Permit, the National Pollution Discharge Elimination System (NPDES) no-discharge permit, and the county Conditional Use Permit (CUP).

- Through the Colorado Joint Review Process (CJRP), the agencies responsible for processing these critical-path permits have agreed to a schedule satisfactory to Grace. To maintain the schedule, applications for the PSD, State Air Emissions, and NPDES permits should be filed by mid-July, 1982. The county CUP application must be made no later than mid-September, 1982, but agreement on socioeconomic impact and any mitigation measures should precede the application. All other permits required prior to construction will require no more than 4 months to process.

- Since no major federal action is required for plant construction (within the meaning of the National Environmental Policy Act) a formal Environmental Impact Statement should not be required. However, it is Grace's policy to make a complete study of the environmental impacts of the plant, and to make this information available to the public and appropriate regulatory agencies for comment.

As noted in earlier chapters, Grace has analyzed the environmental impact of the large plant to ensure that it will meet regulatory requirements. Although the regulatory analysis during the Stage III study concentrated on the permit schedule for the initial module, Grace believes that the large plant can receive the necessary permits on a reasonable schedule as well. Adequate time should be available to prepare an Environmental Impact Statement for the large plant, if one is required, and to prepare and secure approval of the necessary permit applications. Moreover, data obtained from the operation of the initial module will provide a firm basis for preparing permit applications for the expansion stages, thus reducing any uncertainty in determining whether the large plant will comply with environmental requirements. Finally, Grace will apply at the outset for a phased-construction PSD permit, which would both allow construction of the initial module and reserve the air quality increment necessary for future expansions.

APPROACH TO THE REGULATORY ANALYSIS

Grace retained Resource Planning Associates (RPA) to assist in identifying permit requirements and schedules. In its role as project manager, ETCO assisted Grace in reviewing the permit requirements with the appropriate regulatory agencies, in integrating the permitting schedule with the overall plant design and construction schedule, and in developing a formal Project Decision Schedule. The RPA report is attached as Appendix O, and contains most of the factual information on permit requirements that has been collected for this study.

However, Grace and ETCO have conducted extensive discussions with regulatory agencies following submission of the RPA report, and the RPA report should be viewed as input for these discussions rather than as a record of their conclusions. This chapter will summarize the final results of the regulatory analysis.

The permit directory developed by the State of Colorado, discussion with all principal regulatory agencies, and other sources were used to identify the permits required for the project. However, the chief vehicle for working out the regulatory requirements and schedules was the Colorado Joint Review Process (CJRP).

The CJRP is a mechanism developed by the State to coordinate the work of project sponsors with the federal, state, and local agencies that have regulatory authority over a project. The CJRP process has three major phases. Phase I involves the development of an agreement between the project sponsor and the Colorado Department of Natural Resources that the project will be part of the CJRP; Grace applied for entry to the CJRP on December 5, 1980, and was accepted on December 22, 1980. Phase II of the CJRP is devoted to identifying regulatory issues and permit requirements, and concludes with agreement on a Project Decision Schedule (PDS). The PDS documents the actions required of the project sponsor and the regulatory agencies to ensure that key permits are processed promptly and on a schedule that is compatible with the overall project schedule. Grace has now secured an acceptable PDS, and has therefore concluded Phase II of the CJRP. The final phase of the CJRP is the permit application and approval process itself, which is constantly monitored to maintain the schedule developed in the PDS.

The CJRP has numerous advantages, especially when applied to a project in a relatively early stage of development. The process enables project sponsors to work expeditiously and simultaneously with all the involved regulatory agencies, increasing the confidence that an important permit issue is not overlooked. The PDS helps to ensure that the permit schedule is compatible with the project schedule, and that duplicative application information is minimized. Perhaps of greatest importance to a relatively novel project such as this one, however, is the opportunity afforded through the CJRP to review the project with the public. Grace believes that public participation both reduces the potential for suspicion and misinformation that sometimes accompanies announcement of a major energy project, and also provides for the identification of issues of public concern early in the process, when they can most easily be resolved.

In the course of the work on Stage III, four CJRP public meetings were held:

- <u>February 2, Denver</u>. All agencies involved in the CJRP program were briefed on the project.

- <u>March 5, Craig</u>. A public meeting was held to describe the project, the approach to the Stage III study, and the objectives of the CJRP. A preliminary list of required permits was distributed for comment.

- April 7, Craig. A public meeting was held to present Grace's analysis of permit requirements. This analysis was thereafter distributed to all CJRP agencies for comment. Although Grace is ultimately responsible for identifying all the necessary permits, this use of the CJRP provided a means for testing Grace's conclusions.

- June 4, Craig. This public meeting was preceeded by a tour of the four alternate sites that had been studied during Part I of the environmental analysis. Grace presented its site selection analysis at the meeting, and also presented its final list of required permits. A questionnaire was distributed by the Colorado Department of Natural Resources to identify any issues that the public wanted to raise. These issues were summarized by the Department of Natural Resources and analyzed by Grace to ensure that all the issues were being properly addressed. The summary of the questionnaire and responses is attached at Exhibit 8.

At the conclusion of the Stage III work, a public meeting is planned in Craig to wrap up Phase II of the CJRP. At this meeting, Grace will summarize the results of its environmental analysis, with particular reference to the issues identified in the June 4 meeting. The water supply system for the project will also be discussed and the final PDS will be presented. Following this meeting, Grace will distribute the subcontractor reports on environmental impact through the CJRP to appropriate regulatory agencies for more detailed comment.

SUMMARY OF RESULTS

Exhibit 9 lists the 30 permits that were identified as being required for the initial plant and its associated loadout facility. The RPA report tabulates the detailed requirements of each of these permits, as well as for other permits that were determined not to be required.

The bulk of these required permits are not complex and can be obtained in four months or less. Exhibit 10 shows the anticipated schedule for obtaining the permits required for the plant itself. Four permits are on the critical path, and they are briefly discussed below.

- PSD/State Air Emissions Permit. The PSD permit (which is processed concurrently with the State Air Quality Permit) will be requested on a phased-construction basis. The effect of a phased-construction permit is to secure PSD approval for the initial module while simultaneously establishing that the full scale plant will also meet all air quality requirements. On this basis, the air quality increment necessary to construct the full scale plant will be reserved for the project, provided that the project adheres to an agreed construction schedule. Expansion stages must be rejustified, with a separate PSD permit obtained prior to construction to ensure that the basis for approving the original phased-construction permit remains valid. To maintain the PSD schedule for the initial plant, it will be necessary to secure permit approval before complete air quality baseline data have been collected. This matter has been discussed with both the Environmental Protection Agency and the Colorado Department of Health, and it appears feasible to proceed on this basis, for the reasons discussed in the Air Quality section of Chapter 9.

- NPDES. Although the NPDES no-discharge permit is required only before plant operation, Grace has assumed that it should be secured prior to construction. The plant is designed to discharge no wastewater, but it is prudent to verify prior to plant construction that the necessary no-discharge permit can be obtained.

- CUP. This permit will be considered by Moffat County, and is designed to assure local authorities that the project has complied with all environmental requirements, and that all necessary socioeconomic mitigation programs have been developed, prior to plant construction. Based on our discussion with the County, all the necessary review and agreements can be in place prior to issuance of the PSD and NPDES permits. Thus, final CUP approval can be made promptly upon approval of these critical path permits. As shown on Exhibit 10, all other permits can be approved prior to issuance of the PSD and NPDES permits.

Exhibit 11 lists the permits that could be required for the plant, but for which insufficient information is available to make a determination at this point. While some of these permits may be necessary, it does not appear that any is likely to cause a project delay. Specifically:

- Hazardous Waste Permit. Although the project may generate a hazardous waste (see Chapter 9), no permit is required unless the project itself treats, stores, or disposes of such waste. (A generator of a hazardous waste need only provide notification and comply with certain packaging, labelling, and documentation requirements, for which a permit is not required). If coal or water treatment wastes prove hazardous, the project may treat these wastes by stablizing them so they can be disposed as a non-hazardous waste. Such treatment is conventional, and ample time is available to secure the necessary permit, since the permit is not required until initiation of operation. Hazardous wastes, if any, will be shipped to disposal sites operated by others.

- Migratory Bird Permit. This permit will be required if raptor nest or Sage Grouse strutting grounds have been relocated. The final plant site deliberately selected to minimize this possibility.

- Section 7 Consultation. This action would be triggered by a federal agency on the grounds that a threatened or endangered species would be adversely affected by the plant. The ecology study available to Grace indicates that this prospect is unlikely. However, the ecology report will be circulated through the CJRP for comment, and if any questions are raised, a Section 7 Consultation will be initiated immediately.

- Open Burning and Special Transportation Permits. These permits may be required during construction, but only one week is needed for their approval.

Finally, Exhibit 12 lists the permits that were identified but will not be required for this plant, and Exhibit 13 is the Project Decision Schedule developed for the project.

EXHIBITS

LITTLE BEAR CREEK COAL

The raw coal feed to the plant was assumed to be Little Bear Creek coal having the following analysis:

Proximate Analyses - Wt. %

	As Received	Dry Basis
Fixed Carbon	40.51	51.06
Volatile Matter	30.41	38.32
Ash	8.43	10.62
Moisture	20.65	0.00
	100.00	100.00

Ultimate Analysis - Wt. %

	As Received	Dry Basis
C	53.82	67.82
H	3.58	4.52
N	0.92	1.16
O	12.36	15.57
S	0.25	0.32
Ash	8.41	10.59
Cl	0.01	0.02
H_2O	20.65	0.00
Total	100.00	100.00

Coal size delivered to plant -- 2" x 0"
Hardgrove Grindability Index -- 55
Gross Heating Value -- 11,547 Btu/lb (Dry)

ASH FUSION CHARACTERISTICS ^0F

	Reducing	Oxidizing
I.D.	2,131	2,198
Fusion	2,164	2,215
Fluid	2,299	2,359

ASH ANALYSIS

Component	Wt. %
P_2O_5	0.00
SiO_2	50.09
Fe_2O_3	9.09
Al_2O_3	16.59
TiO_2	0.00
CaO	21.51
MgO	2.72
SO_3	0.00
K_2O	0.00
Na_2O	0.00
Total	100.00

SITE MAP

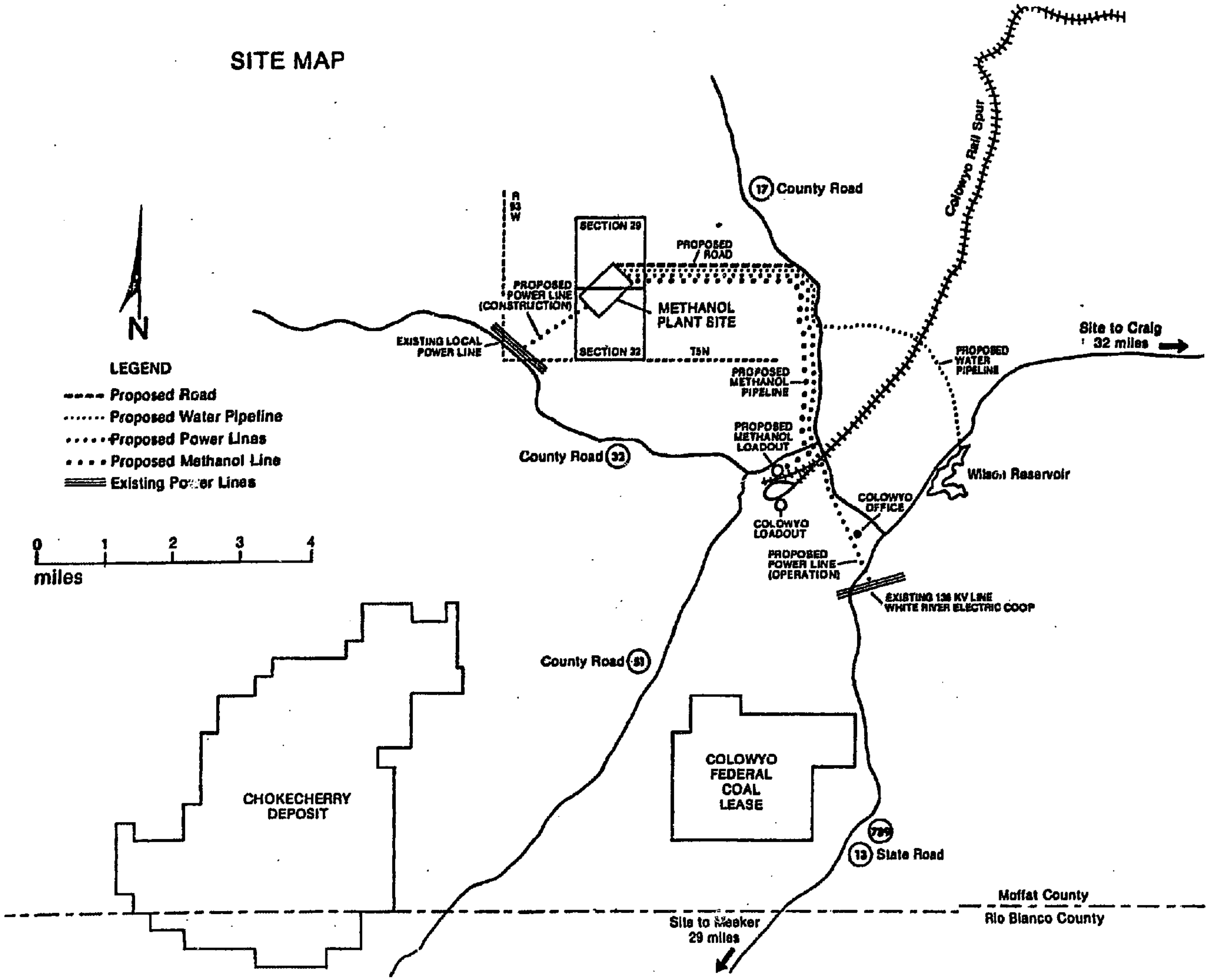

N
LEGEND
Proposed Road
Proposed Water Pipeline
Proposed Power Lines
Proposed Methanol Line
Existing Po er Lines
0 1 2 3 4
miles
R 93 W
SECTION 29
SECTION 32
T5N
PROPOSED ROAD
PROPOSED POWER LINE (CONSTRUCTION)
METHANOL PLANT SITE
EXISTING LOCAL POWER LINE
17 County Road
Colowyo Rail Spur
PROPOSED METHANOL PIPELINE
PROPOSED METHANOL LOADOUT
COLOWYO LOADOUT
PROPOSED POWER LINE (OPERATION)
COLOWYO OFFICE
PROPOSED WATER PIPELINE
Site to Craig 32 miles
Wilson Reservoir
EXISTING 138 KV LINE WHITE RIVER ELECTRIC COOP
County Road 32
County Road 51
CHOKECHERRY DEPOSIT
COLOWYO FEDERAL COAL LEASE
13 State Road
Moffat County
Rio Blanco County
Site to Meeker 29 miles

Exhibit 3

Estimated Growth in U.S. Methanol Markets - 1980-1990
(Millions of Gallons Per Year)

Methanol Uses	1980	1985	1990
Chemicals			
Formaldehyde	505	790	970
Solvent	120	140	170
Acetic Acid	85	140	190
Other Chemical Uses	255	320	380
Chemicals Subtotal	965	1,390	1,710
Fuels			
Fuel additives	90	330	530
Direct Gasoline Replacement			1,500
Utility	5	25	500
Fuel Subtotal	95	355	2,530
Miscellaneous	140	165	205
TOTAL MARKET	1,200	1,910	4,445
Chokecherry Production	-	537	537
% of Market	-	28%	12%

Source: Hinge Petro/Chem Service, Inc., for the U.S. National Alcohol Fuel Commission (1980)

Selected Refineries on the U. S. West Coast

Refiner/State	Crude Capacity Barrels per Stream Day
CALIFORNIA	
Atlantic Richfield Co. - Carson	186,000
Chevron U.S.A. Inc. - El Segundo	435,000
- Richmond	325,000
Exxon Co. U.S.A. - Benecia	107,000
Mobil Oil Corp. - Torrance	131,100
Pacific Refining Co. - Hercules	91,400
Shell Oil Co. - Martinez	94,000
- Wilmington	96,000
Tosco Corp. - Avon	132,600
Union Oil Corp. of CA - Wilmington	111,000
COLORADO	
Asamera Oil - Commerce City	44,900
Conoco - Commerce City	10,500
Gary Refining Co. - Fruita	14,000
KANSAS	
CRA, Inc. - Coffeyville	60,723
Getty Refining & Marketing Co. - El Dorado	82,000
Mobil Oil Corp. - Augusta	54,500
UTAH	
Amoco Oil Co. - Salt Lake City	41,500
Chevron U.S.A. - Salt Lake City	46,000
Husky Oil Co. - North Salt Lake	26,000
Phillips Petroleum Co. - Woods Cross	25,000
WYOMING	
Amoco Oil Co. - Casper	49,000
Husky Oil Co. - Cheyenne	30,000
Sinclair Oil Corp. - Sinclair	72,000
TOTAL	2,265,223

Source: Petroleum Refineries in the United States and U.S. Territories, January 1, 1980, DOE. Office of Oil and Gas Statistics, DOE/EIA - 0111(80).

Exhibit 5 E.7

12/21/81

W. R. GRACE & COMPANY
THE CHOKECHERRY PROJECT

EXHIBIT 5
CASH FLOW PROJECTION

ASSUMPTIONS: METHANOL PRODUCTION: 537 MILLION GALLONS/YEAR
METHANOL PRICE (NOVEMBER 1981): $ .75/GALLON
METHANOL PRICE (APRIL 1987): $ 1.14/GALLON (MID-OPERATING YR)
MARKET PRICE INFLATED FROM 1981 AT 8 PCT PER YEAR
PRODUCTION COSTS INFLATED FROM 1981 AT 8 PCT PER YEAR TO MID-OPERATING YR
COAL COSTS INFLATED FROM 1981 AT 8 PCT PER YEAR TO MID-OPERATING YR
START-UP SCHEDULE:
25 PCT CAPACITY IN FIRST YEAR
50 PCT CAPACITY IN SECOND YEAR
90 PCT - FULL PRODUCTION - FROM THIRD YEAR
FULL PRODUCTION COSTS ASSUMED EACH YEAR

($MILLIONS)

OPERATING YEAR	1	2	3	4	5	6	7	8	9	10	11	12
REVENUES	$ 169.1	$ 365.4	$ 713.5	$ 770.6	$ 832.2	$ 898.8	$ 970.7	$1048.3	$1132.2	$1222.8	$1320.6	$1426.3
LESS												
PRODUCTION COSTS	133.5	144.2	155.7	168.2	181.6	196.1	211.8	228.8	247.1	266.9	288.2	311.3
COAL COSTS	45.5	100.0	196.4	212.1	229.1	247.4	267.2	288.5	311.6	336.6	363.5	392.6
INTEREST	197.4	195.5	193.2	190.7	187.8	184.4	180.5	176.1	170.9	165.0	158.3	150.5
DEPRECIATION	257.1	405.9	305.3	204.8	104.5	4.1	3.6	3.5	3.5	3.5	3.5	3.5
CAP INT AMORT	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5		
PROFIT BEFORE TAX	(497.9)	(513.8)	(170.6)	(38.7)	95.8	233.2	274.1	317.9	365.6	417.4	507.1	568.4
TAX					44.1	107.3	126.1	146.3	168.2	192.0	233.3	261.5
PROFIT AFTER TAX	(497.9)	(513.8)	(170.6)	(38.7)	51.7	125.9	148.0	171.7	197.4	225.4	273.9	307.0
ADD												
DEPRECIATION	257.1	405.9	305.3	204.8	104.5	4.1	3.6	3.5	3.5	3.5	3.5	3.5
CAP INT AMORT	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5	33.5		
PROJECT GROSS CASH GAIN	$(207.3)	$ (74.3)	$ 168.2	$ 199.6	$ 189.7	$ 163.6	$ 185.1	$ 208.7	$ 234.4	$ 262.4	$ 277.3	$ 310.4
LESS												
LOAN RETIREMENT	12.8	14.7	17.0	19.5	22.4	25.8	29.7	34.1	39.3	45.2	51.9	59.7
PROJECT NET CASH GAIN	$(220.1)	$ (89.0)	$ 151.2	$ 180.1	$ 167.3	$ 137.8	$ 155.4	$ 174.6	$ 195.1	$ 217.2	$ 225.4	$ 250.7
ADD												
INVESTMENT TAX CREDIT	131.3											
OPERATING LOSS TAX SAVING	229.0	236.3	78.5	17.8								
TOTAL CASH GAIN	$ 140.3	$ 147.3	$ 229.7	$ 197.9	$ 167.3	$ 137.8	$ 155.4	$ 174.6	$ 195.1	$ 217.2	$ 225.4	$ 250.7
PERCENT RETURN ON EQUITY	24.9	26.1	40.7	35.1	29.7	24.4	27.6	31.0	34.6	38.5	40.0	44.5

EQUITY: $ 564 MILLION
10 YEAR CURRENT DOLLAR RATE OF RETURN ON EQUITY: 27.41 PERCENT
10 YEAR CONSTANT DOLLAR RETURN: 17.47 PERCENT

20 YEAR CURRENT DOLLAR RATE OF RETURN ON EQUITY: 31.28 PERCENT
20 YEAR CONSTANT DOLLAR RETURN: 21.55 PERCENT

Exhibit 6 E.8

ALTERNATE SITE MAP

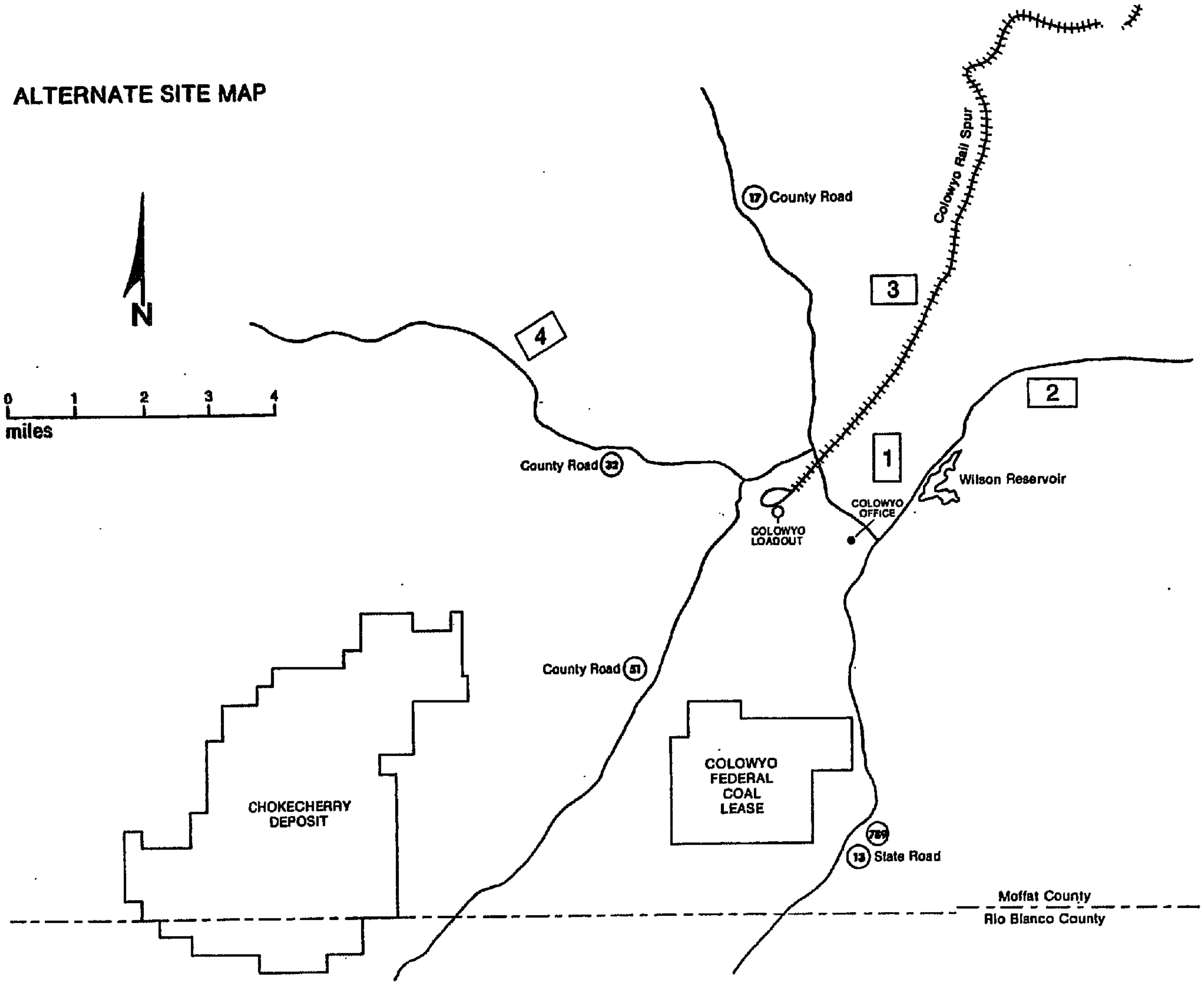


Exhibit 7

TABLE 3-1

W.R. GRACE CHOKECHERRY PROJECT

SITING CRITERIA MATRIX

Criteria	Sites 1	2	3	4
AIR				
Gaseous Emissions	5	2	1	2
Particulate Emissions (fugitive dust)	0**	2	4	3
Odor	4	3	3	4
Stack Flame	4	3	3	4
Steam Plume	5	3	2	4
Class I Areas	4	3	3	4
PSD	4	2	1	3
VISIBILITY				
Integral Vistas	2	3	2	4
Visibility Aesthetics	1	2	1	3
HYDROLOGY				
Floodplains	3	3	2	3
Sensitive Groundwater Aquifers	4	2	4	4
Proximity to Major Drainages	3	2	3	4
Existing Water Quality*	2	2	2	2
Potential for Adverse Impacts to Surface Water Quality	4	2	4	4

Rating System: 5 = Excellent, 4 = Good, 3 = Average, 2 = Fair, 1 = Poor, 0 = Fatal Flaw

* Quality of nearby surface water drainages compared to EPA Primary and Secondary drinking water standards.

** Indicates fatal flaw, eliminating site from consideration.

TABLE 3-1 (Continued)

Criteria	Sites 1	2	3	4
NOISE				
Receptor Impacts	4	4	4	4
CULTURAL RESOURCES				
State Register	5	5	5	5
National Register	5	5	5	5
Local Concerns	5	5	5	5
Potential (Unevaluated) NRHP Sites	4	5	2	4
SOCIOECONOMICS				
Community Reaction to Project	3	3	3	3
Work Force	3	3	3	3
Community Facilities	3	3	3	3
Existing Land Use	3	3	3	3
HAZARDOUS WASTE				
Hazardous By-Products Generated	3	3	3	3
Landfill Availability	1	1	1	1
Onsite Disposal	3	3	3	3
Offsite Disposal	4	3	5	2
Non-hazardous Waste Management Facility	4	4	4	4
SOILS				
Water Erosion Potential	4	3	3	3
Wind Erosion Potential	2	3	3	3
Land Use Sensitivity	5	3	2	2
Soil Mechanics	4	3	1	3

p

STATE OF COLORADO RICHARD D. LAMM, Governor

DEPARTMENT OF NATURAL RESOURCES

D. MONTE PASCOE, Executive Director
1313 Sherman St., Room 718, Denver, Colorado 80203 839-3311

Board of Land Commissioners
Division of Administration
Division of Mines
Division of Parks & Outdoor Recreation
Division of Water Resources
Division of Wildlife
Geological Survey
Oil and Gas Conservation Commission
Soil Conservation Board
Water Conservation Board
Mined Land Reclamation

E.11

Exhibit 8

M E M O R A N D U M

TO: JRP - W. R. Grace Team and Interested Parties

FROM: Steve Norris, Project Manager,
DNR-Colorado Joint Review Process SN

DATE: June 12, 1981

SUBJECT: Issues Raised During Consideration of the W. R. Grace Project, February 2, 1981 to June 4, 1981

Despite the absence of a formal "scoping" requirement during the review of W. R. Grace's proposed 500 TPD coal-to-methanol plant, the Joint Review Process Team has made an effort to encourage public involvement in the identification and discussion of issues. This memorandum summarizes the Team's effort and outlines the issues considered to date. At a later stage in the Joint Review, a more comprehensive scoping paper will be prepared to serve as a reference during consideration of possible plant expansion proposals.

No particularly crucial or controversial issues have yet emerged during review of the W. R. Grace Project. Site selection, socioeconomic impacts, including the cumulative impacts of several projects in the area, and water supply arrangements are the topics most often cited as needing considerable attention. W. R. Grace is fully aware of the importance of its efforts to study and report on these aspects of the project. The company has already reported on its preferred site and site selection process* and is now preparing a socioeconomic impact analysis and mitigation plan. It is also working to complete arrangements for providing an adequate water supply to the project and intends

---

*At the June 4 meeting, W. R. Grace presented the results of its site selection activities. Four alternative sites were evaluated in terms of forty criteria and the resulting comparison indicated a strong preference for site #4. A question was asked about why the various criteria were not weighted and notice was given that W. R. Grace and the Division of Wildlife needed to work closely together to mitigate the impacts of a plant located at site #4 on the sage grouse strutting grounds. Beyond these items, there was no apparent concern expressed over the site selection process or the preferred site.

to discuss these arrangements as soon as they are completed. Once these matters have been more fully examined by W. R. Grace, interested agencies and individuals will be better able to understand and evaluate the complete 500 TPD project.

There have been four general JRP - W. R. Grace meetings since the company's participation in the Joint Review Process was approved by the Governor in January, 1981. Each has had a somewhat different emphasis, but all were intended to familiarize agencies and individuals with the project and to solicit their active participation in discussion of plans, impacts and concerns. Very briefly, the four meetings included:

1. Interagency Meeting, February 2, 1981. Intended primarily to open the dialogue between regulatory agencies and the company, this Denver meeting was attended by more than 50 people.

2. JRP Team Meeting, March 5, 1981. About 75 people attended this meeting in Craig to introduce local residents and officials to the proposal.

3. JRP Team Meeting, April 7, 1981. Regulatory actions required by W. R. Grace were the focus of this meeting in Craig. About 40 people attended.

4. Public Information Meeting, June 4, 1981. Almost 60 people were present at this evening meeting in Craig to hear a comprehensive report on the project and to identify and discuss issues. This meeting was intended to be the major "scoping" activity to date and relied heavily on information exchanged at previous meetings. Written comment forms were used to supplement oral remarks.

During the course of these four meetings and numerous other meetings and discussions related to the Grace project, a number of issues have emerged. Most of them have received no more than passing notice from the public. The following outline identifies these issues:

1. Socioeconomic Impacts (primary and secondary)

   - housing
   - public finances
   - public facilities

- public services
- job/wage impacts
- health and safety
- schools
- local plans
- transportation
- recreation
- analysis and mitigation efforts by W. R. Grace

2. Water (quality and supply)

- treatment and discharge
- runoff
- salinity
- water rights
- storage and diversions
- impacts on other users
- water requirements

3. Air Quality

- PSD
- dust
- visibility
- secondary impacts
- nature of emissions
- impacts on air quality standards

4. Hazardous Materials
   - nature of materials
   - handling and storage
   - impacts on air, water and soils
   - methanol storage
5. Waste Disposal
   - nature of materials
   - handling
   - disposal sites
   - site management
   - reclamation
6. Ecology
   - wildlife and habitat
   - aquatic life and habitat
   - vegetation
   - rare/endangered species
   - wetlands/other sensitive areas
   - soils
7. Energy Requirements
   - energy source(s)
   - "net energy balance"
   - energy efficiency

8. Plant Closure/Reclamation

   - plant life
   - closure plans
   - reclamation plan

9. Cumulative Impacts (socioeconomic)

   - this project in conjunction with other coal and oil shale projects
   - participation in CITF* and/or other efforts

10. Cultural Resources

   - sites
   - procedures for protection

11. Methanol Markets and Means of Transportation

   - likely destination(s) of product
   - alternative transportation/delivery systems - sequence of use
   - market development expectations

12. Coal Source(s)

   - for initial phase <u>and</u> expanded plant
   - associated impacts, e.g., transportation, population growth

13. Other(s)

   - impacts on agriculture
   - geologic hazards/problems
   - plans for expansion; schedule
   - relationship to NEPA

* Cumulative Impact Task Force

- regulatory requirements for plant expansion
- plant shutdowns

A few issues have been asked about repeatedly or discussed in some detail. Briefly, these issues can be summarized as follows:

1. how much water does the plant require? how will this water be supplied? effects on agricultural water? use of reservoir(s)?

2. adequacy of housing? siting of new residential developments? commitment by W. R. Grace to rely on existing population centers to accommodate growth.

3. impacts of the project on traffic volumes and road maintenance costs, proposed mode of methanol transport; coal transport.

4. "cumulative impacts" relating to socioeconomic, air quality and water availability and quality.

5. employment opportunities

6. the nature and handling of hazardous and solid waste materials

7. possible sources of coal supply and associated impacts (especially if the the plant is expanded)

8. facility site selection and associated impacts

Although these issues relate explicitly to the initial 500 TPD module, interest has also been expressed in plans for plant expansion and the additional impacts likely to result.

At the June 4 Public Information Meeting, the JRP Team asked for written comments or issues, concerns and other aspects of the W. R. Grace project. Twelve people responded on the forms provided. Their comments are compiled below. First, is a listing by issue group of the comments made in response to the request for the "five most important issues". Second, are the remarks made regarding topics which deserve further attention. Only explicit comments are included. A copy of the response form is attached to this memorandum.

I. Five most important issues

A. Socioeconomics (including cumulative socioeconomic impacts)

1. Possibility of mass transit system to transport workers from Craig to site

2. Human services: mental health, social services, planned parenthood; what will be the impact on these and what is industry's responsibility?

3. Cumulative employment and economic impacts. The employment labor force analysis looks too simple. The needed expertise in appropriate work categories may be short within the local population.

4. How to deal with peaks and valleys in employment and population

5. Cumulative impacts on Craig facilities; considering ongoing and proposed actions, i.e., more coal mining, oil and gas, gold, and major pipeline construction.

6. Commuter traffic; roads

7. Recreational facilities

8. Housing

9. Community facilities

B. Water Quality and Supply

1. What conflicts, during drought years, will there be for water sources with both existing mines and future mines in the area?

2. Water supply and amount needed. Discharge. Rights.

3. What impacts will be caused by developing water sources? Availability?

C. Air Quality

1. Regional air quality impacts - cumulative, not just site specific (two comments)

D. Hazardous Materials

1. Heavy metals may be naturally associated with the coal. Has this been analyzed? What will be the effects of this in waste sludge and water, particularly since coal sludge is concentrated?

E. Waste Disposal

1. Nature of content and disposal of solid waste

2. Certainly there will be waste materials such as ash etc. from the operation. What will be the disposal methods of this material?

F. Ecology - Wildlife Impacts

1. What will be the impacts on wildlife both at the plant and as a result of increased transportation on the highways?

2. Wildlife habitat conflicts created by Clean Air Act

3. Increased demand for hunting and fishing opportunities

4. Increasing urbanization in important wildlife habitats, particularly game winter ranges and deciduous woodlands along the Yampa River.

5. Threatened and endangered species - fish in Yampa River, bald eagles. Also, rare species such as the great blue heron, long-billed curlew and possibly others.

6. Increasing harassment and illegal taking of wildlife; also more frequent isolations and potentially violent confrontations with game and fish officers.

(Note: #2-6 are by Bill Clark, DOW)

G. Coal Sources and Coal Transportation

1. Traffic impacts, particularly due to hauling coal

2. Coal sources - possibility of Hayden Gulch coal? Use of Hayden Gulch-Hamilton Road? (Routt Co.)

3. Interested in the amount of coal that might come from South Hayden after full scale operation is attained. Highway 40 crossing is very slow for trains and holds up traffic on Highway and County Road 37.

4. Coal sources - all impacts associated with getting coal to synfuels plant

H. Other

1. How many acres of disturbance?

2. Automotive markets for county equipment: possibility?-reliability and conversion cost. (Routt Co.)

II. Topics Needing More Attention

A. May want to look at new Piceance Creek-Meeker Rail Study to evaluate rail availability and proposal for spur line to Axial. (For information, contact Carolyn Dinger at CWACOG, 625-1723.)

B. How many other similar plants may be constructed in this area?

C. Hazardous wastes and disposal

D. Long-term environmental impact on area

E. Relationship of all energy companies and interests present in Moffat Co. (i.e., coordination, intercommuncation)

F. Transportation of coal and water (if other than from Axial Basin)

G. Water - where from in specific terms as soon as possible

H. Water Supply

I. Market for methanol

J. Water supply - how it will be developed

K. Cumulative impacts on air quality

Additionally, a few comments appeared on the "worksheet" page:

1. What rights-of-way may be needed over public lands to deliver water to the site? This could cause delays if applications were filed too near need time. Early-on contact with BLM needed.

2. If water disposal is not to be in mines or on site, locations should be identified soon if permits from BLM are to be needed.

3. Archeological site on upper Collum Gulch has been submitted for possible National Register consideration. This could affect the plant site if the archeological site extends to lower Collum Gulch.

4. Will net energy analysis be done?

5. Impacts cross county lines and cause cumulative impacts. Grace project coincides with anticipated rapid growth in Meeker caused by oil shale. What does this do to Meeker? Can the town handle both? Tax base is in Moffat County while a portion of the impact is in Rio Blanco. Causes some problems in dealing with socio-economic impacts. How does Meeker pay for impacts? Should Grace help?

As noted above, the availability of additional information will encourage a continuing discussion of the issues related to this project. A second scoping paper will reflect this added discussion and, consequently, will not be prepared until all facets of the 500 TPD plant have been considered.

W. R. GRACE PROJECT - QUESTIONS, ISSUES AND CONCERNS

June 4, 1981

A. Please list the five issues or concerns which you think are most important and which should receive very thorough attention during review of the project. Be as specific as you can. (Use the other side if needed.)

1.

2.

3.

4.

5.

B. Are there other questions or topics which need to be covered more thoroughly at public meetings? What information needs to be developed more fully. (Use the other side if necessary.)

p

Exhibit 9

DEFINITE REGULATORY REQUIREMENTS

Methanol Facility:

Before Construction

-Prevention of Significant Deterioration	U.S. Environmental Protection Agency
-Emergency Procedures for Discovery of Archaeological Site	U.S. Department of the Interior
-Air Emission Permit	Colorado Department of Health
-New Source Performance Review Notification	Colorado Department of Health
-Approval of Location and Construction of Water Works	Colorado Department of Health
-Site Approval of Sewage Treatment Facility	Colorado Department of Health
-Underground and Utility Permit	Colorado Division of Highways
-Survey Permit	Colorado Division of Highways
-Review and Approval of Plans for LPG Storage	Colorado Division of Highways
-Certificate for Petroleum Transport and Storage	Colorado Division of Labor
-Underground and Utility Permit	County Road Department
-Driveway Permit	County Road Department
-Building Permit	County/City Building Official
-Conditional Use Permit	County Planning Department

Before Operation

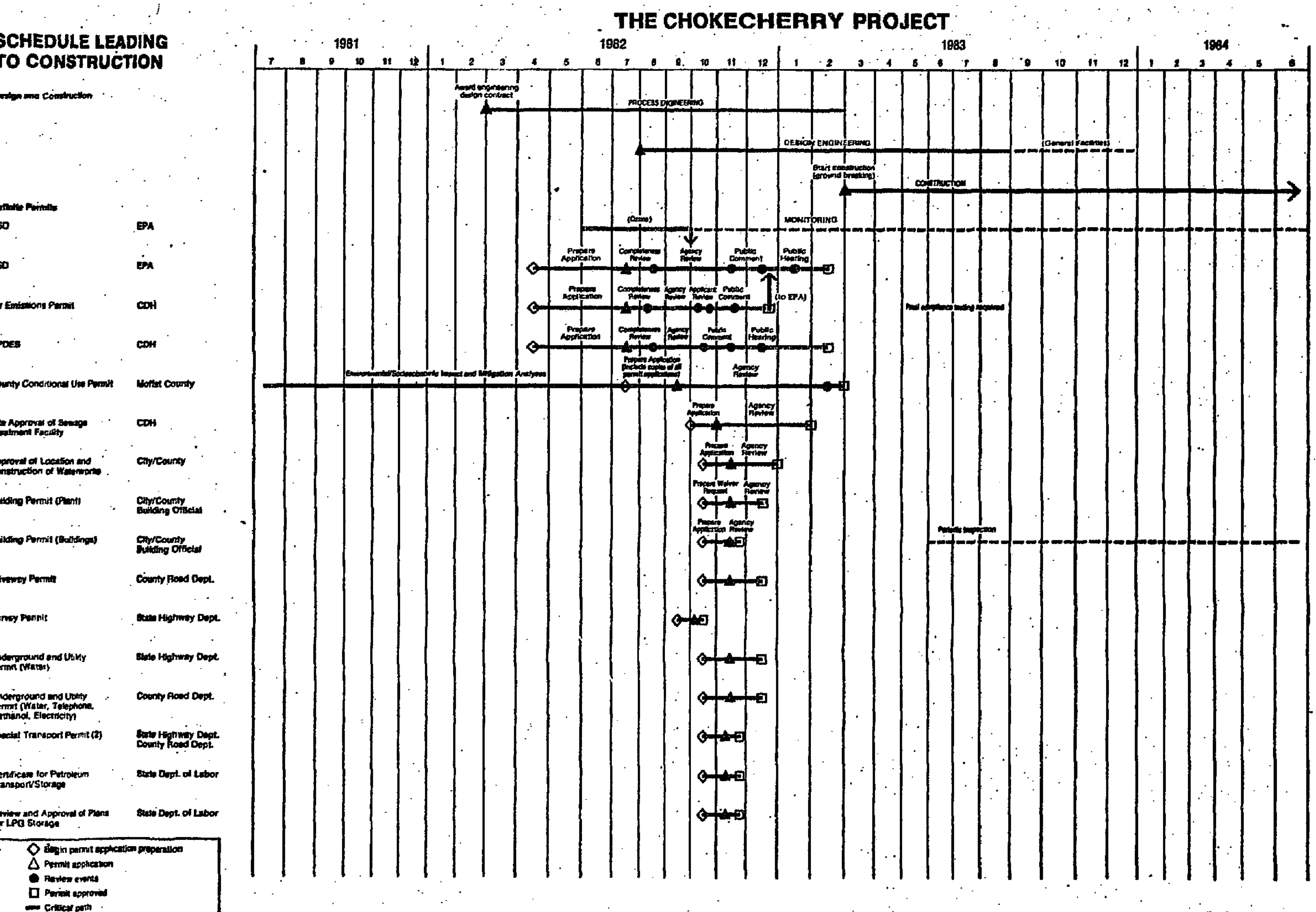
-Compliance with OSHA	U.S. Department of Labor
-Radio Licenses	Federal Communications Commission
-Compliance with Pipeline Safety Act	U.S. Department of Transportation

DEFINITE REGULATORY REQUIREMENTS (Continued)

-NPDES (no discharge)*	Colorado Department of Health
-Compliance with Noise Regulations	Colorado Department of Health
-Certificate for Boilers	Colorado Division of Labor
Methanol Load-Out:	
Before Construction	
-Emergency Procedures for Discovery of Archaeological Site	U.S. Department of the Interior
-Air Emission Permit	Colorado Department of Health
-Certificate for Petroleum Transport and Storage	Colorado Division of Labor
-Conditional Use Permit	County Planning Department
-Driveway Permit	County Road Department
-Septic System	County Sanitation Department
-Building Permit	City/County Building Department
Before Operation	
-Radio Licenses	Federal Communications Commission
-Compliance with OSHA	U.S. Department of Labor
-Compliance with Noise Regulations	Colorado Department of Health

*While the NPDES permit is not strictly required until plant operation begins, it is advisable to secure the permit prior to construction.

Exhibit 10



E.24

Exhibit 11

POSSIBLE PERMIT REQUIREMENTS

Coal-to-Methanol Facility

-404 Dredge and Fill Permit	U.S. Army Corps of Engineers
-Environmental Impact Statement (triggered by 404 permit)	U.S. Army Corps of Engineers
-Hazardous Waste Permit	U.S. Environmental Protection Agency
-Migratory Bird Permit	U.S. Fish and Wildlife Service
-Section 7 Consultation	U.S. Fish and Wildlife Service
-Open Burning Permit	Colorado Department of Health
-Special Transport Permit	Colorado Division of Highways
-Special Transport Permit	County Road Department

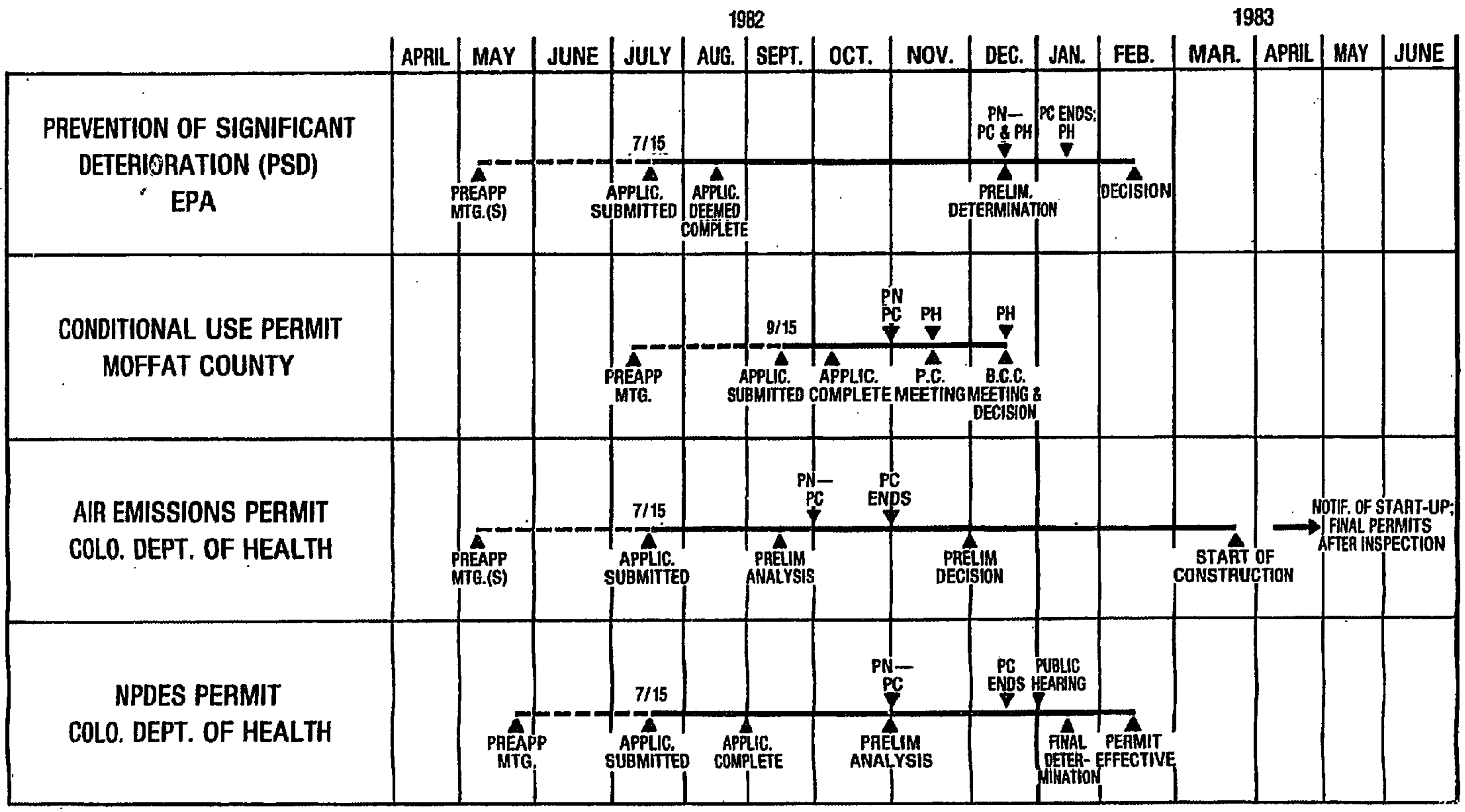
Exhibit 12

REGULATORY REQUIREMENTS DETERMINED NOT TO BE APPLICABLE

-Toxic Substances Control Act	U.S. Environmental Protection Agency
-Rights of Way	U.S. Department of the Interior, Bureau of Land Management
-Explosive Users Permit	U.S. Department of Treasury
-Rights of Way	State Board of Land Commissioners
-Approval of Plans for Reservoir	Colorado Division of Water Resources
-Permit to Construct an Erosion Control Dam	Colorado Division of Water Resources
-Well Construction Permits	Colorado Division of Water Resources
-Access to State Highway	Colorado Division of Highways
-Permit for Contract Carrier	Public Utilities Commission
-Compliance with Hazardous Materials Regulations	Public Utilities Commission
-Permit for Explosive Materials	Colorado Division of Labor
-Certificate of Designation	County Board of Commissioners/ Department of Health
-Permission to Cross Private Pipeline	Texaco

EXHIBIT 13

Colorado Joint Review Process—Project Decision Schedule
W. R. Grace Coal to Methanol Plant



KEY

PN	PUBLIC NOTICE
PC	PUBLIC COMMENT
PH	PUBLIC HEARING
P.C.	PLANNING COMMISSION
B.C.C.	BOARD OF COUNTY COMMISSIONERS

APPENDIXES

Appendix	Title
A	KBW Feasibility Study
B	KBW Tradeoff Studies
C	Pipeline Report
D	Siting Report
E	Air Quality Report
F	Hydrology Report
G	Geotechnical Report
H	Solid Waste Report
I	Aquatics Report
J	Wildlife Report
K	Vegetation Report
L	Soils Report
M	Cultural Resources Report
N	Socioeconomic Report
O	Regulatory Report

☆U.S. GOVERNMENT PRINTING OFFICE: 1982-546-085/3136