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**COMMERCIAL PRODUCTION OF ETHANOL IN THE SAN LUIS VALLEY,
COLORADO**

Final Report

By
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July 1983

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Westec Services, Inc.
San Diego, California

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FINAL REPORT

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JULY 1983

**PREPARED FOR THE
IDAHO OPERATIONS OFFICE
U. S. DEPARTMENT OF ENERGY
DIVISION OF GEOTHERMAL ENERGY
UNDER COOPERATIVE AGREEMENT NUMBER
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ABSTRACT

The purpose of this study is to assess the commercial feasibility of producing between 76 and 189 million liters (20 and 50 million gallons) of ethanol annually in the San Luis Valley, Colorado using geothermal energy as the primary heat source. The San Luis Valley is located in south-central Colorado. The valley is a high basin situated approximately 2316 meters (7600 feet) above sea level which contains numerous warm water wells and springs. A known geothermal resource area (KGRA) is located in the east-central area of the valley. The main industry in the valley is agriculture, while the main industry in the surrounding mountains is lumber. Both of these industries can provide feedstocks for the production of ethanol.

ACKNOWLEDGEMENT

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THE UNITED STATES OF AMERICA
DEPARTMENT OF THE INTERIOR
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EXECUTIVE SUMMARY

The results of this study indicate that it would not be profitable to produce ethanol in the San Luis Valley, Colorado utilizing a geothermal resource even if the existence of a reasonably good geothermal resource can be confirmed.

To date a full-scale geothermal exploration/confirmation program has not been conducted in the valley and it is necessary therefore to make projections concerning the location and nature of the resource. The basis for the projections is old data from oil/gas exploration wells which points to the existence of a resource in the eastern part of the valley with temperatures in the range of 150°C (302°F) to 165°C (330°F). Well flow rate data is for all practical purposes non-existent and it has been presumed that flow rates of 1135 liters (300 gallons) per minute to 2270 liters (600 gallons) would be realized from wells using standard size casing.

The conventional energy saved by using geothermal energy to produce 189 M liters (50 MM gallons) of ethanol in the San Luis Valley would be the equivalent of approximately 975,000 barrels of oil annually.

Project capital cost estimates for a geothermal-ethanol plant for producing ethanol in the San Luis Valley from grains and/or potatoes totalled \$177,000,000 for a 189 M liter (50 MM gallon) facility. Mixes of potatoes and grains as feedstocks are highly desirable because potatoes are net water producers. In this region water supplies are critical. The analysis shows that, even with a very optimistic assumption regarding ethanol price escalation, ethanol can only be produced economically from geothermal energy utilizing a barley feedstock. Corn, wheat and potatoes are unacceptable as feedstocks due to their relatively high market prices.

The optimism assumed in developing the economic analysis cannot be justified. In addition, major practical problems exist that could add significantly to the cost of the project. Therefore, one can conclude from this analysis that a geothermal-ethanol facility developed in the San Luis Valley of Colorado would not be cost-effective. It is recommended that no follow-on field experiment be initiated for this project.

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SECTION 1 INTRODUCTION

1.1 STATEMENT OF OBJECTIVES

1.1.1 Overall Objective

The overall objective of this study is to determine the engineering, economic, environmental and institutional feasibility of utilizing a moderate to high temperature geothermal heat source for the production of fuel grade ethanol on a commercial scale in the San Luis Valley, Colorado. A secondary objective is to develop the engineering and economic techniques in the direct use application of geothermal energy for ethanol production in anticipation that these techniques will be of value to the numerous other sites where a geothermal resource exists in or near large agricultural areas.

1.1.2 Specific Objectives

The specific objectives of this study are as follows:

- a) Assemble and review all geothermal resource data available and prepare a preliminary resource evaluation based on existing data for the area.
- b) Develop a plan for resource confirmation.
- c) Develop an engineering approach for the production of ethanol with a moderate to high temperature (150-205°C (300-400°F)) geothermal resource.
- d) Identify the preferred biomass feedstocks for the ethanol process based on availability, ethanol production value, and cost.
- e) Determine the heat transport methods for converting geothermal heat to process heat for the commercial production of fuel grade ethanol.
- f) Determine the optimum size of the facility based on the available resource, feedstocks, transportation and commercially available equipment.
- g) Prepare cost estimates for the facility capital and operating costs (less feedstocks) for each alternative engineering approach considered feasible.

- h) Develop a comprehensive energy balance for the entire facility and determine the specific benefits of geothermal heat utilization in terms of equivalent fossil fuel and electricity savings.
- i) Develop a conceptual design of a commercial ethanol production facility utilizing geothermal energy as its principal energy source.
- j) Evaluate the sensitivity of the economic analysis to changes in geothermal parameters, interest rates, feedstocks, supply water availability and electricity costs.
- k) Determine the life cycle costs of the facility based on estimates of capital, operations and maintenance, and feedstock costs and anticipated ethanol product and by-product market values.
- l) Provide an analysis of the environmental aspects of the development and operation of the proposed facility.
- m) Provide an analysis of the institutional barriers and factors relating to the proposed facility including, specifically, water rights.
- n) Provide a final report which addresses the feasibility of utilizing geothermal energy at San Luis for the commercial production of fuel grade ethanol and, if it is technically, economically and environmentally feasible, provide a specific contingency plan that describes the necessary steps leading to the construction and operation of a follow-on field experiment which might be required to demonstrate technical viability.

1.2 SCOPE

The final report on the Commercial Production of Ethanol in the San Luis Valley documents the technical, environmental, institutional and economic analyses of manufacturing ethanol with geothermal energy used for process heat. Section 2 evaluates ethanol production techniques and identifies temperature requirements for process steps that would be adapted to the use of geothermal energy. Section 3 addresses regional considerations including a preliminary evaluation of the characteristics of a geothermal resource, a reservoir confirmation plan to establish the presence of an acceptable resource, the logistics of feedstock availability and supply, water requirements and rights, institutional and environmental considerations and associated mitigation measures. Section 4 addresses the initial considerations of the ethanol process and

identifies design constraints for the geothermal adaptation of the production techniques. Section 5 discusses the geothermal system and wellfield design. Section 6 presents the economic analysis of an ethanol plant in the San Luis Valley and Section 7 details a conceptual design of an ethanol production facility adapted to geothermal energy utilization.

1.3 SUMMARY AND CONCLUSIONS

The San Luis Valley is located in south-central Colorado. The valley is a high basin, situated approximately 2316 meters (7600 feet) above sea level, which contains numerous warm water wells and springs. A known geothermal resource area (KGRA) is located in the east-central area of the valley.

Stratigraphically the San Luis Valley basin consists of two north-south trending grabens separated by a central horst block. The basement of the western Monte Vista graben is about 3050 meters (10,000 feet) beneath the valley floor. It is separated from the eastern Baca graben whose basement is up to 5790 meters (19,000 feet) beneath the valley floor by the Alamosa horst. The Alamosa horst is a buried north-south trending ridge whose crest is about 1645 meters (5400 feet) beneath the valley floor. No organized full-scale geothermal exploration/confirmation program has been conducted in the valley to date. Therefore, the characteristics of the San Luis Valley geothermal resource are not well defined. Several oil/gas exploration wells have been drilled which provide clues to the characteristics of the resource. Data from these wells indicates that the maximum temperature in the Monte Vista graben is about 120°C (250°F) at the bottom of the basin -- 3050 meters (10,000 feet). Data from wells in the Baca graben indicates 150°C (302°F) at the same depth with a gradient that points to the potential for higher temperatures at greater depths. Geothermal flow test data and resource quality data are either not available or of limited value. It has been necessary therefore to make the following assumptions about the characteristics of the resource:

- a. At depths in excess of 3050 meters (10,000 feet) in the Baca graben, temperatures in the range of 150°C (302°F) to 165°C (330°F) would exist.
- b. Flow rates from wells drilled to this depth with standard size casing would be in the range of 1135 liters (300 gallons) per minute to 2270 liters (600 gallons) per minute.
- c. Total dissolved solid content of the resource of about 4000 milligrams per liter (4000 parts per million).

Based on these assumptions a conceptual design for a geothermal-ethanol plant is provided which uses grains and potatoes as feedstocks. These feedstocks were selected because both are grown locally. The principle grains grown in the area are barley and winter wheat. The total valley production of these two grains for a recent typical year could produce about 90 M liters (23 MM gallons) of ethanol annually. In addition, the total potato crop for a recent typical year could produce another 60 M liters (16 MM gallons) annually for a net potential of 150 M liters (39 MM gallons). However, since only a fraction of the total would be expected to be available and since the total is insufficient to support the maximum sized facility under study, importation of grains has been assumed. Corn, wheat and feed barley were identified as the grains that could be imported at a price competitive with local crops and are used in making cost estimates.

A net savings in fossil fuel is realized from two sources: (1) energy otherwise used to provide heat and (2) the energy required to refine 189 M liters (50 MM gallons) of gasoline. The total amount of fossil fuel that would be replaced by the production of 189 M liters (50 MM gallons) of ethanol using geothermal energy as the primary heat source is estimated to be the equivalent of 975,000 barrels of oil.

Project capital cost estimates for the assumed resource characteristics and feedstocks totalled \$177,000,000 for a 189 M liter (50 MM gallon) facility. Cost estimates for a range of annual production capacities were conducted. The results indicated that there is an economy of scale with higher plant capacities but no optimum size. The cost per liter (gallon) of annual production capacity should decrease with size and higher resource temperature and flow rates. The rate of change of this decrease will be much higher at lower temperatures and flow rates due to the effects of the cost of the geothermal well system on the overall cost of the project.

The discounted cash flow rate of return (DCFROR) of a geothermal-ethanol project was evaluated throughout a range of plant capital costs and feedstocks. Mixes of potatoes and grains as feedstocks are highly desirable because potatoes are net water producers due to their high water content. By comparison, the production of ethanol from grains consumes water. A production mix which results in about 12 percent production from potatoes and 88 percent production from grains results in a non-consumptive water balance for the facility. In this region this is a highly desirable situation due to the criticality of water supplies. However, the analysis indicates that, even with a very optimistic assumption about ethanol price escalation, ethanol can only be produced

produced from potatoes is kept lower than 2 to 3 percent and the balance of the feedstock is barley, only. Both corn and wheat are too expensive a feedstock to produce ethanol economically utilizing geothermal energy.

Sensitivity analyses of the cost of ethanol production showed that the cost is most sensitive to the cost of feedstocks, geofluid, and drilling; the price of ethanol and by-products; and the differential escalation rate between the ethanol price and general inflation. The optimism assumed in developing the economic analysis cannot be justified in light of contradicting facts combined with the sensitivity of DCFROR to the assumptions. In addition, major practical problems exist, particularly regarding the availability of water, feedstocks, an adequate geothermal resource, and a stable market for the ethanol plant products, which could add significantly to the cost projections estimated for such a facility. Therefore, one can conclude from this analysis that it is highly probable that a geothermal-ethanol facility developed in the San Luis Valley of Colorado would not provide the minimum rate of return required for such an investment. It is recommended that no follow-on field experiment be initiated for this project.

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SECTION 2

GENERAL EVALUATION OF ETHANOL PRODUCTION TECHNIQUES

2.1 BACKGROUND

Industrial alcohol was an outgrowth of alcoholic beverages, but now it has become important as a solvent, an ingredient for other chemicals and recently as an alternative automobile fuel. The production of ethanol for use as a fuel is not a new concept. The original Ford Model-T was capable of using alcohol as a fuel and, during World War II, nations on both sides relied heavily on alcohol fuels. The United States ordered several beverage distilleries to modify their plants to produce anhydrous ethanol to supplement other fuels when petroleum products were in short supply. Although originally viewed as an ideal fuel because it is manufactured from a renewable commodity and it stabilizes the market for farm crops, ethanol could not survive the direct competition from gasoline and the demand for ethanol as a motor fuel largely disappeared after the 1950s.

As petroleum prices continue to escalate and the pressure increases to gain energy independence from foreign suppliers, ethanol has again surfaced as a potential fuel, most notably for automobiles. Ethanol is one of the most promising alternatives to fossil fuels that can be produced in the near-term. Fermentation ethanol has become the first non-petroleum fuel to attain widespread use in the United States through the sale of gasohol, a blend of 10 percent anhydrous ethanol and 90 percent gasoline. Of the 303 million liters (80 million gallons) of fermentation alcohol produced in 1979, 189 million liters (50 million gallons) were blended to obtain gasohol (Solar Energy Research Institute, 1980). This product can be used in conventional internal combustion engines without major modifications with no resultant effect on engine performance.

Conventional production techniques are generally not energy efficient. Therefore, one major issue for future ethanol production facilities is to minimize conventional fuel required for the process steps in order to make the synthetic fuel substitution as attractive as possible. Most of the industrial alcohol currently manufactured is produced from ethylene, which is a petroleum product, so the replacement value of fermentation alcohol becomes even more attractive.

This study will address the feasibility of utilizing geothermal fluid as the prime energy source for the ethanol production process. A review of the industrial processing geothermal direct use data base and commercial ethanol production methods was conducted for application to the San Luis Valley Ethanol Plant. The main

parameters for the conceptual design of the plant, and areas that require additional research are discussed in this section.

2.1.1 Octane Improvement and Emissions

Although ethanol has less thermal energy than gasoline, the addition of ethanol to gasoline increases the octane rating of the mixture because anhydrous ethanol is a high octane fuel. Gasohol improves the octane number of 90 octane gasoline by two or three points. (Katzen Associates, 1978). The octane rating of gasoline could be boosted through the use of ethanol rather than the use of tetra-ethyl lead thereby eliminating the harmful emissions associated with lead. Another interesting aspect of the use of gasohol is that it allows for the production of more gasoline per barrel of crude oil. This is so because producing higher octane unleaded fuel requires more energy at the refinery than the lower octane fuels, therefore reducing the yield per barrel.

The Alcohol Fuel Information Center gives emission data based on the combustion of ethanol, gasoline and gasohol in grams per mile of particular pollutants. As shown below gasohol combustion significantly reduces the hydrocarbons and carbon monoxide emissions and slightly increases the nitrogen oxide emissions.

Table 2-1
COMBUSTION EMISSIONS

<u>Emissions (gms/mile)</u>	<u>100% Ethanol</u>	<u>Gasohol</u>	<u>Gasoline</u>
Hydrocarbon	2.50	2.3	3.32
Carbon Monoxide	17.00	20.7	49.37
Nitrogen Oxides	1.66	2.3	1.86
Acetaldehyde	0.16	no data	0.05

The overall environmental impact of the combustion of gasohol in internal combustion engines has yet to be determined and requires additional research.

2.2 FEEDSTOCKS

To identify critical plant equipment, water requirements, energy requirements for initial processing and the expected daily capacity of the plant, the feedstocks that will comprise the raw material for the ethanol plant must be determined. Raw materials from which ethyl alcohol may be made fall into two general classifications: 1) hydration of petrochemicals (inorganic); and 2) fermentation of biomass (organic) (see Figure 2-1).

2.2.1 Petrochemical Hydration: Ethylene

The majority of ethanol produced in the United States is manufactured by the chemical conversion of the compound ethylene ($\text{CH}_2\text{:CH}_2$), which is normally derived from petroleum refining. Two synthetic processes are used commercially and the following are the reactions for ethyl hydrogen sulfate conversion and vapor-phase direct-hydration (Shreve and Brink, 1977).

1. Ethyl Hydrogen Sulfate

Potential problems exist with the highly corrosive atmosphere of the sulfuric acid.

2. Vapor-Phase Direct-Hydration

The direct-hydration process passes ethylene and water over a fixed bed catalyst such as aluminum hydroxide gel, phosphoric acid on diatomaceous earth, or tungstic acid on silica gel.

Ethanol Production Techniques

**FIGURE
2-1**

To obtain anhydrous ethanol, the process for azeotropic distillation follows either of these conversion techniques to remove the water from the mixture.

2.2.2 Biomass Fermentation

Beverage alcohol is manufactured by the fermentation of organic materials. The basic technique is to break the bonds between individual molecules of glucose in sugars, starches, or cellulose. Plants use starches or cellulose for long-term storage of the glucose they manufacture through photosynthesis. Reducing the starches or cellulose to fermentable sugars is accomplished by treatment with microorganisms and enzymes, or in some cases acid hydrolysis. The initial processing steps for the different feedstocks differ slightly, but most of the major process equipment is identical after preliminary size reduction and chemical treatment. The main process stream is considered to be the one containing the highest concentration of ethanol. By-products of the system will be Distillers Dried Grains (DDGs), fusel oils (alcohols of higher weight), and light ends (aldehydes and other process contaminants).

2.2.2.1 Saccharification for Grains and Cereals

After initial processing, the starch in the cereals or grains must be reduced to a simpler carbohydrate, glucose, for fermentation. The process steps for ethanol production from grains or potatoes are shown in Figure 2-2. The enzyme alpha-amylase is added to the starch slurry to break down starches into dextrins. The temperature of the mash is raised to 60°C (140°F) by recycling waste heat from the distillation and dehydration processes. During this time, the pH is adjusted and maintained at 6.5 for optimum enzyme reactions. The saccharification process, also referred to as the cooking process, releases the starch from the grain cell walls with the addition of heat. Glucoamylase is added at this point to break the starch bonds to produce glucose. The ideal cooking temperature is between 130-150°C (265-302°F). The normal technique for cooking the starchy materials for the ethanol process is to pump the mash (water and ground raw materials) through an ejector where it is instantaneously heated to the cooking temperature by the addition of steam. The heated mash is maintained at this temperature for 5-15 minutes.

The mash is then flash cooled to 85°C (185°F) which releases steam used for preheating at other places in the ethanol production process. The mash is maintained at this temperature for approximately one hour and then flash cooled in a vacuum tank to 65°C (149°F). This mash is then ready to proceed to the fermentation phase of grain alcohol production.

Ethanol Production for Amylaceous materials

**FIGURE
2-2**

2.2.2.2 Cellulosic Conversion

In the search for a supplement to conventional fuel sources, increased attention has been focused on the ethanol production market. The major sources of industrial ethanol in the United States are ethylene and the fermentation of sugars or grains. Forest and crop residues present a disposal problem. Every year millions of tons of crop and forest residues are burned in open fields. In addition to aesthetic considerations, odors, reduced visibility and possible health effects make this method of disposal unattractive. Lignocellulose is being seriously considered as an alternative to traditional ethanol feedstocks.

The value of grains as a food source and the price and availability of ethylene are negative factors for ethanol production. Because of the limited commercial value of residual forest, pulp or paper wastes and municipal solid waste, the feedstock costs for a cellulose plant would be extremely low. However, in order to use lignocellulose, fermentable sugars must be first liberated and separated from the lignin and hemicellulose fractions of the feedstock.

Most current processes for cellulosic conversion are energy intensive. There are three primary approaches to the liberation of sugars in the lignocellulose; weak acid, strong acid and enzymatic hydrolysis.

Weak acid hydrolysis such as the Madison-Scholler process (Yu, 1980) uses 0.5 percent sulfuric acid at relatively low temperatures of 140-190°C (284-374°F) to degrade the cellulose. At higher temperatures and shorter retention times (500°C; 932°F), weak acid hydrolysis results in a higher glucose yield. The temperatures required for either of these conversion techniques exceed the expected temperature of the geothermal reservoir in the San Luis Valley.

Strong acid hydrolysis uses a sulfuric acid concentration between 70 and 80 percent to hydrolyze the cellulose bonds at temperatures between 10 and 45°C (50-113°F) (Oshima, 1965). Economic feasibility requires acid recovery. Generally the acid recovery operations are highly energy intensive. Acid hydrolysis creates a corrosive atmosphere for all equipment used in the processing steps. Special materials and construction techniques may lessen the severity of the attack on holding vessels and other process equipment. The additional cost for capital equipment and the safety hazards associated with strong acid hydrolysis preclude the use of this process until cellulose conversion and acid recovery become economically attractive.

Some of the problems of cellulose as an ethanol feedstock arise because of the undesirable by-products (degradation) formed during conversion to glucose.

Additional catalysts are added before hydrolysis to circumvent any problems associated with these waste materials which can inhibit the fermentation process. In general, increased rates of production lead to increased rates of degradation.

Enzymatic hydrolysis of cellulose has been gaining impetus in the United States. The enzymes are very selective for the specific substrate cellulose. In order for the enzyme to attack the bonds of the lignocellulose, pretreatment of the feedstock is required to remove hemicellulose and lignin. The rejected material from pulp processing has been chemically treated and may be ideal as a feedstock for the production of cellulose fibers relatively free from lignin and hemicellulose. However, in general, chemical pulping is expensive compared to other methods.

A technology that combines enzyme hydrolysis with simultaneous fermentation to ethanol resulting in increased yields and simplified processing is ready for demonstration (Horton et al., 1980). Genetic improvements in yeasts and enzymes may improve the conversion systems or optimize the technology for specific feedstock conditions.

Another source of potential problems is the low glucose yield after degradation of the cellulose. The fermentation cycle produces a beer with an ethanol concentration of only 2 percent, the low concentration requires large energy inputs for the distillation and dehydration phases. After conversion to glucose, the normal fermentation process and subsequent processing steps in processing alcohol are identical to those used for conventional feedstocks (see Section 2.2.2.3).

The basic challenge of finding an economically acceptable conversion technology from cellulose to glucose continues, but major strides in the development of an enzymatic cellulose hydrolysis process increase the potential of cellulose as a feedstock for ethanol production. A continuous feedstock supply and advanced conversion technology is required to justify the heavy capitalization costs of a cellulosic ethanol plant.

2.2.2.3 Fermentation

After the starch has been released from the cell walls and has been converted to glucose, the mash is cooled to 30°C (86°F) for the fermentation process. The material used as a substrate for the fermentation process is glucose. The principal reaction in fermentation is:

The yeast normally used in industrial fermentation is *saccharomyces cerevisia* which has been cultivated to operate most efficiently in acidic conditions at 30°C. Wild yeast strains and bacteria do not thrive in acidic conditions, so contamination is minimized. As the reaction proceeds, heat is evolved which must be dissipated to prevent sterilization of the yeast culture. The peak temperature must not exceed 35°C (95°F). The normal fermentation cycle requires 40-60 hours retention in the fermentation vats to convert the glucose to ethanol. Normally, a 92 percent conversion from glucose to ethanol can be achieved under process conditions. The percentage of alcohol in the beer leaving the fermentation phase is dependent on the percentage of dry solids in the mash and usually ranges from 6-11 percent alcohol by weight. The rule of thumb for determining alcohol content is: 2 percent dry solids produces 1 percent of alcohol by weight in the beer. The dry solids content is limited, primarily by viscosity of the mash, at 22 percent by weight.

By-product contaminants include higher weight alcohols, succinic acid, glycerol and aldehydes. These products are not formed in appreciable quantities and are removed at later stages in the ethanol process. The remaining steps in the production of anhydrous ethanol consist of concentrating the ethanol by removal of water and other impurities in the process stream.

2.2.3 Feedstock Choice for San Luis Valley Ethanol Plant

In order to provide some insulation from abnormal price fluctuations or a severe supply shortage for a particular feedstock for the San Luis Valley Plant, a feedstock mix was selected, the proportions of which would be determined by market forces. The agricultural composition of the valley and the similarity of processing for starchy materials resulted in the choice of wheat, barley, corn, or potatoes as feedstocks for the ethanol plant. These feedstocks will all require six major process steps: 1) cleaning and size reduction; 2) cooking or liquefaction; 3) saccharification; 4) fermentation; 5) distillation; and 6) dehydration. The details of the conceptual design for the site specific ethanol plant are discussed in Section 7.

2.3 DISTILLATION AND DEHYDRATION

Ethanol used as motor fuel must be purified to 99.9 percent alcohol. This process step is required for ethanol produced from the fermentation of biomass or the hydration of petrochemicals. The removal of water is accomplished through a series of successive distillation steps which concentrate the alcohol through reflux. Alcohol cannot be made stronger than 95.6 percent by rectification because water and alcohol

form a binary constant-boiling mixture (azeotrope) of this composition which boils at a slightly lower temperature than absolute or anhydrous alcohol.

In order to remove the remaining 4-5 percent water present in this azeotrope, a third component is normally used to break the azeotrope. The normal dehydration process steps are shown in Figure 2-3. A hydrocarbon is commonly used in industrial ethanol operations to form a ternary minimum boiling azeotrope with water and ethanol. Anhydrous alcohol is obtained from the bottom of the distilling column because its vapor pressure is relatively lower than that of the constant-boiling mixture of ethanol, hydrocarbon and water. The ternary azeotrope is stripped of its hydrocarbon and ethanol content and these components are returned to the dehydration column.

2.4 ALTERNATIVES TO CONVENTIONAL PRODUCTION TECHNIQUES

The production of industrial alcohol by fermentation has evolved from the manufacturing processes of the beverage distilleries. These plants are concerned primarily with taste, and efforts have not been directed towards optimizing heat conservation and production rates, but have been focused primarily on manufacturing a palatable product. The key to improving the economics of industrial ethanol plants is to concentrate on techniques that are specifically geared towards the formation of 200 proof ethanol.

2.4.1 Microorganisms

The subjective criterion of taste is eliminated from consideration in anhydrous ethanol production. The aldehydes and ketones which give beverage grade alcohol its flavor are considered contaminants in producing 200 proof ethanol and must be removed, which requires additional process steps and increased operating costs. The yeast and enzymes currently used could be modified to accommodate the requirements of a fuel grade ethanol plant. Recent laboratory research has discovered that the bacterium *Zymomonas mobilis* used in the fermentation cycle can produce fuel grade alcohol two to three times faster than the same amount of yeast (University of New South Wales, Australia, 1981). These microorganisms could be tailored to increase alcohol production rates, minimize by-product formation and function in an environment conducive to the overall ethanol process. Applicability to industrial scale plants has not been demonstrated.

2.4.2 Fermentation

Several techniques have been put forward to improve fermentation characteristics. Yeast growth and sugar conversion are inhibited by alcohol formation, and

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C₂H₅OH - 96.0%
C₆H₆ - 0%
H₂O - 4.0%

C₂H₅OH - 18.5%
C₆H₆ - 74.1%
H₂O - 7.4%

78.2°C
C₂H₅OH - 96.0%
H₂O - 4.0%

SEPARATOR EQUILIBRIUM

	TOP LAYER	BOTTOM LAYER
VOL. % OVERHEAD	84.0	16.0
COMPOSITIONS		
C ₂ H ₅ OH	14.5%	63.0%
C ₆ H ₆	84.5%	11.0%
H ₂ O	1.0%	38.0%

REFERENCE:
CHEMICAL PROCESS INDUSTRIES p. 636
R. NORRIS SHREVE AND JOSEPH A. BRINK JR
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Ethanol Dehydration with Benzene

**FIGURE
2-3**

many methods have been advanced to optimize fermentation. One approach is to remove alcohol as it is formed by nitrogen sparging. The other more common practice is vacuum fermentation. The yeast culture is sterilized at 78°C (173°F), the atmospheric alcohol boiling temperature. Evacuating the fermentor to 1.8 psia would lower the boiling point of ethanol to 30°C, the optimum temperature for fermentation. In vacuum fermentation, the heat generated by the exothermic process of sugar conversion could vaporize the liquid product ethanol and reduce the energy requirements of the subsequent distillation process. The ethanol concentration evolved from the fermentor could eliminate the mash column and save up to 2674 kilocalories/liter (40,000 Btu/gallon) of anhydrous ethanol produced. Feasibility involves balancing the electro-mechanical power required to maintain a vacuum with the heat energy savings.

2.4.3 Distillation and Dehydration

The conversion of beer to absolute alcohol requires 75 percent of the energy consumed in alcohol production. Unmodified, the beer still, mash column, rectification and drying columns consume 5561 kilocalories/liter (83,200 Btu/gallon) of fuel grade ethanol. This is greater than the heating value of ethanol 5214 kilocalories/liter (78,000 Btu/gallon), therefore, heat conservation techniques must be implemented, and improvements in dehydration and distillation techniques must be an object for continued research. If ethanol manufactured using conventional fuels is to be used as an economic alternative to these fuels, it must be able to replace more conventional fuel energy than it consumes in production.

Dehydration techniques suggested to improve the heat balance of the overall process include solvent extraction with gasoline (currently under patent application), the use of regenerative water absorbers and crystallization of the water from the azeotropic water/ethanol mixture. Less latent heat is required to freeze water than to boil ethanol or water, so crystallization could represent an energy savings. Significant energy-saving techniques have been tested on laboratory-scale equipment, and the next step will be to prove these processes on demonstration and commercial sized units.

SECTION 3

REGIONAL CONSIDERATIONS

3.1 THE GEOTHERMAL RESOURCE

A search of published literature was conducted to establish an understanding of the geology, geophysics and hydrochemistry in the San Luis Valley. The information obtained from this search is the basis for the review which follows.

The development partnership that was in effect at the time that this feasibility study began is no longer viable and leaseholdings acquired for geothermal ethanol plant development have since been abandoned. Therefore, the geothermal resource analysis in this section is generic in nature and not site-specific as originally intended. In addition, the possibility of a follow-on field experiment to demonstrate technical viability no longer exists and, therefore, contingency plans for such a demonstration are not developed in this section.

3.1.1 Geology

The San Luis Valley of south-central Colorado is a portion of the San Luis basin which also includes the Taos Plateau in north-central New Mexico. To the east of the basin is the Sangre de Cristo Range. To the west of the basin are the San Juan Mountains in Colorado, and the Tusas Mountains in New Mexico. The basin is one of several large grabens within the Rio Grande rift. The generally accepted subdivision, as shown in Figure 3-1, includes five physiographic provinces: the Alamosa Basin, the San Luis Hills, the Taos Plateau, the Costilla Plains, and the Culebra Re-entrant.

The basin is filled with sediments from the Sangre de Cristo and San Juan Mountains. The valley-fill is composed of consolidated clay, silt, sand and gravel interbedded with volcanic flows and tuffs. The deepest portions of the valley-fill are in the eastern sections of the basin along the Sangre de Cristo Mountains and are considered to be up to 5790 meters (19,000 feet) deep. The basement complex within the graben is Precambrian granite, schist, and gneiss.

The basin is interrupted by two intrarift horst blocks: the San Luis Hills and the Alamosa horst. The San Luis Hills, as seen in Figure 3-1, run generally east by northeast across the basin and form a physiographic barrier as well as a structural divide between the San Luis Valley to the north and the Taos Plateau to the south. The Alamosa horst is a buried ridge which extends northward from the San Luis Hills. The crest of the ridge is about 1645 meters (5400 feet) beneath the valley floor. The ridge divides the western Monte Vista graben from the eastern Baca graben. Figure 3-2

Physiographic Subdivisions of the San Luis Basin

**FIGURE
3-1**

Typical Structural Interpretation of the Structure of the Alamosa Basin

**FIGURE
3-2**

shows the typical structural interpretation of the Alamosa Basin (San Luis Valley). The maximum basement depths of the two grabens as interpreted from the literature indicate that the Monte Vista graben basement would be a maximum of about 3050 meters (10,000 feet) deep to the west of the Alamosa horst while the Baca graben basement would be at most 5790 meters (19,000 feet) deep about 16 kilometers (10 miles) northwest of Great Sand Dunes National Monument. It has been suggested (Burroughs, 1980) that one or more east-west trending saddles may exist in the Alamosa horst to the north of the city of Alamosa.

The stratigraphic section, as depicted in Figure 3-3, of the basin is composed of 4 to 5 major rock formations. At the top is the Alamosa Formation; next is the Santa Fe Group which overlies and intertongues with the Los Pinos Formation; below the Los Pinos is the Vallejo Formation which in turn overlies volcanoclastic and volcanic rocks.

a. Alamosa Formation

The Alamosa Formation is a series of blue clays interstratified with water-bearing sands which divide most of the Alamosa basin into an unconfined (upper) and confined (lower) aquifer. Figure 3-4 shows the approximate limits of the clay. The clays are thickest in the northern end of the basin. The peripheral area outside the clay limit is an aquifer recharge area whose waters charge both the confined and unconfined aquifers. Burroughs (1980) reported logging 625 meters (2050 feet) of Alamosa Formation in the Mapco-Amoco well. The formation consisted in the first 55 meters (180 feet) of loose, well-sorted sand. From 55 meters (180 feet) to 98 meters (320 feet) blue-gray fresh water clays were encountered. From 98 meters (320 feet) to 543 meters (1780 feet) the lake clays changed to a greenish-gray. From 543 meters (1780 feet) to 625 meters (2050 feet) the greenish-gray clays were mixed with very coarse sand.

b. Santa Fe Group

Rocks of the Santa Fe Group are found beneath the Alamosa Formation throughout most of the Alamosa basin. The Santa Fe Group is composed of pinkish-orange clays interbedded with silty sands. The sand grains consist generally of quartz, volcanic rock fragments (VRF), plutonic rock fragments (PRF) and metamorphic rock fragments (MRF). The mix varies locally with one or the other becoming dominant based on the respective sources. The San Juan Mountains are the source of VRFs, with the Sangre de Cristos providing the PRF and MRF. The group thins from west to east in conjunction with a corresponding thickening of the underlying Los Pinos Formation.

Alamosa Basin Stratigraphic Section

**FIGURE
3-3**

Burroughs (1980) reported that the Santa Fe is 853 meters (2800 feet) thick at the Mapco-Amoco well. It thins to 213 meters (700 feet) over the Alamosa horst, expands in the Monte Vista graben, and then pinches out on the flanks of the San Juan Mountains.

c. Los Pinos Formation

The Los Pinos Formation is in general a sandy gravel with soft volume caniclastic sandstones interbedded with tuffaceous material. Individual sand beds are typically about 1 to 15 centimeters (1 inch to 6 inches) thick with some as thick as 25 centimeters (1 foot). This formation is believed to have been developed through the overlaying of alluvial fans along the eastern flanks of the San Juan Mountains. The formation thins from west to east, and Burroughs (1980) implies that the layer is about 15 meters (50 feet) thick at the Mapco-Amoco site. The formation is significant in the Monte Vista graben and should be the main reservoir rock for geothermal water in that graben.

d. Vallejo Formation

The Vallejo Formation is composed of fine-grained, unconsolidated but compact silt and clay with thin lenses of cemented sand and fine gravel, and thick layers of coarse gravel containing rounded cobbles (Burroughs, 1980). Burroughs (1980) reported encountering the Vallejo at about 1490 meters (4900 feet) in the Mapco-Amoco well. The formation then persisted to the limit of logging at 2438 meters (8000 feet). Varying depths were encountered at other sites in the basin. This formation should be the main source for geothermal water in the Baca graben.

e. Volcanic and Volcaniclastic Rock

It appears that volcanics and volcaniclastics underlie the Vallejo in parts and cover the Precambrian basement of the basin to varying depths. The information is sketchy, though, and other than noting its existence, little more can be said.

3.1.2 Heat Source

The Rio Grande rift has been shown to be a zone of high heat flow. However, the rift contains relatively few geothermal springs. This lack of springs suggests undiscovered sources of geothermal water that lack surface expression. The rift is both tectonically and volcanically active. Heat flow, seismic, geochemical, and gravity studies suggest the presence of shallow magma bodies along the rift. Measurements have shown heat flows greater than 2.5 HFU along the rift as compared to a global average of 1.5 HFU ($1 \text{ HFU} = 1 \times 10^6 \text{ cal/cm}^2/\text{S}$), the average being $2.56 \pm 0.65 \text{ HFU}$. The $\pm 0.65 \text{ HFU}$ variation in heat flow suggests the occurrence of convective groundwater movement. Figure 3-5 is a heat-flow map of northern New Mexico and southern Colorado.

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(units = Heat Flow Units - HFU)

Heat Flow Map of Southern Colorado and New Mexico

FIGURE
3-5

3.1.3 Bottom Hole Temperatures

A bottom hole temperature (BHT) curve for the basin constructed from information from eight wells in the area is provided by Figure 3-6. The eight wells are as follows:

- a. Mapco-Amoco 1-32 State
- b. Carr 1 Crow
- c. Amerada 1-F State
- d. Snowden 1 Killan
- e. Tucker 1 Thomas
- f. Tennessee Gas 1-B State
- g. Carr 1 Kennedy-Williams
- h. Reserve 1-33 NBH Alamosa

Their locations relative to surface features are shown in Figure 3-7. A cross sectional view of the basin showing the relative depth of the wells is provided by Figure 3-8.

The curve of Figure 3-6 was constructed for the most part from old logs and must be considered suspect. Nevertheless, the data indicates a BHT of about 150°C (302°F) at 3050 meters (10,000 feet) in the Baca graben. The data for the Monte Vista graben (Well #6) indicates about 120°C (250°F) at this depth (the basement of the graben). Since the basement of the Baca graben extends to 5790 meters (19,000 feet) at its deepest, it would seem that temperatures greater than 150°C (302°F) might be realized at depth greater than 3050 meters (10,000 feet) in those areas where it is possible to drill to greater depths. For example, it would seem, based on the evidence available at this time, that a well to the east of the Mapco-Amoco well drilled around 3350 meters (about 11,000 feet) might have bottom hole temperatures in excess of 150°C (302°F) as shown in the shaded area of Figure 3-6. However, this is speculative and can only be verified by drilling and testing.

3.1.4 Resource Quality

Very little information is available on the quality of the water in the deeper zones of the confined aquifer of the basin. The best information currently available is from the Mapco-Amoco well in the Baca graben. Analysis of samples taken between 1615 and 1674 meters (5304 and 5491 feet) -- probably in the Vallejo Formation -- indicates a resource with 4000 milligrams per liter (4000 ppm) of total dissolved solids and chlorine concentrations of 2200-3500 milligrams per liter (2200-3500 ppm). Since the recharge of this aquifer is from the east (Sangre de Cristo Mountains) the quality of water should increase to the east.

Geothermal Gradient of San Luis Basin

**FIGURE
3-6**

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Relative Location of Wells in the San Luis Valley

FIGURE
3-7

Cross Section of Alamosa Basin Showing the Relative Locations of Wells

**FIGURE
3-8**

3.1.5 Reservoir Confirmation Plan

The primary purpose of a reservoir confirmation plan is to establish the suitability of the geothermal reservoir in question, here the San Luis Valley of Colorado, in terms of minimum acceptable values for reservoir productivity and temperature. The most efficient and economical path toward this confirmation of reservoir suitability will involve analyzing all presently available data, determining where the major gaps are in the available data, and generating sufficient new data to bridge those gaps.

Only one deep well drilled within the San Luis Valley is considered to have reliable temperature data, the Mapco-Amoco deep oil exploration well. This well is represented to have a bottom hole temperature of 128°C (262°F) and a temperature gradient of about 38.8°C/km ($3.1^{\circ}\text{F/100 feet}$). Even this data is somewhat suspect since the well was not drilled as a geothermal exploration well so that the temperature profile of the well was not a primary concern to the driller. Several other deep wells and many shallow water wells exist in the valley with no associated good quantitative, descriptive temperature data. Since temperature is one of the critical parameters that will determine the success or failure of the geothermal project, it is recommended that available thermal wells, especially the deep wells, be surveyed for temperature so that a reliable temperature gradient map can be generated covering the area of interest. This data can then be extrapolated so that the depth at which successful geothermal temperatures will be encountered can be more accurately determined. This data in turn will be used to design the casing weights, setting depths and the drilling program that will be used in a deep exploratory well.

After the available thermal wells have been surveyed, consideration can be given to drilling several slim, temperature gradient holes to depths of up to 900 meters (3000 feet). Data from these thermal gradient holes will be used to fill gaps in the thermal data for areas of interest so that the thermal regime of these areas can be more accurately determined.

Surface gravity data has been generated in the San Luis Valley since the early- to mid-1960s. This early gravity data has been incorporated on a regional map by Behrendt and Bajwa in 1974. This data, along with data currently being generated in a detailed gravity survey by the Colorado School of Mines for the San Luis Valley can be used to describe and model the area subsurface geology. This will help identify subsurface faults and other structural features so that potentially successful drilling sites can be targeted.

It is then recommended that an electrical resistivity survey be run at the surface over the areas of interest. Geothermal reservoirs exhibit characteristics in a resistivity survey that can be identified. This type of survey can give a good idea as to the vertical location and horizontal extent of possible geothermal reservoirs.

Active reflective seismic surveys have been conducted in the northern and southern portions of the San Luis Valley by the Colorado Department of Natural Resources, Division of Water Resources, and the USGS, Water Resources Division. A review of this data can detail the location and orientation of subsurface faults. Some thought should be given to running active seismic surveys in targeted drillsite areas that are not covered by previously published data.

Analysis of temperature, surface gravity, resistivity, and seismic data will form the basis for drillsite selection. Once the drillsite with the most likelihood for success has been chosen, final well design can be completed based on the expected reservoir parameters and expected reservoir location.

At this point, the details of the well test plan should be finalized. Well testing can be divided into two phases: testing performed during the drilling of the well; and production testing, which occurs after drilling operations are complete. Well tests that will occur during drilling include mud logging, coring, electrical well logging, temperature buildup surveys, and drill stem testing.

The testing program designed for the well should include mud logging. Continuous mud logging defines the lithology of underground formations as they are being drilled through. This is done by taking samples of the drilled cuttings and tagging them for analysis, monitoring any gas shows as the drilling progresses, and monitoring the condition of the drilling mud to insure that drilling is progressing in the most efficient and cost-effective manner possible.

Mud logging also serves as a primary safety tool when drilling geothermal wells. As drilling progresses and high temperature/pressure resources are encountered, the only containment for these potentially dangerous resources is the hydrostatic pressure exerted on the formation by the tall, heavy column of drilling mud in the drilled hole. If a subsurface void is encountered while drilling, the column of mud can rush out into the formation, leaving subsurface reservoirs uncontained. Any time delay in detecting this situation can result in an uncontrolled well blowout with adverse consequences for any men or machinery in the vicinity of the well. Good mud logging will detect this situation before it gets out of control so remedial action can be taken.

Mud logging also provides a thorough and complete record of actions taken by various parties involved during the drilling of the well. This record can provide

invaluable information and clues as to the nature of the underground formations during the well testing and test analysis that will follow.

Before each string of well casing is set and cemented in the hole a set of open-hole electrical well logs should be obtained. There are several types of electrical well logs: inductive, resistive, sonic, and nuclear. Each of these logs attempts to define the underground environment to determine permeability, porosity, presence of fluid, type of fluid, type of formation (shale, clay, etc.), vertical thickness and location of each formation bed, and possible horizontal extent of each formation. Several different types of downwell electrical logs are run because each type has performance limitations which, if unrecognized, would lead to a false characterization of the down-hole environment. The running of several logs by an experienced logging contractor allows for a much more accurate interpretation of the information generated by these logs.

The selection of which electrical logs will be run on the well will be dependent upon what formations are encountered during drilling as some logs do not perform well in certain formations. Since this is an exploratory situation, it is recommended that a complete suite of well logs be run. Logs that may seem to be redundant or of little value now might prove to be critical later during the interpretation of reservoir characteristics. At that time, after the well is cased, it will be too late to run any valuable logs that were omitted earlier. The selection of which logs to include in the suite must be based first on the maximization of useful information and second on minimum cost in this exploratory situation.

Several core sampling points should be programmed into the drilling program. The depths at which core samples will be taken will be based on the location of various subsurface geologic formations. Coring is very useful in that it gives the opportunity to see what the formation currently being drilled actually looks like. When drilling is progressing several kilometers below surface, the information obtained from a core sample is very valuable especially with regard to the correlation and analysis of electrical well logs.

At several key points during drilling, temperature buildup surveys (12 hour minimum) should be run. A temperature buildup survey consists basically of halting the circulation of drilling fluids in the hole and observing the rise in temperature that occurs downhole. When drilling fluids are being circulated in the hole, they act as a cooling media and hence the rise in temperature that occurs when circulation stops. Data obtained during the temperature buildup survey is extrapolated over time to

derive a stabilized temperature profile for the well. This temperature profile in turn is extrapolated over depth to determine if the target temperature will be encountered within the preprogrammed well depth. If the target temperature will be missed, then consideration will have to be given to either drilling deeper or abandoning the well and redrilling in a different location.

When an apparently productive region is encountered, it may be desirable to confirm the suspected productivity of the formation by running a drill stem test before expensive casing is installed in the well. This is a decision that is made in the field by the well owner.

During a drill stem test, the well is completed in a temporary fashion with small diameter tubing and an expandable packing device that seals the annulus between the tubing and the wellbore. At the bottom of the small diameter tubing is a drill stem test tool consisting of: various temperature and pressure sensors, a slotted section of tubing through which fluid can be admitted to the small diameter tubing string, and a fluid shutoff valve that can be opened and closed from the surface.

To run the drill stem test, the drill stem test tool is lowered into the hole, the fluid flow valve is closed, and the expandable packing device is activated. Downwell pressure is monitored throughout the duration of the test. The fluid flow valve is then opened and the well is produced through the tubing to the surface. If the well will not flow on its own, as is often the case, a subcontractor is brought in to artificially lift the column of water in the wellbore by introducing gaseous nitrogen through tubing set in the test tubing in the well.

The well is allowed to flow for a set length of time, typically about 2 hours, and then shut in with the fluid flow valve. After a short period of shut-in (about 1 hour), the well is allowed to flow again for a second interval, perhaps 10 hours in duration. At the end of this flow period, the well is again shut in.

During this test period, the downwell pressure falls during periods of well production and climbs during periods of well shut-in. By comparing the well production information with downhole pressure data, the producibility/injectivity of the region being tested can be calculated approximately.

There are several problems associated with running drill stem tests. If the test is run on an open hole, and if the formation is unconsolidated, then the formation may cave in around the drill stem test tool when the well is produced. Sticking a drill stem test tool in the hole can result in costly removal or a complete loss of the well if the tool cannot be retrieved. Also, the test must be carefully run and the data properly

interpreted by an expert or the derived production index of the well will be wrong. In some cases an intermediate casing string is already cemented in place to a point just above the region to be tested. This allows the expandable packer assembly to be set in existing casing so that well caving around the drill stem test tool is not a problem.

This will conclude the phase of testing completed prior to the completion of the well. At this time the production testing phase of the well test program begins. The production testing phase can be divided into two separate tests, the initial cleanout or pit test and a long-term (30 day) production test.

The initial cleanout test involves producing the well into the drill cuttings pit. The duration of the test depends upon the volume of the cuttings pit, but generally runs around 12 hours. The primary purpose of this test, as the name indicates, is to clean residual drilling mud, drill cuttings and debris from the wellbore and producing formation. It is essential that this cleanout take place soon after the well has been completed as otherwise irreparable formation damage could result. It is often necessary to have a nitrogen (or air) pump truck onsite to bring in the well by artificial gas lift as reservoir pressure may not be sufficient to overcome the fluid pressure head generated by the column of heavy fluid remaining in the hole. During the well cleanout operation, preliminary data can be obtained on well productivity and temperature. However, this flow period is not long enough to accurately characterize the well.

After completion of the initial well cleanout operation, preparations can be made for the long-term production test. The most important consideration involved in planning a 30-day production test concerns the question of fluid disposal. In the San Luis Valley, the only acceptable method of fluid disposal will involve injection back into the subsurface reservoir. Therefore, a suitable injection well will have to be drilled and completed before a long-term production test can be run.

When a suitable injection well has been completed and surface piping between the wells and an injection pump have been installed, the production test can be run.

Prior to the start of the test the static well pressure should be monitored for several days (or until the pressure has stabilized). Then geothermal fluid will be produced and injected for a 30-day test period. During this test period, the following data shall be recorded:

- a) Surface temperature - production well
- b) Surface temperature - injection well
- c) Surface pressure - production well

- d) Surface pressure - injection well
- e) Fluid flow rate
- f) Motor amps drawn by injection and/or production pumps
- g) Subsurface operating pressure

This data will be analyzed so that the well(s) can be completely characterized and production and injection indices derived.

In addition, periodic samples of produced geothermal fluid shall be taken, checked for sand content and analyzed chemically so that any materials selection problems or pollution control problems (H_2S gas production, etc.), can be identified and mitigated.

3.2 FEEDSTOCKS

The San Luis Valley is located in all or part of nine counties: Alamosa, Archuleta, Conejos, Costilla, Hindsdale, Mineral, Saguache and San Juan. Average annual rainfall is approximately 17.7 centimeters (7 inches), with the temperature ranging from $-40^{\circ}C$ ($-40^{\circ}F$) to around plus $32^{\circ}C$ ($90^{\circ}F$). The valley is considered to be a high mountain desert with cool summers and cold winters. The combination of high altitude and low temperatures makes the growing season very short (see Table 3-1).

Table 3-1

GROWING SEASON PROFILE FOR THE SAN LUIS VALLEY, COLORADO

	Growing Season (Days)	Annual Mean Temperature		Average Annual Precipitation	
		$^{\circ}C$	$(^{\circ}F)$	cm	(Inches)
Alamosa	98	5.3	(41.6)	17.6	(6.94)
Center	96	5.4	(41.8)	18.7	(7.37)
Del Norte	114	6.1	(43.1)	23.9	(9.41)
Hermit Station	11	1.4	(34.6)	40.1	(15.80)
Manassa	90	5.7	(42.3)	18.7	(7.38)
Monte Vista	72	5.3	(41.6)	18.4	(7.25)
Saguache	106	6.1	(43.1)	21.5	(8.49)

Potatoes are the most important cultivated crop, surpassing the combined value of all other cultivated crops. Barley and wheat are also important grain crops, with barley in demand as a malting product.

Crop production for 1979 -- latest published data -- in the San Luis Valley is listed by county in Table 3-2. These production figures are typical for the last few years. The annual feedstock requirements for a 76-189 million liter (20-50 million gallon) plant, assuming a 50 percent mix of potatoes and grain, is provided below. The figures assume the grain to be a 40/60 mix of wheat and barley. The ethanol yields for potatoes, barley and wheat used are 0.117 liter/kilogram (1.4 gallon/CWT), 220 liter/cubic meter (2.05 gallon/bushel), and 269 liter/cubic meter (2.5 gallon/bushel), respectively.

Table 3-2

SAN LUIS VALLEY CROP PRODUCTION

Alamosa (1), Conejos (2), Costilla (3), Mineral (4), Rio Grande (5),
Saguache (6)

Barley: 209,277 Metric Tons (9,099,000 Bushels)*

	<u>Metric Tons</u>	<u>(Bushels)</u>
(1)	29,808	(1,296,000)
(2)	32,200	(1,400,000)
(3)	17,986	(782,000)
(4)	-0-	-0-
(5)	78,775	(3,425,000)
(6)	<u>50,508</u>	<u>(2,196,000)</u>
	209,277	(9,099,000)

Wheat: 51,702 Metric Tons (1,951,000 Bushels)**

	<u>Metric Tons</u>	<u>(Bushels)</u>
(1)	2,862	(108,000)
(2)	2,756	(104,000)
(3)	10,600	(400,000)
(4)	-0-	-0-
(5)	13,595	(513,000)
(6)	<u>21,889</u>	<u>(826,000)</u>
	51,702	(1,951,000)

* Assumes 653 kg/cubic meter (51-52 pounds/bushel).

** Assumes 748 kg/cubic meter (58-59 pounds/bushel).

Table 3-2 (Continued)

Potatoes: 519,162 Metric Tons (572,750 Tons)

	<u>Metric Tons</u>	<u>Short Tons</u>	<u>CWT</u>
(1)	75,730	83,850	1,677,000
(2)	24,897	27,450	549,000
(3)	20,952	23,100	462,000
(4)	-0-	-0-	-0-
(5)	310,738	342,600	6,852,000
(6)	86,845	95,750	1,915,000
	<u>519,162</u>	<u>572,750</u>	<u>11,454,000</u>

Ethanol Production Feedstock	<u>(Millions of Liters)</u>		<u>(Millions of Gallons)</u>		
	<u>76</u>	<u>189</u>	<u>20</u>	<u>50</u>	
	<u>Metric Tons</u>		<u>Bushels/CWT</u>		
Potatoes (50%)	323,930	809,820	7,142,900	17,857,000	CWT
Wheat (20%)	47,059	117,650	1,600,000	4,000,000	bu
Barley (30%)	75,758	189,390	2,926,800	7,317,100	bu

These figures indicate that if all of the wheat, 62 percent of the potatoes, and 36 percent of the barley crop were available for ethanol production, the valley could support a 76-million liter (20 million gallon) plant. However, a 189 million liter (50 million gallon) facility would require importing feedstocks even if the entire annual crop of the valley were committed. It must be recognized, however, that such a commitment is not possible and feedstocks will have to be imported.

3.3 ACQUISITION AND DISTRIBUTION OF FEEDSTOCK AND PRODUCTS

Locally grown potatoes, barley and wheat combined with imported grains are considered the primary feedstocks for the ethanol production facility. The acquisition of these feedstocks in the quantities necessary to sustain plant operation will require continuous coordination in the realms of feedstock availability, storage facilities and shipping methods. Additional areas of concern also include distillers dried grains (DDG) marketing and shipping.

3.3.1 Feedstocks

Feedstock procurement is influenced primarily by seasonal variations in crop production, which has a direct effect upon existing storage facility's supplies. Shipment of feedstock by either rail or truck is controlled by monetary considerations, and occasionally, inclement weather. These three feedstock parameters (availability, storage and shipping) will be discussed relevant to each primary feedstock as follows.

3.3.1.1 Potatoes

The State of Colorado is a potato exporter, producing 609.3 thousand metric tons (13.353 million CWT) of potatoes annually, with 522.7 thousand metric tons (11.455 million CWT) grown in the San Luis Valley, 79.3 thousand metric tons (1.74 million CWT) in Morgan and Weld Counties in northeastern Colorado, and 7.3 thousand metric tons (159,000 CWT) in miscellaneous counties throughout the state. The crop is planted in mid-May and harvested from September to October. In Morgan and Weld Counties, 75 percent of the annual production is shipped out of state to the north, and the remainder consigned to Denver for processing into chips and shoestring potatoes. As such, potato storage facilities north of Denver are almost nonexistent. In the San Luis Valley, 387.9 thousand metric tons (8.5 million CWT) of potatoes are shipped by truck at the time of harvest with the remaining 134.8 thousand metric tons (2.955 million CWT) stored locally.

Existing storage facilities include several sites at up to 45.6 thousand metric tons (1 million CWT) each and newer "storage condominiums." These are collections of storage bins of approximately 1.14 thousand metric tons (25 thousand CWT) each, with individual temperature controls. Potato retention times can vary from 4-5 months in "normal" storage to 8-10 months utilizing environmental controls and sprout inhibitors. Refinement of these techniques is expected to create viable retention times of up to 1 full year, thereby enabling year-round marketing. This would be advantageous for the Colorado potato producers by allowing them to compete with the spring harvests from Texas, California, and Florida. The market price for "old" and "new" potatoes is similar, for, contingent upon end-use, older potatoes are often preferred over newer ones due to ease of processing.

Virtually all of Colorado's intrastate and interstate shipment of potatoes is accomplished by truck, with no significant importation. Only the San Luis Valley potato crop production can be considered as a feedstock source, for interstate transportation costs would make imported potatoes prohibitively expensive for the production of ethanol. Acquisition of potatoes in the San Luis Valley would be governed by supply and demand. While immense quantities are available, competition for inexpensive supplies will be keen, especially from the two ethanol facilities now under construction in the Monte Vista area. However, while these facilities will influence the potato supply situation, their combined size of 11.4 million liters (3 million gallon) is relatively small, and their feedstock demand should not be excessive.

3.3.1.2 Barley

The San Luis Valley's annual barley production of 212,578 metric tons (9.1 million bushels) comprises 90 percent of Colorado's malting barley and 45 percent of all barley grown in the state. Moravian III, Klage and Steptoe malting barleys are grown almost exclusively on a contract basis for the Coors, Pabst and Schlitz breweries. These contracts usually encompass 98 percent of the San Luis Valley barley crop, and are renewed annually before spring planting for delivery of the fall harvest. While this situation appears equitable to both producers and consumers, it often creates a surplus of barley with no purchasers. This is caused by the necessity to rotate crops to ensure that soil nutrient depletion does not become a problem. Due to the unique growing season in the San Luis Valley, barley, oats and wheat are the usual crops rotated. Therefore, when a grower is anticipating planting barley and then fails to renew his contract with the breweries, he is still committed to planting barley. He must then actively seek a purchaser for his crop, and failing that, place it in storage. This situation currently exists, and private barley storage from the 1980 harvest is at an all-time high.

Barley can be stored virtually anywhere clean and dry, so most barley producers maintain their own storage facilities. Barley and most grains can be stored indefinitely, so it is possible for a grower to have supplies in storage from several years previous production. This makes it difficult to ascertain specific quantities of barley in storage. The Agricultural Stabilization and Conservation Service (ASCS) attempted at one time to quantify the on-farm storage capability in the San Luis Valley, but most farmers were reluctant to release such data, and since clean and dry are the only criteria for storage, a simple estimation of grain silo sizes and capacities could not be deemed accurate. The ASCS eventually curtailed its efforts. Therefore, while there exists a current barley surplus, the specific quantities are unknown. As noted above, however, this situation is unusual, and the malting barley crop is not often available to the open market.

There are two methods to ensure that barley can be successfully utilized as a primary feedstock rather than an intermittent supply. One method would be for the ethanol facility to contract with the growers as the breweries do, but on a continuous basis for inferior grades of barley that are less energy intensive to grow and therefore less expensive. This would encourage producers to grow the "ethanol barley" at less expense for a reduced selling price to a continuous, stable market at about the same profit rate. As the malting barley possesses attributes which are superfluous

when utilized in the production of ethanol, the growing of inferior barleys would benefit both producers and consumers. The second method of obtaining barley supplies would be importation from the northeast, east central, and southwest areas of Colorado. These regions in 1979-1980 produced 140,161, 39,712 and 53,729 metric tons (6.0, 1.7, and 2.3 million bushels) respectively, most of which was of the non-malting variety. While utilizing these crops would ensure the lowest possible purchase price, transportation costs by rail or truck are an important consideration, and are discussed in Section 3.3.2.

3.3.1.3 Wheat

There are two wheat harvests in the State of Colorado. Spring wheat is planted in late March and harvested in mid-September, and winter wheat is planted from September to November and harvested beginning in July. The San Luis Valley 1979 spring wheat production of 51,744 metric tons (1.95 million bushels) was 76 percent of Colorado's total spring wheat crop. The winter wheat crop of 1,793,795 metric tons (67.6 million bushels) is grown primarily within the east central, northeast and southeast sectors of the state, with the San Luis Valley's contribution being miniscule due to the severe winters. Both the spring and winter wheat crops are suitable for ethanol production.

In order to utilize wheat as a primary feedstock, the eventual destination and end use of the spring and winter harvest must be known to determine if it can be diverted from the current consumers. The Colorado Grain Flow Patterns Study, 1980, published by Colorado State University at Fort Collins, investigates the destinations of Colorado's primary grains (wheat, corn and sorghum). Wheat is similar to barley, however, in that it can be stored indefinitely. This means that the wheat in storage and transit can be a collection of several years harvest of both spring and winter wheat. As such, all destinations and end uses are discussed in terms of percentages of total wheat shipped from commercial storage facilities in Colorado. This information is shown in Table 3-3.

Table 3-3

**DESTINATION AND END USE OF COLORADO'S
1980 WHEAT SHIPMENTS**

<u>Destination</u>	<u>Percent of Total Shipments</u>	<u>End Use</u>
Northwest Coast	37.5	Export Out of Country
Gulf Coast	22.0	Export Out of Country
Kansas City	10.2	Milling, Local Export, Misc.
Denver	9.1	Milling, Local Export, Misc.
Nebraska & Missouri	7.8	Milling, Local Export, Misc.
California Coast	6.1	Milling
Utah	3.6	Milling
Other	3.7	Misc.

The two largest markets for Colorado's wheat in 1980 were the West Coast at 43.6 percent and the Gulf Coast at 22 percent. All but small quantities of these shipments were further exported out of the country. It is this export market from which wheat could probably be diverted most easily, primarily due to the quantities (59.5 percent of total shipments) involved.

3.3.2 Grain Storage and Transportation

The commercial facilities for storage of barley, wheat and other grain types in eastern Colorado are quite extensive, as illustrated in Figure 3-9. This map indicates the major highways and rail lines in Colorado and commercial storage facilities with capacities in cubic meters. These facilities would be the locations for grain storage prior to shipping to the San Luis Valley from the north, northeast, east central, and southwest areas of Colorado.

The transportation of these grains to the San Luis Valley would be accomplished by rail or truck. Almost all of the storage facilities are located adjacent to rail lines and highways, thereby providing two shipping methods. The selection of the transportation method will be contingent upon cost, delivery time and reliability. However, the factor that will most affect the delivered feedstock price will be the original production source. Table 3-4 indicates the annual wheat production, commercial grain storage facilities, and the truck and rail shipping costs from the facilities for each wheat growing district in Colorado.

With a 1979 average wheat market price of \$91.77 per cubic meter (\$3.13 per bushel), the requisite shipping charges can amount to from 11.3 percent to

Table 3-4

**ANNUAL WHEAT PRODUCTION, COMMERCIAL GRAIN STORAGE, AND SHIPPING COSTS
TO ALAMOSA BY WHEAT GROWING DISTRICT**

Wheat Growing District	Wheat Production Per Year ¹		Grain Storage Capacity ²		Shipping Cost in \$ ³			
	Metric Tons	Thousands of Bushels	Cubic Meters	Thousands of Bushels	Per Kg		Per CWT	
					Rail	Truck	Rail	Truck
Northwest ⁴ and Mountain	35,557	1,340	—	—	.034	.039	1.56	1.780
Northeast	390,628	14,721	751,470	21,183	.020	.024	.896	1.110
East Central	1,077,365	40,601	895,819	25,252	.019	.019	.851	.880
Southwest ⁵	33,116	1,248	—	—	.035	.017	1.60	.780
San Luis Valley	51,771	1,951	—	—	-0-	-0-	-0-	-0-
Southeast	273,899	10,322	271,066	7,461	.015	.017	.682	.780

¹Includes spring and winter wheat crops, from 1980 Colorado Agriculture statistics.

²Obtained from 1980-1981 Mountain States Grain and Feed Directory.

³Rail Costs were obtained from the Denver and Rio Grande Western Railroad Company and are a composite for each district. Truck shipping costs were obtained from the Public Utilities Commission of the State of Colorado and are based upon a central location for each district.

⁴Primarily Moffat, Routt, and Rio Blanco Counties.

⁵Primarily Dolores, Montrose, and Montezuma Counties.

25 percent of the delivered price (excluding the San Luis Valley). Table 3-4 also reveals that the east central district produces the largest annual wheat crop and maintains the most storage capability, with shipping charges to Alamosa accounting for about 14 percent of the delivered feedstock price. Conversely, the San Luis Valley is one of the smallest wheat producers, but shipping costs would be essentially zero. It would therefore be advantageous to establish a district priority system in order to provide the quantities of feedstock required at the least possible expense. This illustrates the fact that in order to minimize feedstock procurement costs, a priority system establishing which district to purchase from first should be established.

3.3.3 Distillers Dried Grains

Distillers Dried Grains (DDG) are the primary fermentation residues from the production of ethanol. A 76 million liter (20 M gallon) per year ethanol facility will produce 69.7 million kilograms (76,800 tons) of DDG annually. DDG is composed of dealcoholized whole stillage with the starch removed from the virgin feedstock. It contains an approximate three-fold concentration of all remaining nutrients along with yeast cells, metabolites, and Grain Fermentation Factors (GFF). GFF are as yet unidentified nutrients which stimulate growth and rumen digestion, although it is speculated that these substances are formed by yeast cells during the fermentation process. These yeast cells make up 6-12 percent of the DDG. The combination of a three-fold increase in nutrients along with the Grain Fermentation Factors create a product particularly well suited for use by feedlots and feed manufacturers. Experiments as reported by the Distillers Feed Research Council have shown that the distillers dried grains are suitable for use as a feed additive in concentrations varying from 5 to 50 percent for cattle, poultry, sheep, swine and dogs.

The intrastate feedlot market is considered to be the most viable for sale of the distillers dried grains. Rail shipping costs from Alamosa to Denver are \$0.015 per kilogram (\$0.680 per CWT). With a current market value of \$0.171 per kilogram (\$7.75 per CWT) delivered, this would leave a net value of \$0.156 per kilogram (\$7.07 per CWT). The interstate and export markets are also possible opportunities. However, the Denver and Rio Grande Railway's preliminary estimate of \$0.148 per kilogram (\$6.71 per CWT) for shipping charges from the San Luis Valley to the nearest commodity exchange handling DDG in Chicago would make this unattractive. Exporting to foreign countries would incur similar transportation costs plus be susceptible to import tariff charges. Based upon these considerations, it appears that domestic markets should be thoroughly investigated before contemplating interstate and foreign shipments.

The rail line charges are based upon a minimum weight of 81,653 kilograms (180,000 pounds) in covered hoppers. A distillers dried grain production of 69,350 metric tons (76,800 tons) annually will create DDG at the rate of 190,930 kilograms (421,000 pounds) daily. If shipments of DDG are made weekly, this will require a storage capacity of 0.95 million kilograms (2.1 million pounds). This might be accomplished by utilizing local on-farm storage as is presently done with barley and wheat. If further investigations indicate this is not a viable solution, it may be necessary to maintain storage facilities onsite. This would incur additional initial purchase and construction costs, but once erected, the storage structures would assure a continuous, adequate, known quality of storage.

A possible solution to the quandries of both shipping and storage of distillers dried grains would be the development of a local market consisting of feedlots, ranchers, and anyone raising animals as a business venture. The Colorado State inventory of 3 million cattle and calves consume approximately 8.16 to 10.89 million kilograms (18 to 24 million pounds) of feed daily, or 2.98 to 3.97 million metric tons (3.26 to 4.38 million short tons) annually. If DDGS were used to replace 20 percent of these feeds, 596,000 to 794,000 metric tons (657,000 to 876,000 short tons) would be required. This is about 10 times the DDG production for a 76 million liters (20 M gal) per year ethanol plant. Therefore, if only 10 percent of the potential cattle and calf market is developed, the disposal of DDG would be realized as economic benefit to the ethanol plant.

3.4 WATER

A review of available reports and conversations with the Colorado District water engineer indicates (McFadden, 1981) that the availability of water in the San Luis Valley is limited and could be a significant problem for the construction, operation and maintenance of the plant. A recent memo by the state water engineer has imposed a ban on the drilling of new water wells for consumptive use in the closed basin of the valley. Under the ban additional water is not available for any consumptive use, which would include wet cooling towers if required for plant process, and makeup requirements. Water rights may be purchased from "Senior Rights" providing they are available for sale. But it must be proved that there would be no damage caused to holders of "Junior Rights." Acquisition of water is on a site-specific basis and must be reviewed by the state for approval.

3.4.1 Basin Description

"The total water supply entering the valley averages about 3.1 cubic kilometers (2.5 million ac-ft) per year. About 1.87 cubic kilometers (1.5 million ac-ft) is stream-flow derived from snowmelt in the surrounding mountains. The other 1.23 cubic kilometers (1 million ac-ft) comes from the 18 centimeters (7 in) of precipitation which falls on the valley floor.

Of the 3.1 cubic kilometers (2.5 million acre-feet) of water that reaches the valley, about 0.63 cubic kilometers (0.5 million acre-feet) is owed to New Mexico under compact. Another 1.23 cubic kilometers (1 million acre-feet) evaporates, leaving about 1.23 cubic kilometers (1 million acre-feet) annually for irrigating crops.

The soil conservation service has estimated that 2.46 cubic kilometers (2 million acre-feet) of water is needed each year to obtain maximum production from land presently under irrigation. Despite the 3.1 cubic kilometers (2.5 million acre-feet) the valley receives each year, severe water shortages occur after the snowmelt season during the latter part of July, August and September (USDA 1978)."

3.4.2 Plant Water Operating Requirements

3.4.2.1 Summary

An overall water balance study has been performed for the proposed alcohol facility to determine whether a non-consumptive water use requirement can be satisfied by the plant as it is presently designed utilizing available feedstocks. The results of the water balance study show that the nonconsumptive use of water requirement can indeed be met if the proper mix of feedstocks is utilized during the plant operating year. When the alcohol plant is using potatoes as a feedstock, the plant is actually a net water producer producing a quantity of recoverable water equal to approximately three times the plant makeup water requirement. This is shown graphically in Figure 3-10, the plant water balance for the San Luis Valley ethanol plant when operating on potatoes as a feedstock. When the plant is operating on a grain feedstock such as wheat or barley, recoverable water from plant process streams will satisfy about 80 percent of the plant makeup water requirements. This is shown in Figure 3-11, the water balance for the plant when operating on a grain feedstock. The alcohol plant will therefore be a net consumer of water when operating on a grain feedstock.

In order for the plant to satisfy the no net water consumption requirement, the plant will have to use high water content feedstocks (potatoes) to compensate for the comparatively low water content of the grain feedstocks. Ideally, 12 percent or

WATER BALANCE FOR SAN LUIS VALLEY GEOTHERMAL ALCOHOL PLANT WHEN OPERATING ON POTATO FEEDSTOCK

FIGURE 3-10

**WATER BALANCE FOR SAN LUIS VALLEY GEOTHERMAL ALCOHOL PLANT WHEN
OPERATING ON GRAIN FEEDSTOCKS**

**FIGURE
3-11**

more ethanol production from high water content feedstocks (potatoes) will make the plant a net water producer.

Thus, the critical question of plant water consumption is dependent upon the availability of high water content feedstocks (potatoes) for the alcohol plant.

3.4.2.2 Plant Water Consumption - Potato Feedstock

The following numbers for plant water consumption are for illustrative purposes only and were generated by using a 76 million liter/year (20 million gallon/year) alcohol plant as a basis. The actual quantities of water required for plant operation will be dependent on the actual size of the alcohol plant. Relative percentages for the different plant input and outputs will remain the same independent of final plant size.

The largest water input required by the plant when it is operating on potato feedstocks is the makeup water supplied to the potato flume. The quantity required is 15,800 kilograms/hour (34,700 pounds/hour) of water which is equal to 63 percent of the total plant water requirement.

The other significant water input required by the plant is the 8300 kilograms/hour (18,300 pounds/hour) of geothermal steam that is injected directly into the plant process stream in the jet cookers. This is about 33 percent of the total plant water requirement.

The remaining 4 percent of the total plant water requirement is made up of minor streams added during pH adjustment phases of alcohol production and makeup water requirements supplied to the CO₂ gas scrubber and the fusel oil washer.

This results in a total plant water requirement of 25,000 kilograms/hour (55,000 pounds/hour) for a 76 million liter/year (20 million gallons/year) alcohol plant.

On the output side of the process stream, water is removed from the process at several points. In the silt settling pond, 15,000 kilograms/hour (32,900 pounds/hour) of water is lost to silt and evaporation from the pond. The rotary steam tube by-product dryers lose 12,000 kilograms/hour (26,800 pounds/hour) of water to the atmosphere. Smaller quantities of water are lost from the CO₂ gas scrubber, the flash cooling tank, and directly to the by-product in the form of moisture contained within the distillers dried grains (DDG). It is not technically or economically feasible to recover these lost streams of water at the present time.

However, several sources of recoverable, recyclable water do exist within the plant. The centrifuge that dewateres the mashed potatoes, the centrifuge that dewateres the whole stillage from the beer still and the hydrocarbon stripping column

are all good sources of water supplying 32,100 kilograms/hour (70,700 pounds/hour), 38,900 kilograms/hour (85,600 pounds/hour), and 1000 kilograms/hour (2300 pounds/hour) respectively of recyclable water.

This results in 72,000 kilograms/hour (158,600 pounds/hour) of water that can be treated and re-used within the plant. Since total plant make-up water demand is only 25,000 kilograms/hour (55,000 pounds/hour), a substantial surplus quantity of water is available when the plant is operating on potatoes.

3.4.2.3 Plant Water Consumption-Grain Feedstock

When the alcohol plant is operating with a grain feedstock, such as barley, corn or wheat, the plant consumes more water than is available for recovery. This result is caused primarily by the lower water content of the input feedstock.

Makeup water requirements include 49,500 kilograms/hour (108,900 pounds/hour) of water required for grain slurry make-up and 5000 kilograms/hour (11,100 pounds/hour) of geothermal steam input directly into the process stream in the jet cookers. These two flow streams taken together account for 99 percent of the plant water requirement when the plant is operating on grain feedstocks. The remaining 1 percent of water demand includes water added during pH adjustment of the slurry and makeup water required by the CO₂ gas scrubber and the fusel oil washer. The total plant water demand is 55,000 kilograms/hour (121,200 pounds/hour).

Water is lost from the process stream primarily from the by-product dryers where 10,600 kilograms/hour (23,400 pounds/hour) is vented to the atmosphere. Smaller sources of loss include the 90 kilograms/hour (200 pounds/hour) vented from the CO₂ gas scrubber and 860 kilograms/hour (1900 pounds/hour) that leaves the plant in the form of moisture retained within the by-product, distillers dried grains (DDG). These streams of lost water are not recoverable at the present time due to technical and economic barriers that prevent such recovery.

Significant sources of recoverable process water include; 42,500 kilograms/hour (93,400 pounds/hour) discharged to the facility waste water treatment plant during by-product processing, 1200 kilograms/hour (2700 pounds/hour) discharged from the flash cooling tanks, and 1000 kilograms/hour (2300 pounds/hour) recoverable from the hydrocarbon stripping column bottoms.

This results in a total quantity of water available for reuse of 44,700 kilograms/hour (98,400 pounds/hour) or 81 percent of the total plant water demand of 55,000 kilograms/hour (121,200 pounds/hour). The remaining 19 percent of the total water demand will have to be obtained from sources outside the plant when the plant is

operating on grain feedstocks. This will be offset by the water generated by the plant during periods when the plant is using potatoes for a feedstock.

3.5 ENVIRONMENTAL ANALYSIS

3.5.1 Introduction

The Environmental Analysis section of this study focuses primarily on environmental parameters, such as air and water quality, which may affect the design of an ethanol plant utilizing geothermal energy. Information obtained through a review of the published literature and existing data comprises the basis for this section. This discussion is not intended to function as either an Environmental Assessment or an Environmental Impact Statement. Such site-specific documents are beyond the scope of this feasibility study.

Environmental characteristics of the San Luis Valley are described, including physical characteristics; climate; air quality; hydrology and water quality; biological, cultural and visual resources; and socioeconomic characteristics. Anticipated effects of the proposed ethanol facility on the environment and possible mitigation measures also are described. Impacts on resources which are highly site-specific such as cultural and biological resources cannot be evaluated until a plant location is selected.

3.5.2 Description of the Environment

3.5.2.1 Physical Features

The San Luis Valley, Colorado, located in the south-central area of the state, is bounded on the west by the San Juan Mountains, on the east by the Sangre de Cristo Range, on the north by Poncha Pass, and on the south by the Colorado-New Mexico border (see Figure 3-1). The valley lies within Alamosa, Conejos, Costilla, Mineral, Rio Grande and Saguache Counties, which are designated Colorado Planning and Management Region No. 8 by the Colorado Department of Local Affairs. The counties encompass 21,186 square kilometers (8180 square miles).

The valley is approximately 185 kilometers (115 miles) long and 80 kilometers (50 miles) wide. Average elevation of the primarily flat valley floor is 2316 meters (7600 feet) above mean sea level. Blanca Peak, the highest elevation in the surrounding mountain ranges, is 4378 meters (14,363 feet) above mean sea level.

Alluvial fans extend outward from the mountain bases. A stream creates an alluvial fan at the point where it flows from a gorge onto a plain or joins a larger stream, depositing clay, silt, gravel or other similar material. The Rio Grande alluvial

fan, which is separate from the others, has a 40 kilometer (25 mi) radius. Debris deposited by erosion of the surrounding mountains fills the valley depression to a depth of about 3050-5800 meters (10,000 to 19,000 feet). This debris consists of gravel, sand, silt and clay, lava flows and other volcanic debris. The five physiographic areas comprising the San Luis Basin are described in detail in Section 3.1.

3.5.2.2 Climate

The San Luis Valley experiences cold winters, relatively cool summers and low precipitation. The mean annual temperature is 6.4°C (43.6°F). In the summer months the high temperature generally is in the mid-20s (°C) (mid-80s (°F)), with lows of near 4°C (40°F). Strong winds with occasional blowing dust occur in the spring and early summer. July and August are the only months free of frost. The growing season averages 110 days. In the winter, winds are light but low temperatures of -26°C (-15°F) to -34°C (-30°F) are frequent.

Average annual rainfall varies depending on the elevation. On the valley floor, precipitation averages 18-25 centimeters (7 to 10 inches) per year. The foothills area receives an average of 23-36 centimeters (9 to 14 inches) per year. The average rainfall is highest in August. In the summer months, hailstorms are frequent.

3.5.2.3 Air Quality

The U.S. Department of Interior's Final Environmental Statement for the Closed Basin Division of the San Luis Valley Project, issued in 1979, contains information about air quality in the valley. The report describes the valley as a "closed air basin" characterized by inversions, minimal air flow and lack of a southern outlet. The limited air flow results in frequent inversions during which pollutants accumulate.

According to the Air Pollution Control Division of the Colorado Department of Health, particulates constitute the primary air pollutant in the valley. Sources include incineration of solid wastes, vehicle exhaust emissions, fuel combustion from stationary sources, home heating emissions, agricultural burning and forest fires (U.S. Department of Interior, 1979). Fugitive dust is also a factor in the high particulate levels sometimes present in the valley.

Appendix A to this report contains air quality standards set by the State of Colorado as part of its plan for attaining and maintaining the National Ambient Air Quality Standards. Table 3-5 lists particulate measurements for Alamosa obtained by high volume sampling. Note that in 1980 the particulate measurement exceeded federal and state standards for the first time. The Air Pollution Control Division does not monitor gaseous pollutants in the San Luis Valley area.

Table 3-5
PARTICULATE MEASUREMENTS
FOR ALAMOSA*

	<u>Annual Geometric Mean</u>
1975	55
1976	70
1977	67
1978	53
1979	58
1980	76**

*In micrograms/cubic meter ($\mu\text{g}/\text{m}^3$).

**The federal and state primary standard for particulate measurement is $75 \mu\text{g}/\text{m}^3$ (25°C) annual geometric mean.

Although five areas in Colorado are designated "non-attainment areas," Air Quality Control Region 8 (Alamosa, Conejos, Costilla, Mineral, Rio Grande and Saguache Counties) is not so designated at present. After an area, such as the Denver Region, is designated "non-attainment," the Air Pollution Control Division works with the Colorado Department of Highways, local governments and citizens' groups to develop a plan for attaining federal standards.

3.5.2.4 Hydrology and Water Quality

The valley's water supply consists of surface water and groundwater in unconfined and confined aquifers. The area north of the Rio Grande River is known as the "Closed Basin" because there is no hydrologic connection between this basin and the valley area south of the river. Additionally, water in the Closed Basin discharges only by means of evaporation, including transpiration, i.e., loss of water through plant leaf surfaces and consumptive use by plants.

"Non-beneficial" plants consume about one-half of the water used by plants in the San Luis Valley. The term "non-beneficial" refers to plants which have no commercial value. Phreatophytes such as greasewood (Sarcobatus), rabbit brush

(Chyrso thamnus) and saltgrass (Distichlis) are the primary non-beneficial plants located in the valley.

The U.S. Department of Interior, Department of Water and Power Resource Services plans to pump water which would otherwise be consumed through transpiration from the Closed Basin confined aquifer to the Rio Grande. This would help the State of Colorado meet its obligation to deliver water of the required quality and quantity to Texas and New Mexico and enable the U.S. to meet its commitments to Mexico. This plan, entitled "Closed Basin Division, San Luis Valley Project," would also provide water for the proposed Mishak National Wildlife Refuge in Saguache County.

3.5.2.4.1 Surface Water

The valley receives a total annual water supply averaging 3.1 cubic kilometers (2.5 million acre-feet), of which 1.9 cubic kilometers (1.5 million acre-feet) represents stream flow from snow melt in the surrounding mountains. The source of the remainder is precipitation falling on the valley floor.

The quality of surface water in the valley near the mountains is generally excellent. In the center portions of the valley, however, increased dissolved solids concentration is noted (San Luis Valley Electric Coop., Inc., 1980). This increase has an adverse effect on crop yields. An increase in sodium alters soil structure and may cause water logging. While the salt balance is unfavorable in portions of the valley north of Alamosa, in the southern region a more favorable balance exists because the Rio Grande River removes more salt from the soil than it adds.

Data collected by the United States Geological Survey near Lobatos, Colorado indicates good water quality in the Rio Grande near the Colorado-New Mexico border (U.S. Department of Interior, 1979). The following samples were taken in August 1978 below Alamosa:

Total Dissolved Solids (milligrams per liter)	186
Sodium (milligrams per liter)	20
Sodium Percent	29
Sodium Absorption Ratio	0.9

U.S. Environmental Protection Agency (EPA) water quality standards provide that water with total dissolved solids (TDS) concentrations of 500 milligrams per liter (mg/l) or less can be applied to most crops with no detrimental effects. TDS concentrations should not exceed 500 mg/l to comply with secondary standards for drinking water set by the EPA (U.S. Department of Interior, 1979).

The Colorado Water Quality Control Commission held hearings in mid-April 1981 for the purpose of reclassifying all Colorado streams and revising the state water quality standards. The Commission anticipates completing these revisions in the near future. They are not presently available, however.

3.5.2.4.2 Groundwater

The upper unconfined and lower confined aquifers underlying the valley contain approximately 2714 cubic kilometers (2.2 billion acre-feet) of water. Depth of the unconfined aquifer varies from 15-91 meters (50 to 300 feet) below the valley floor. Throughout most of the area, the depth to water in the unconfined basin from the land surface is less than 3.7 meters (12 feet).

Water quality in the unconfined aquifer is excellent in the valley areas nearest the mountains. North of Monte Vista, the nitrogen content is high. The dissolved solids concentration, consisting mainly of salt and sodium ions, increases in the central portion of the valley (San Luis Valley Electric Coop., Inc., 1980).

Discontinuous layers of clay or volcanic rock separate the unconfined aquifer from the lower confined aquifer. Since the confining layer is not continuous, there is some hydrologic connection between the unconfined and confined aquifers. In some locations geologists have differentiated the unconfined and confined aquifers. No area-wide differentiation has been made, however.

Water quality in the confined aquifer generally is superior to that in the unconfined aquifer (San Luis Valley Electric Coop., Inc., 1980). Mineral content is greater in the sump area of the Closed Basin and on the outer edges of the valley. In some areas there is medium to high sodium content. Water in the central portion of the confined aquifer contains gas and has a brown color. The color is associated with a high concentration of fluoride, high salinity, medium to high alkali and the presence of hydrogen sulfide. Analysis of water samples taken from the Mapco-Amoco well (see Figure 3-7) is presented in Section 3.1.4.

3.5.2.5 Biological Resources

The San Luis Valley contains three major federal wildlife management areas: Blanca Wildlife Habitat Area, which the Bureau of Land Management administers, the Alamosa National Wildlife Refuge and Monte Vista National Wildlife Refuge, both managed by the U.S. Fish and Wildlife Service (USFWS). In addition, the Department of Interior plans to establish the Mishak National Wildlife Refuge in conjunction with the Closed Basin Division, San Luis Valley Project.

Four wildlife species which the federal government has classified as endangered may be present in the San Luis Valley:

- Black-footed ferret (Mustela nigripes)
- American peregrine falcon (Falco peregrinus anatum)
- Whooping crane (Grus americana)
- Bald eagle (Haliaeetus leucocephalus)

The black-footed ferret probably only exists in six small areas of Colorado. The species has not been sighted in Region 8 during the period 1974-79. Researchers generally agree, however, that the black-footed ferret population directly depends on prairie dogs. The Bureau of Land Management has identified areas in Region 8 where prairie dog towns are presently located and which have a potential for black-footed ferrets (see Figure 3-12).

The peregrine falcon is known to frequent the San Luis Valley but does not nest there. The Colorado Division of Wildlife emphasizes the importance of maintaining the habitat of prey species within a 16-27 kilometers (10 to 17 miles) radius of nesting areas. A nesting area is located at the junction of Alamosa, Saguache, Huerfano and Custer Counties (U.S. Department of Interior, 1979).

According to USFWS, about 200 to 300 bald eagles winter in the San Luis Valley along the Rio Grande near the Alamosa National Wildlife Refuge. Both the Alamosa and the Monte Vista National Wildlife Refuges are located in the vicinity of the major wintering areas for the bald eagle. These areas characteristically are timbered and located near the Rio Grande.

The USFWS identified the Monte Vista and Alamosa National Wildlife Refuges as critical habitats for whooping cranes (43 Fed. Reg. No. 94, May 15, 1978). In 1975, USFWS established an experimental "foster parent" plan in Idaho. The greater sandhill cranes, which are "foster parents" for the endangered whooping cranes, make a major stopover at the Monte Vista National Wildlife Refuge each spring and fall.

The State of Colorado list of endangered or threatened species includes three species which are presently found in the San Luis Valley or have been present there in the past:

- Greater Sandhill Crane (Grus canadensis tabida) discussed above
- River Otter (Lutra canadensis)
- Rio Grande Cutthroat Trout (Salmo clarki virginalis)

The river otter became extinct in Colorado near the turn of the century, although the species was at one time found in the Rio Grande. Six river otters were

WESTEC Services, Inc.

released into Chessman Lake in the upper part of the South Platte River in 1976. The Chessman Lake area and other areas which the Colorado Division of Wildlife has identified as essential habitat for the river otter are located outside the San Luis Valley (U.S. Department of Interior, 1979).

The upper Rio Grande and its tributaries were the historic range of the Rio Grande cutthroat trout. There are indications, however, that the Rio Grande does not at present contain this species. It requires clear, cold and well-oxygenated streams (U.S. Department of Interior, 1979).

3.5.2.6 Cultural Resources

Although the San Luis Valley is an area of great significance in the history of Colorado and New Mexico, until recently little published information indicating specific historic and prehistoric sites was available. Mexico ceded the area to the United States in 1848 pursuant to the Treaty of Guadalupe Hidalgo, which ended the Mexican War. The first permanent settlement was established in 1852 at San Luis by Spanish-Americans from northern New Mexico seeking arable lands. European immigrants began immigrating to the valley after 1868 when the Indians relinquished their claims to the valley (San Luis Valley Regional Development and Planning Commission).

Both the Ute Indians and Indians from the Rio Grande pueblos apparently used the valley on a seasonal basis (U.S. Department of the Interior, 1979). The United States Department of the Interior, Water and Power Resources Service (WPRS) (formerly "Bureau of Reclamation") is currently conducting cultural resource surveys in conjunction with the San Luis Valley Project -- Colorado Closed Basin Division. WPRS archaeologists anticipate the following survey results:

1. Presence of prehistoric cultural materials, which indicates "numerous short-term occupations and limited activity areas deposited over the course of more than 10,000 years."
2. "Deposits of cultural materials should be concentrated on the borders of ancient permanent ponds and seasonal wetlands, with occasional sparse 'outcrops' of artifacts representing limited activity areas more generally distributed."
3. No permanent structures in the project area, and "midden deposits representing either long-term occupation or repeated occupations of the same location by a large group are anticipated to be rare to absent." (U.S. Department of the Interior, 1979).

The WPRS Closed Basin Project archaeological survey indicates that cultural materials are distributed primarily between the elevations of 2292 and 2294 meters (7520 and 7525 feet). This finding is consistent with the results of a survey of the Blanca Wildlife Refuge conducted by Adams State College (U.S. Department of the Interior, 1979).

The following sites located in the San Luis Valley are listed on the National Register of Historic Places (Federal Register, February 6, 1979; March 18, 1980; February 3, 1981):

1. Alamosa County - none
2. Conejos County - Cumbres and Toltec Scenic Railroad (Denver and Rio Grande Western Railroad), Engine No. 463, Warshauer Mansion, La Jara Depot, Pike's Stockade
3. Costilla County - Fort Garland, Plaza de San Luis de la Culebra, Smith-Gallego House
4. Mineral County - Wagon Wheel Gap Railroad Station
5. Rio Grande County - none
6. Saguache County - Carnero Creek Pictographs, Saguache School and Jail Buildings, Saguache Flour Mill, Capilla de San Juan Bautista

3.5.2.7 Visual Resources

Figure 3-13 presents a visual sensitivity analysis for most areas of the San Luis Valley. The Bureau of Land Management conducted the analysis, which appeared as Figure II-37 in the Final Environmental Statement, San Luis Valley Resource Area, Grazing Management, issued in 1977. The Bureau of Reclamation included the analysis, with modifications, in the Final Environmental Statement, San Luis Valley Project - Colorado Closed Basin Division (1979), Drawing No. 1298-500-18.

The analysis indicates the visual sensitivity of the foreground and middle-ground in each area. Foreground, as the term is used in Figure 3-13, ranges from 0 to 1.6 kilometers (0 to 1 mile) and middleground from 1.6 to 8 kilometers (1 to 5 miles). The analysis identified the following highly sensitive features: Bonanza, Saguache, Crestone, the Baca Grande, South Fork, Del Norte, Monte Vista, Alamosa, Great Sand Dunes National Monument, Monte Vista National Wildlife Refuge, Alamosa National Wildlife Refuge, the access road to Crestone, Pikes Stockade (visually enclosed), Antonito, U.S. Highway 285, U.S. Highway 160, the Rio Grande south of the Mesitas Bridge, Cumbres and Toltec Railroad, and the southern approach to the Great Sand Dunes National Monument.

Figure 3-13 also indicates visual management classes, i.e., areas in which human impacts should not be visually evident, should be visually subordinate or may dominate the landscape without causing undue negative impacts. The visual management classes were structured by assessing the scenic quality and visual sensitivity of each area.

3.5.2.8 Socioeconomic Characteristics

Table 3-6 presents data from the 1970 and 1980 Census showing the population of each county in the San Luis Valley. Total population for the eight county area in 1980 was 37,905, an increase of 1.2 percent over the 1970 population of 37,466. In contrast, the region's population decreased in the preceding decades - between 1960 and 1970 by 2.7 percent, between 1950 and 1960 by 6.6 percent. Most of the population increase between 1970 and 1980 occurred in Alamosa County.

Table 3-6

POPULATION OF THE SAN LUIS VALLEY

<u>County</u>	<u>1970</u>	<u>1980</u>
Alamosa	11,422	11,790
Conejos	7,846	7,794
Costilla	3,091	3,071
Mineral	786	804
Rio Grande	10,494	10,511
Sagauche	3,827	3,935
Region Total:	37,466	37,905

Although 1980 Census data showing the ethnic characteristics of the San Luis Valley's population is available, statistics indicating employment and income have not been released, due to budget cutbacks and pending litigation. In 1976, however, the San Luis Valley Council of Governments prepared the San Luis Valley Labor Force Survey, which was based on interviews with a random sample of households. The survey showed that the income of 21 percent of all persons 16 and over in the San Luis Valley region was below the poverty level. Median family income was \$6289 in 1969, compared to a median income of \$9580 for the entire state (U.S. Department of the Interior, 1979).

In 1970, 4.8 percent of the area's labor force was unemployed, in contrast to a statewide rate of 4.2 percent. Persons with Spanish surnames, 46 percent of the area's population in 1970, experienced a much higher rate of unemployment -- 9 percent.

3.5.3 Impacts of the Proposed Project and Mitigation Measures

The effects of constructing and operating a commercial scale fuel grade ethanol plant in the San Luis Valley, Colorado are described in this section. Possible ways to mitigate any anticipated adverse impacts are discussed also. How biologic and cultural resources will be affected by such a plant depending on the location are chosen. Impacts on land use are also site-specific. These impacts, therefore, must be evaluated after a site is selected.

3.5.3.1 Construction

3.5.3.1.1 Air Emissions

Exhaust emissions caused by operation of heavy machinery and welding are expected to be intermittent during the construction phase of the project. Heavy equipment used for site excavation, grading and roadwork will generate dust. As noted in section 3.5.2.3, particulate levels are the principal air quality concern in the San Luis Valley at present. Wetting down the roads should minimize the problem (Kentucky Agricultural Energy Company, undated).

Another potential impact on air quality will be release of hydrogen sulfide during the testing of the geothermal wells. Preliminary estimates for the Baca Geothermal Demonstration Project in New Mexico indicated that as much as 25 to 50 pounds per hour per well of hydrogen sulfide might be released during well testing (United States Department of Energy, 1980). Until the quality of the geothermal brine in the San Luis Valley is established, no realistic estimates of how much hydrogen sulfide will be released during well testing are possible. The State of Colorado apparently does not currently regulate hydrogen sulfide emissions. States in which extensive geothermal development is occurring limit such emissions due to the odor associated with release of the gas. In California, for example, the odor threshold is 0.03 ppm. Some people detect the odor when hydrogen sulfide emissions are below this threshold level. Note that the geothermal wells needed to supply the San Luis Valley plant would be tested sequentially and intermittently, as opposed to simultaneously and continuously.

3.5.3.1.2 Labor Force

Oak Ridge National Laboratory estimated 280-375 "man-years" would be needed to construct a 15.8 million gallon per year fuel alcohol plant. Peak construction work force would be 560. The construction period is estimated to be 12 months (Oak Ridge National Laboratory, June 1981). The labor force required during drilling of the geothermal wells may vary from 5 to 30 persons.

Table 3-7 depicts the craft mix for chemical plant construction. As discussed in Section 3.5.2.8 of this report, the San Luis Valley historically has experienced a higher rate of unemployment than the State of Colorado as a whole. Perhaps at least a portion of the labor force needed to construct the proposed ethanol plant will be recruited from the available labor pool, causing a positive impact on the community.

3.5.3.2 Operation

Production of fuel grade ethanol involves the following steps:

1. initial processing
2. cooking
3. fermentation
4. distillation and dehydration
5. by-product recovery

In addition, for the project discussed in this study, geothermal fluid will be produced for direct heat use. The following discussion describes how the proposed plant may affect air and water quality, solid waste disposal, noise levels, traffic, employment, community services and visual resources.

3.5.3.2.1 Air Quality

Oak Ridge National Laboratory recently completed a study for the Department of Energy on the impacts a commercial scale ethanol plant might have on the environment. Table 3-8, reprinted from that study, indicates the estimated major atmospheric effluents from a 60 million liters/year (15.85 million gallons/year) alcohol plant using various feedstocks and fuel combustion sources.

a. Initial Processing

The proposed San Luis Valley plant will process potatoes and various grains. Dust and dirt will be generated during unloading of potatoes and preparing them for washing.

The primary air emission during grain processing will be particulates. The Oak Ridge Report estimated that a 60 million liters/year (15.85 million gallons/year) alcohol plant (Model Plant) will generate 49.4 kilograms per hour (431 tons per year) of particulates or dust during the process of dry-milling corn (Oak Ridge National Laboratory, June 1981). This estimate is based on the assumption that the ethanol producer will use best available control technology.

The Colorado Department of Health gave initial approval for an Emission Permit for the Colorado Agro-Energy, Inc. to operate a 1.5 million gallon per year ethanol plant in the San Luis Valley, Colorado. The permit specifies:

Table 3-7
CRAFT MIX FOR CHEMICAL PLANT CONSTRUCTION^a

Craft	Percentage of Workforce
Carpenter	18
Laborer	18
Electrician	11
Plumber/pipefitter	10
Bricklayer	8
Iron worker	6
Cement worker	5
Sheet metal	5

^aDoes not total 100% because crafts requiring less than 5% of total are not included.

Source: Oak Ridge National Laboratory, June 1981, Draft Generic Environmental Assessment Report for Conventional Fuel Alcohol Plants.

Table 3-8

ESTIMATED MAJOR ATMOSPHERIC EFFLUENTS FROM 60 MILLION LITERS/YEAR
(15.85 MILLION GALLONS/YEAR) ALCOHOL PLANT

	Sulfur Dioxide	Hydrocarbons	Particulates or dust	Carbon Monoxide	Carbon Dioxide	Drying Chemicals	Nitrous Oxides
	kg/h (ton/year)	kg/h (ton/year)	kg/h (ton/year)	Kg/h (ton/year)	kg/h (ton/year)	kg/h (ton/year)	ky/h (ton/year)
Alcohol production effluent							
Corn, dry-milling		n	49.4 (431)		5,895 (51,465)		
Corn, wet-milling	4.2 (36.7)	n	14.7 (128)		5,895 (51,465)		
Sugarcane, raw juice		n			5,895 (51,465)		
Distillation and dehydration							
Benzene		0.038 (0.33)					
Ethylene glycol		0.038 (0.33)				1.2 (10.5)	
Ethyl ether		0.038 (0.33)				0.3 (2.6)	
Gasoline		0.038 (0.33)				3.8 (33.2)	
						3.8 (33.2)	
Fuel Combustion Effluents							
Coal							
corn	19.0 (166)	4.8 (42)	n				30.0 (262)
sugarcane	50.0 (436)	12.6 (110)	n				79.0 (690)
Bagasse, sugarcane	20.8 (182)	138.0 (1,205)	164.0 (1,432)	441.0 (3,850)			138.0 (1,205)
Wood							
corn	7.0 (61)	52.0 (454)	62.0 (541)	168.0 (1,467)			52.0 (454)
sugarcane	20.8 (182)	137.0 (1,196)	163.0 (1,423)	442.0 (3,858)			137.0 (1,196)
Natural gas							
corn	0.02 (0.17)	0.1 (0.9)	0.6 (5.2)	0.7 (6.1)			10.0 (87)
sugarcane	0.05 (0.45)	0.3 (2.6)	1.6 (14.0)	1.8 (15.7)			26.0 (227)

* Not significant (present in only trace amount)

Source: J. L. Otis, R. S. Davidson, and T.S. Reddy, Process Design Support for a Generic Environmental Assessment of Conventional Alcohol Fuel Facilities, prepared by Battelle Columbus Laboratories for Union Carbide Corporation, Nuclear Division, 1981; reprinted from Draft Generic Environmental Assessment Report for Conventional Fuel Alcohol Plants, Oak Ridge National Laboratory, June 1981.

1. Opacity shall not exceed 20 percent.
2. Particulate emissions shall not exceed 0.11 pounds per million BTUs or 16.97 tons per year for wood waste combustion. Particulate emissions shall not exceed 0.0003 pounds per million BTUs or 0.001 tons per year for oil combustion.

Installation of baghouse filters and cyclones will reduce particulate emissions during the grain processing phase and later during by-product processing. Also, an ethanol producer should employ standard grain industry practices to avoid respiratory healthy hazards to workers and explosion hazards stemming from grain dust (Solar Energy Research Institute, November 1980).

b. Cooking, Fermentation, Distillation and Dehydration

During fermentation, large amounts of carbon dioxide will be generated. Oak Ridge estimates the Model Plant described above will produce 5895 kilograms per hour (51,465 tons per year) of carbon dioxide (Oak Ridge National Laboratory, June 1981). There are presently no limits on atmospheric emission of carbon dioxide (Kentucky Agricultural Energy Company, undated). Use of water scrubbers and absorption filters should remove most of the unpleasant odor associated with fermentation gases. The atmospheric effluent will primarily be carbon dioxide and also will contain approximately 1.5 percent water, 0.4 percent ethanol and 0.25 percent aldehyde. Currently there are no air emission standards for ethanol.

During the distillation and dehydration stages of the ethanol production process, small amounts of hydrocarbons will be vented to the atmosphere. No mitigation will be needed. Section 166 of the Clean Air Act requires the EPA to study hydrocarbons and to issue regulations by 1981 if needed. At the present time, no emissions limitations are placed on hydrocarbons, however, there is a federal ambient air quality standard of $160 \mu\text{g}/\text{m}^3$.

c. Production of Geothermal Fluid

The geothermal brine will be flashed to steam in two stages to produce the steam required for ethanol production (see Section 5.5). At each stage hydrogen sulfide might be discharged to the atmosphere. The quantity of discharge is unknown at this time, however, because little information is available on the chemical constituents of the brine. Hydrogen sulfide emissions are not monitored or restricted in the San Luis Valley at present. Much of the hydrogen sulfide contained in the geothermal fluid could be removed by a Stretford process or other abatement system, if the hydrogen sulfide content of the brine makes installation of such a system necessary.

3.5.3.2.2 Water Quality

The consensus of environmental authorities is that an ethanol producer whose process includes processing of stillage and water treatment will encounter no difficulty in meeting current water effluent guidelines (Oak Ridge National Laboratory, June 1981; Solar Energy Research Institute, November 1980; Kentucky Agricultural Energy Company, undated). One study states that a 50 million gallon per year plant will generate 1.1 million gallons of wastewater per day if water is extensively recycled (Solar Energy Research Institute, November 1980). According to this source, prior to treatment wastewater will contain 25,000 pounds per day total solids, 3000 pounds per day suspended solids, 7300 pounds per day biological oxygen demand (BOD) and some acidity.

The State of Colorado's effluent standard for BOD is 30 milligrams per liter (a seven day average) or 45 milligrams per liter daily maximum. Several commercial biological oxidation systems are available. Adjustment of pH (prior to discharge) to between 6 to 9 to satisfy federal standards (Oak Ridge National Laboratory, June 1981) will be required. Preliminary screening and sedimentation in a holding tank prior to biological oxidation should remove sufficient suspended solids for compliance with federal water quality standards.

After wastewater from the ethanol plant receives primary and secondary treatment, it will be discharged to the most feasible canal or stream in the area. The Colorado Department of Health determines whether a water discharge satisfies the requirements for a National Pollutant Discharge Elimination System (NPDES) under the Clean Water Act by applying the Q 7 10 flow rate for the receiving stream and the maximum flow rate for the discharge stream (Shukle, Robert, 1981).

Although the state regulates location of domestic wastewater treatment facilities, no site permit is required for an industrial wastewater treatment plant. The State Department of Health does advise industrial operators regarding treatment facility design if the operator has difficulty meeting state and federal water discharge requirements.

Direct application of wastewater to land surfaces is not regulated by the federal government because the term "waters of the nation" does not encompass groundwater within the meaning of the Clean Water Act. However, Colorado began regulating application of wastewater to land in June 1981. It is evident, therefore, that an on-site treatment plant is needed for the wastewater generated by an ethanol production facility.

All geothermal fluid not consumed in the ethanol process will be reinjected. Fluid which is reinjected is exempt from regulation under current NPDES permitting procedures. The brine cleanup system designed for the project is described in Section 5.7.

3.5.3.2.3 Solid Wastes

The Oak Ridge Report recommends that ethanol producers consider access to approved solid waste disposal sites during the design and site selection phases (Oak Ridge National Laboratory, June 1981). Approximately 3975 kilograms per hour (8770 pounds per hour) of solid waste will be generated by the Model Plant. Geothermal wastes generated by the proposed San Luis Valley facility are exempt from the Resource Recovery and Conservation Act (RCRA) (see Section 3.6.4). The Oak Ridge Report concludes that none of the wastes associated with alcohol production are classified as hazardous solid waste under RCRA. Table 3-9 lists existing solid waste systems in the San Luis Valley.

3.5.3.2.4 Noise

No problems are anticipated regarding external noise due to the probable location of the ethanol production facility in an area with few sensitive receptors. There are also plans to place much of the machinery in buildings and to incorporate baffling in the design wherever appropriate.

3.5.3.2.5 Traffic

The Department of Energy Draft Generic Environmental Assessment Report for Conventional Fuel Alcohol Plants concludes that the severest impact on local communities during the operational phase will likely be related to transportation of feedstocks to the facility (Oak Ridge National Laboratory, June 1981). If feedstock is transported via truck, as is planned for the San Luis Valley plant, 24 round trips per day will be required for a 60 million liters per year (15.85 million gallons per year) plant (Oak Ridge National Laboratory June 1981). In addition, trucks will carry solid waste for the plant to a disposal site. Increased truck traffic may cause traffic congestion, safety hazards, road wear and noise. Automobile traffic will also increase as operations and maintenance employees travel from the population centers to the rural plant location. Figure 3-9 depicts main and secondary roads in the study area.

3.5.3.2.6 Employment

Fewer employees will be needed to operate and maintain the alcohol production plant than during the construction phase. In addition, since less specialized skills will be needed, it is probable that more local residents will work at the facility.

Table 3-9

REGION 8

EXISTING SOLID WASTE SYSTEMS

Community	Location of Disposal Site	Type of Disposal	Major Problem
Alamosa	1 mile south	Sanitary landfill	None
Antonito	2 miles south	Uncontrolled dumping	Blowing debris
Blanca	4 miles southeast	Uncontrolled dumping	Blowing debris
Bonanza	one-half mile west	Uncontrolled dumping	Possible stream pollution
Capulin Center	1 mile south 7 miles west	Uncontrolled dumping Controlled dumping	Blowing debris Possible blowing debris
Chama	three-fourths mile south	Uncontrolled dumping	Blowing debris
Creede	2 miles southeast	Sanitary landfill	Blowing debris
Crestone	1 mile south	Uncontrolled dumping	Blowing debris
Del Norte	3 miles northwest	Uncontrolled dumping	Blowing debris
Fort Garland	three-fourths mile south	Uncontrolled dumping	None
Garcia	one-fourth mile northeast	Uncontrolled dumping	Blowing debris
Guadalupe	2 miles south of Antonito	Controlled dumping	Blowing debris; unsatisfactory disposal of dead animals
Hooper	1 mile east	Uncontrolled dumping	Blowing debris
La Jara	3 miles east of Sanford	Uncontrolled dumping	Blowing debris
Manassa	5 miles east	Uncontrolled dumping	None
Moffat	one-fourth mile west	Uncontrolled dumping	Blowing debris and water pollution
Monte Vista	3 miles southwest	Controlled dumping	Blowing debris and bulky items
Mosca	one-fourth mile east	Uncontrolled dumping	Blowing debris
Romeo	5 miles east of Manassa	Uncontrolled dumping	None
Saguache	1 mile east	Uncontrolled dumping	Blowing debris
Sanford	3 miles east	Uncontrolled dumping	Blowing debris
San Luis	1 mile east	Uncontrolled dumping	Blowing debris
South Fork	3 miles northeast	Uncontrolled dumping	Unightly

Source: Davis Engineering Service, Inc.: Solid Waste Study for the San Luis Valley Region, Colorado and Oblinger - Smith Corporation, Consultants in Planning, Design and Development, 1971; reprinted from Draft San Luis Valley Overall Economic Development Plan, undated, prepared by San Luis Valley Regional Development and Planning Commission.

An estimated work force of 60 to 125 persons will be needed to operate a 60 million liters per year (15.85 million gallons per year) plant (Oak Ridge National Laboratory, June 1981). Estimates of work force size for larger facilities are unavailable.

3.5.3.2.7 Community Services

The influx of workers, particularly during construction, is expected to impact the ability of local government to provide public services. Some of this impact will be temporary. Because the main source of income for counties in the San Luis Valley is the property tax, however, government's ability to finance expanded services may lag behind the need. The capacity of rural school systems is of particular concern (Oak Ridge National Laboratory, June 1981).

3.5.3.2.8 Visual Impact

The overall appearance of the proposed ethanol plant and geothermal wellfield will be horizontal. All of the permanent buildings will be one-story. Although the wellfield will be visually evident during the drilling phase, during operations the well height will be about 3 feet. The distillation column and grain silos will be about 65-75 feet high. Potatoes will be stored outside kept in below-ground pits. Any industrial development in the rural areas of the San Luis Valley is likely to have a strong visual impact. One consideration in selecting a site should be the effect of the plant on visually sensitive areas (see Figure 3-13).

3.5.3.2.9 Community Acceptance

Community attitudes toward geothermal development in the Valley appear to be favorable. In a recent report evaluating geothermal energy potential for the San Luis Valley (Coe, 1980), reference is made to an economic development questionnaire posited to the San Luis Valley Council of Governments (SLVCOG).

A compilation of the results of the questionnaire ranks economic projects in priority order. Among the high priority projects are the preservation of the agricultural industry, development of agricultural processing plants, and alternative energy development. Specifically, the goal of new or expanded agricultural resource/energy plants ranked 12th out of the 28 economic categories evaluated. New agriculture commodity processing firms as a means of developing the local economy was near the top of the list, ranking 4th in SLVCOG's list of priorities. Priorities 1 and 2 centered on agricultural and community water projects, obviously reflecting local concern for preserving this resource. From the above, it may be inferred that the community would welcome an ethanol operation utilizing the agricultural commodities of the region as well as an alternative energy resource. Furthermore, if the feedstocks

selected for the process minimized the consumptive use or even increased the supply of water, it appears the SLVCOG concern for water availability would be addressed, albeit in a small way.

3.5.3.2.10 Summary

Location of a fuel grade ethanol plant in San Luis Valley, Colorado raises no major environmental issues. Environmental controls previously developed to limit impacts caused by sewerage grade alcohol plants (Oak Ridge National Laboratory, June 1981) and other geothermal operations are available for application in a fuel grade geothermally heated facility. Some adverse impact is anticipated if the proposed plant is located in a rural area where little or no industry is presently located.

3.6 REGULATORY CONSTRAINTS ANALYSIS

3.6.1 Introduction

Regulatory requirements potentially applicable to a developer planning to construct an ethanol plant using geothermal energy in the San Luis Valley, Colorado are analyzed in this section. It was known at the start of the project that one major constraint to construction of any new ethanol production facility was the shortage of water in the San Luis Valley. The State of Colorado, as with most arid western states, carefully monitors water usage by granting or denying rights to the consumptive use of water. As described in other sections of this report, there are three major areas in which water may be consumptively used in the geothermal ethanol process: 1) withdrawal of the geothermal fluid itself; 2) for cooling purposes primarily during fermentation; and 3) for feedstock preparation. Therefore, the regulatory section addresses the system of acquiring rights to the geothermal fluid and to water. To the extent that the consumptive use of water is reduced by reinjection and by designing the ethanol facility for a mix of feedstocks requiring little water, the concerns associated with water rights acquisition may be diminished on an annual basis. Nevertheless, an operator must still seek permission to withdraw the geothermal fluid.

Of equal concern to the constraints analysis is the environmental impacts associated with project development (Section 3.5). Particular emphasis is placed on federal statutes such as the Resource Conservation and Recovery Act, the Endangered Species Act and the National Historic Preservation Act because these statutes and the regulations implementing them significantly affect many industrial developments.

3.6.2 Geothermal Leasing

A developer must secure the right to utilize the fluid produced from any geothermal reservoir. Typically, the developer acquires the right to drill by lease

acquisition from the landowner. In the San Luis Valley, the landowner may be the federal or state government or a private owner. Leases from the former are granted pursuant to statute and regulations. Leasing from a private landholder can be accomplished through a negotiated contract between the parties.

3.6.2.1 Geothermal Leasing on State Lands

Alamosa County, of particular interest to this study because of its proximity to existing moderate temperature wells, contains 19,930 hectares (49,250 ac) of land owned by the State of Colorado. Of this total, in December 1978, active state geothermal leases covered 6600 hectares (16,303.33 ac) (Coe, 1980). The State Board of Land Commissioners issues all geothermal leases on land owned by the state. In addition, the Board has the authority to issue permits for exploration, development, unitization, and communitization. Application procedures for these permits are thoroughly described in two sources: Colorado Permit Directory for Energy and Mineral Development (Colorado Joint Review Process Program, 1980) and Regulation of Geothermal Development in Colorado (Coe & Forman, 1980). The Board must hold a public auction if two or more persons want to lease the same acreage. However, due to lack of competitive interest, thus far all leases have been issued on a non-competitive basis (Coe & Forman, 1980).

3.6.2.2 Geothermal Leasing on Federal Land

To lease geothermal resources located on federal land, an operator must follow procedures outlined in the Geothermal Steam Act of 1970 (30 U.S.C. 1001-1025) and Department of Interior regulations implementing the Act (43 C.F.R. 3200 et seq.). The Bureau of Land Management (BLM) handles issuance of leases on all federal land. Alamosa County contains 34,100 hectares (84,258 ac) of land owned by the federal government. BLM-issued non-competitive geothermal leases active in December 1978 covered 1610 hectares (3976.38 ac) (Coe, 1980). Apparently BLM has sold no competitive leases within the Alamosa County Known Geothermal Resource Area (KGRA). Many private landowners in Alamosa County have leased rights to geothermal resources underlying their property to oil companies and other corporations interested in developing geothermal energy.

A developer seeking a geothermal lease from BLM should consult the Colorado Permit Directory for Energy and Mineral Development (Colorado Joint Review Process Program, 1980) and Regulation of Geothermal Development in Colorado (Coe & Forman, 1980) for information regarding permitting requirements.

3.6.3 Geothermal Exploration and Development

Regardless of the nature of land ownership, all geothermal operators must comply with the requirements of the Colorado Oil and Gas Conservation Commission (OGCC). Pursuant to the Colorado Geothermal Act (Colo. Rev. Stat., 1973, 34-70-101-110), the Commission regulates, through its permitting system, all aspects of drilling observation, exploratory, and development wells. It must be emphasized, however, that this system is closely tied to the administration of water rights by the State Engineer and Groundwater Commission. No well may be drilled without a finding that water rights held by others will not be injured.

3.6.3.1 Oil and Gas Conservation Commission

An operator must obtain a permit from OGCC before drilling, deepening, re-entering or operating a geothermal well in the State of Colorado. Information which the Commission requires the applicant to provide includes: description of the lease; a plat map showing the exact location of the well; depth of the proposed well; effect on the land surface; plans to avoid land subsidence, air and water contamination and noise excess; geothermal brine disposal and by-product recovery; and description of the casing program.

The Commission retains a bond of \$10,000 for each well or \$50,000 for all of the applicant's wells to assure compliance with well plugging and reporting regulations. The state does not require a bond if the operator posts a bond with the BLM on a federal lease (Coe & Forman, 1980). The operator must comply with all other OGCC requirements, however. In addition, where the lease is on federal land, the lessee must submit a Plan of Operations to the U.S. Geological Survey (USGS). Approval of this Plan, which must contain much of the information required by the state, is needed before all but preliminary exploration and casual use activities are begun.

3.6.3.2 Division of Water Resources, Office of the State Engineer

The OGCC submits applications to drill geothermal wells to the Colorado Division of Water Resources for review before deciding whether to issue the drilling permit. The Division's purpose in reviewing the application is to approve only those geothermal operations which will not adversely affect existing water rights.

Water rights in Colorado are established under the doctrine of appropriation. The water rights of a user who perfects his rights to such use under the applicable statutes are protected from actions by junior appropriators detrimental to his use. The Division of Water Resources administers the statutory scheme for perfecting water rights under the doctrine.

If the Division determines that the proposed geothermal activity will affect water rights, the operator must acquire water rights. In Colorado the procedure for perfecting rights to groundwater depends on whether the Division classifies the water as 1) groundwater tributary to a stream; 2) groundwater in a designated basin; or 3) non-tributary, non-designated groundwater. There are substantive rules for dealing with each.

Appropriation of groundwater tributary to a stream is regulated under the Water Right Determination and Administration Act of 1969 (Colo. Rev. Stat., 1973, 37-92-101 to 37-92-602. Groundwater is presumed tributary to a stream if it is hydrologically connected to a stream and "can influence the rate or direction of movement of the water" in the stream (Colo. Rev. Stat., 1973, 37-92-103(11)).

A person who proposes to drill a well which withdraws groundwater tributary to a stream must obtain a permit from the State Engineer. The State Engineer must issue the permit if he concludes that: 1) there is unappropriated water available; 2) the vested rights of other appropriators will not be injured; and 3) the well is at least 600 feet from existing wells.

Receipt of this permit, however, enables the driller only to construct the well and withdraw water. If the geothermal fluid will be consumptively used, the operator is required to file an application for water rights in the division water court. The water court relies heavily on the State Engineer's decision whether to grant a permit to drill (construct) a well before granting a "conditional" water right.

A conditional water right grants applicant a specific priority date for the right, if he completes the appropriation with reasonable diligence. Once completed, a "final" water right may be granted after repeating the procedure in the division water court (Gould, 1979).

Again, it should be noted that the applicant need apply to the water court only if a consumptive use of water is anticipated. If the withdrawn geothermal fluid is in a closed system with only heat being extracted and all brine reinjected, no court-issued water right would likely be needed (Coe and Forman, 1980).

If a driller plans consumptive use of groundwater from a designated groundwater basin, the Groundwater Management Act controls (Colo. Rev. Stat., 1973, 37-90-101 to 37-90-141). This Act defines designated groundwater as that water within the geographic boundaries of a designated groundwater basin (Colo. Rev. Stat., 1973, 37-90-103(6) to 90-103(8)) as established by the Groundwater Commission.

The Commission regulates the permitting system established for acquiring water rights. Like the permit associated with groundwater tributary to a stream, an applicant must first secure a conditional permit and put the water to a beneficial use before securing the final right to appropriate. Perfecting appropriative rights in a groundwater aquifer, however, does not guarantee the driller that the pumping level at the time he perfected his water rights will be maintained in the future. The Groundwater Management Act only provides for protection of prior appropriations and maintenance of "reasonable" groundwater levels (Colo. Rev. Stat., 1973, 37-90-102).

Note that it is the Groundwater Commission which grants the permit. The permit is issued only if the Commission finds that: 1) there is unappropriated water; 2) senior rights will not unreasonably be impaired; and 3) the new right will not cause unreasonable waste.

No further discussion of water rights related to designated groundwater basins is appropriate. There are no such basins located within the San Luis Valley. (The Closed Basin project is not a designated basin, but a special project operated in conjunction with the federal government.)

The final category of groundwater is that water which is not tributary to a stream and not in a designated groundwater basin. To construct a well in this area, an applicant must secure a permit from the State Engineer. Again, the applicant must persuade the State Engineer that there is unappropriated water available and that the well will not interfere with the rights vested in others.

However, in making his determination, the State Engineer is constrained to consider only that quantity of water underlying the land owned by applicant as being appropriable. Moreover, the minimum useful life of the aquifer is presumed to be 100 years, assuming no substantial artificial recharge within that period (Olpin et al., 1980).

The net effect is to limit pumping from these deep aquifers in any given year to 1 percent of the water stored under the applicable area. Any water derived from geothermal sources would probably fall into this category, and this production of geothermal resources which can be classified as groundwater by the State Engineer will be limited by the Colorado Ground Water Management Act (Schlauch & Worcester, 1974).

If it were not possible to appropriate or to purchase groundwater near the facility and yet water were needed for its operation, one remaining option would be to

acquire rights elsewhere and to transport water to the site. Colorado permits surface water and groundwater tributary to a stream to be transferred and used anywhere within the state (Gould, 1979). On the other hand, the transport of designated groundwater may be prohibited by the appropriate groundwater management district where such use "materially affects the rights acquired by permit by any owner or operator of land within the district" (Colo. Rev. Stat., 1973, 37-90-130(2)(f)). Based upon a discussion with the Division of Water Resources, it may, however, be difficult or impractical to secure water from one area to utilize in another district (pers. comm., McFadden, 1981).

3.6.4 Environmental Impact Review

Colorado has no state legislation comparable to the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321 et seq.). Therefore, formal evaluation of the impact of the proposed ethanol plant on the environment will take place only if federal involvement requires compliance with NEPA, or local governments require environmental review before granting building permits for the installation.

A federal agency might be sufficiently involved in the plant to invoke NEPA's provisions if the operators receive federal loan guarantees or subsidies or the facility and/or the geothermal wells are located on federal land. Some land in the Alamosa County KGRA is federally owned. Federal loan guarantees and grants have been available to encourage both geothermal development and alcohol fuels production. Whether these federal programs may be discontinued as a result of budgetary cutbacks in 1981 is unknown as yet.

3.6.5 Regulation of Hazardous Waste Disposal

The Environmental Protection Agency (EPA) issued regulations, effective November 19, 1980, which were authorized under the Resource Conservation and Recovery Act of 1976 (RCRA) (42 U.S.C. § 6901 et seq.). The subject of the regulations is hazardous waste disposal (40 C.F.R. Part 261). First the term "solid waste" is defined. Then the term "hazardous waste" is explained. Basically, a solid waste is classified as a hazardous waste if it has the characteristics of such waste described in the regulations, i.e., ignitability, corrosivity, reactivity or toxicity.

"Drilling fluids, produced waters, and other waste associated with the exploration, development, or production of crude oil, natural gas or geothermal energy" are expressly excluded from the definition of hazardous waste (40 C.F.R. 261.4(b)). The Region IX office of the EPA informally interpreted the geothermal exclusion rather narrowly. Under this interpretation, for example, waste associated with the production

of geothermal energy is exempt only to the point where the fluid is pumped to the surface. Waste associated with use of geothermal energy for direct heat or power generation is not exempt.

A generator of hazardous wastes must comply with the following regulatory requirements:

1. Obtain an EPA identification number.
2. Properly label and store hazardous waste prior to transportation off-site.
3. Complete forms which must accompany all hazardous waste transported offsite.
4. Keep records and submit reports.

A "small quantity generator" is exempt from most of these requirements. The regulations define a "small quantity generator" as one who generates less than 1000 kilograms (2200 lbs) of hazardous waste per calendar month (40 C.F.R. 261.5(a)).

The regulations place on the generator the burden of determining whether solid waste is hazardous (40 C.F.R. 261.11). Statutory penalties for noncompliance provide for a maximum civil penalty of \$25,000 for each day a generator fails to comply with an EPA order. Criminal penalties for knowingly violating RCRA are \$25,000 per day of violation and/or imprisonment for no more than 1 year for the first violation. Subsequent convictions may result in fines up to \$50,000 per day and/or imprisonment for no more than 2 years.

Colorado has not enacted statutes addressing the disposal of hazardous wastes. Therefore, generators of hazardous waste need comply only with federal law. Legislation has been introduced in the Colorado State Legislature which would enable the state to administer RCRA within Colorado.

3.6.6 Air Quality

3.6.6.1 Prevention of Significant Deterioration Permit

The EPA requires a Prevention of Significant Deterioration (PSD) permit if emissions of "controlled" pollutants subject to regulation under the Clean Air Act (42 U.S.C. § 7401 et seq.) potentially exceed 90,800 kilograms (100 tons) per year from a source specified on EPA lists or 227,000 kilograms (250 tons) per year from non-listed sources. The term "controlled" emissions means emissions which EPA has authority to regulate or which a local air pollution control district has authority to regulate pursuant to a delegation of authority by EPA.

3.6.6.2 Air Pollution Control Division Permit

Any new or modified source of atmospheric pollution must be reviewed by the Colorado Air Pollution Control Division (APCD), which determines whether a waiver is appropriate or the applicant must receive a permit. The operator must bear the costs for expert evaluation of emission levels. The authors of the Colorado Permit Directory recommend that all energy and mineral developers meet with the APCD prior to filing any permit applications to find out what requirements are applicable (Colorado Joint Review Process Program, 1980). If a permit is required, the applicant may construct and begin operations on the basis of the initial permit. The Division usually issues the final permit within 30 days of start-up if the operator complies with all permit conditions. Compliance includes taking periodic emission readings.

3.6.7 Water Quality

3.6.7.1 National Pollution Discharge Elimination System Permit

The Federal Water Pollution Control Act Amendments of 1972 (Pub. L. No. 92-500) and the Clean Water Act of 1977 [ch. 758, tit. I, § 101, 86 Stat. 816 (codified in scattered sections of 33 U.S.C. (1976 and Supp. 1977))] were enacted to control the discharge of pollution into U.S. waters. Because Colorado regulations which govern point source discharges into state waters meet federal standards, the state administers these federal laws. Where applicable, separate permits, one for discharge into surface waters, the other for discharge into subsurface waters, may be obtained by applying to the state Water Quality Control Division (WQCD). The EPA reviews any application for a National Pollutant Discharge Elimination System (NPDES) permit to discharge into surface waters. If the EPA denies an application for an NPDES permit, the applicant may petition for review in a United States Court of Appeals (33 U.S.C. § 1369).

In some instances the WQCD waives compliance with pollution standards for subsurface reinjections. The EPA currently exempts closed cycle geothermal reinjection operations from water pollution regulations, while the agency decides, after observation, whether there is a danger of seepage and whether geothermal fluid should be classified as hazardous.

3.6.7.2 Section 404 Dredge and Fill Permit

The Clean Water Act also provides the statutory basis for federal control of wetlands and shoreline areas. Section 404 of the Act provides that the Army Corps of Engineers, in accordance with guidelines developed by the EPA, may issue permits for discharge of dredged or fill materials into waters of the United States.

The term "waters of the United States" is defined very broadly in section 230.3(s) of the EPA guidelines (45 Fed. Reg. 85336 et seq. (December 24, 1980)). It includes intrastate wetlands "which are used or could be used for industrial purposes by industries in interstate commerce." "Wetlands" are defined as "areas that are inundated or saturated by surface or groundwater at a frequency and duration sufficient to support, and under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions (sec. 230.3(t)). Portions of the San Luis Valley are characterized as "sump." The water table is quite high and water frequently collects on the land surfaces. The U.S. Fish and Wildlife Service (USFWS) estimates there are 19,020 hectares (47,000 ac) of wetlands within the Closed Basin Division, San Luis Valley Project area comprising 55,850 hectares (138,000 ac) in Alamosa and Saguache Counties (U.S. Department of Interior, 1979). Compliance with section 404 may be necessary, therefore, if land fill is contemplated in connection with constructing an ethanol facility.

3.6.8 Endangered Species Act Review Process

The Endangered Species Act (ESA) (16 U.S.C. § 1531 et seq.) applies to actions authorized, funded, or carried out by federal agencies. Agency action includes issuing leases, rights-of-way, permits or grants-in-aid, as well as actions which directly or indirectly cause changes in the land, water or air (50 C.F.R. 402.02 (1978)).

With respect to the proposed ethanol plant in the San Luis Valley, for example, ESA's provisions would impact the project if it were located on federally-owned land or received federal financial backing. In Nebraska v. Rural Electrification Administration, 12 ERC 1156 (1978), for example, federal loan guarantees for a nonfederal hydroelectric project were characterized as sufficient federal involvement that the defendant REA was required to consult with USFWS as the Act specifies. The plaintiff could not obtain an injunction against the nonfederal sponsors, however, because the loan guarantees were an insufficient nexus between the federal agency and the nonfederal sponsors.

Any federal agency engaging in an action within the scope of ESA must request that the Secretary of the Interior determine "whether any species which is listed or proposed to be listed may be present in the area" (16 U.S.C. § 1536 (c)(1)). (Practically speaking, USFWS performs the functions ESA grants the Secretary.) If the Secretary decides that such species may be present, the requesting agency must prepare a "biological assessment" which is in turn reviewed by the Secretary. This officer issues an "opinion" which states: 1) the project will not in all likelihood jeopardize a species

or cause adverse modification of a critical habitat; 2) although the project may affect a listed species or critical habitat, specified "reasonable and prudent alternatives" are available; or 3) conflict with ESA's requirements cannot be avoided through use of "reasonable and prudent alternatives."

If the Secretary's "opinion" falls within the first category described above, the requesting agency may go ahead with the project but must fulfill its duty to conserve endangered species and critical habitat. Under the second alternative, the requesting agency must develop a modified project plan using alternatives acceptable to the Secretary. Under the third category, where in the Secretary's opinion no suitable alternatives are possible, the requesting agency cannot proceed with the project unless it receives an exemption from the Secretary.

ESA could have a significant effect on the development of a project, even a project located on privately-owned land. For example, the USFWS might determine that a critical habitat for an endangered species exists on privately-owned land. If the landowner did not plan to develop the land in a manner involving federal agency action such as funding or loan guarantee, he may have lacked incentive to participate in the process whereby the USFWS made the determination. Another important effect ESA may have on a project located on privately-owned land involves the required "recovery plan" (16 U.S.C. § 1533(g)). After the Secretary includes a species or habitat on the list, he must develop a recovery plan aimed at conserving the species or habitat. Again, the property owner may have had no input regarding a recovery plan affecting his use of private property.

Finally, in TVA v. Hill, 437 U.S. 153 (1978), the United States Supreme Court, interpreting ESA in a case involving snail darters, stated that the intent of Congress was to give endangered species priority over the primary mission of federal agencies. In contrast to the requirements of NEPA, which basically requires federal agencies to consider the effects of their activities on the environment before proceeding, ESA apparently gives the Secretary of the Interior and USFWS authority to protect elements of the environment even though programs Congress has authorized other federal agencies to implement may be affected.

3.6.9 Archaeological Clearance

An archaeological clearance is required prior to any construction on federal land or on a project which involves federal funding or permitting (National Historic Preservation Act (NHPA) 16 U.S.C. § 470 et seq.). The developer contacts the local federal land management, funding, or permitting agency to obtain a list of

archaeologists holding Federal Antiquities Permits. For example, if construction will take place on BLM-managed land, the Department of Interior should be contacted. The developer then selects an archaeologist to make an archaeological survey of the site.

The purpose of the archaeological survey is to determine whether any National Register eligible sites are located in the construction area. Although property may not be listed on the National Register if the property owner does not concur in its nomination, the Secretary of the Interior may still designate the property a "National Register eligible" site. Federal agencies must consider the effect of the proposed project on any cultural asset "included in or eligible for inclusion in the National Register" (NHPA § 106). Under the 1980 amendments to NHPA, federal agencies must plan and act, to the maximum extent possible, to minimize harm to National Historic Landmarks (Pub. L. No. 96-515). The list of sites currently in the National Register is published in the Federal Register with yearly updating (see Section 3.5.2.6 for sites located in the San Luis Valley which are listed on the National Register of Historic Places).

Following federal agency review of the archaeological survey performed on behalf of the developer, the survey is submitted to the State Historic Preservation Office for its concurrence. The State of Colorado also requires an archaeological clearance prior to construction on state-owned land.

3.6.10 Land Use Regulation

This discussion will concentrate on regulations affecting land use in Alamosa County because it contains the Alamosa County Known Geothermal Resource Area (KGRA) -- a potentially significant location for geothermal development. Figure 3.14 illustrates land ownership. Note that much of the land in Alamosa County is owned by the state or federal government. State-owned land is administered by the State Board of Land Commissioners. With respect to federally owned land, the Bureau of Land Management, Forest Service, Park Service, and Fish and Wildlife Service administer land use in Alamosa County.

Portions of the land within the Alamosa County KGRA are privately owned. Alamosa County regulates the use of this land. Although the San Luis Valley Council of Governments formulated a Regional Comprehensive Plan (Plan) for the entire San Luis Valley Region, this document provides only a guide for the county governments within the region. Counties are not required by law to adopt zoning ordinances and other land use regulations which conform to the Plan. The Plan for Alamosa County indicates that the privately owned land in the KGRA is highly suitable for future development; federal and state-owned land is of low suitability for development.

SOURCE: Regional Comprehensive Plan, San Luis Valley Council of Governments, 1974

Alamosa County Land Ownership

**FIGURE
3-14**

Alamosa County has zoned the KGRA "rural." To obtain a Conditional Use Permit allowing industrial development, a plant operator must apply to the Alamosa County Planning Commission and appear before the Commission and the County Board of Commissioners. Completing this procedure involves 30 to 90 days because the Commission must publish notices and provide opportunity for a public hearing.

Any county with a population of 65,000 or more is authorized under Colorado Revised Statutes 34-1-301 et seq. (1973) to develop a master plan for extraction of mineral deposits. Alamosa County's population in 1980 was 11,799. The county has no requirements which specifically regulate geothermal operations.

3.6.11 Alcohol Fuel Producers Permit

Any person planning to operate a plant to produce, process, store, use or distribute distilled spirits to be used solely for fuel must obtain an Alcohol Fuel Producers Permit from the U.S. Department of the Treasury - Bureau of Alcohol, Tobacco and Firearms (ATF). In response to Public Law No. 96-223, ATF recently simplified procedures for obtaining the permit. Before operating a small plant (producing not more than 10,000 proof gallons annually), the applicant must complete a two-page form (ATF Form 5110.74). With respect to medium plants (producing more than 10,000 but not more than 500,000 proof gallons annually) and large plants (producing more than 500,000 proof gallons annually), additional information is required. For example, the applicant must state:

- 1) the identity of the principal persons involved in the business,
- 2) whether any of these individuals has been convicted of a federal or state felony or misdemeanor, and
- 3) the amount of funds invested and the source of these funds.

In addition, operators of medium and large plants must obtain a bond based on total quantity of distilled spirits produced annually. For a plant which produces 20 to 50 million gallons of ethanol annually (40 to 100 million gallons of spirits), a maximum bond of \$200,000 is required (27 C.F.R. § 19.957). The bond is conditioned on payment of taxes. Additional ATF requirements are contained in 27 C.F.R. Part 19 (1980).

ATF also requires producers to file operations reports; maintain records showing the quantities of spirits produced, received, rendered unfit for beverage use, and used or removed from the premises; and maintain adequate security to prevent diversion of spirits.

3.6.12 Colorado's Joint Review Process

The Colorado Department of Natural Resources recently published a DOE-funded study entitled "Colorado's Joint Review Process for Major Energy and Mineral Resource Development Projects" (CJRP). The study provides an intergovernmental review procedure in which the project proponent and federal, state and local governments may voluntarily participate. Neither the proponent nor any government agency is legally required to participate; any agreements entered into may be terminated by either the proponent or the government agencies.

CJRP's goals include:

- encouraging industry to apply for permits concurrently as opposed to sequentially,
- encouraging early industry interaction with government and the public, and
- providing opportunities for public participation early in the planning stage.

CJRP is comprised of three stages. In Stage I, the project proponent first requests joint review. The state will accept a project for joint review only if it is "a major energy or mineral resource development project" (see Colorado Department of Natural Resources, Colorado's Joint Review Process 13 (1980)). The proponent must request joint review during the early stages of the project's development, i.e., in the initial phases of design and feasibility study.

After the state decides to accept a project for joint review, Stage II begins, which involves:

- establishing a joint review process team;
- preparing a decision schedule for the project;
- signing a joint agreement which commits federal, state and local governments to fully participate and details the responsibilities of each agency and the project proponent; and
- conducting public meetings which provide the public with an opportunity to express concerns raised by the proposed project and to identify issues that the reviewing agencies, and perhaps the proponent, should address.

During Stage III, the project decision schedule is implemented. The Joint Review Process Manual includes four model decision schedules for hypothetical energy or mineral resource development activities. Companies participating as of January 1981 included:

- 1) AMAX Inc. - Proposed Mt. Emmons Molybdenum Mine, Gunnison County;
- 2) Rio Blanco Oil Shale Company - Proposed demonstration oil shale open pit mine and surface report, Rio Blanco County;
- 3) Multi Mineral Corporation - Proposed underground nahcolite mine, Rio Blanco County; and
- 4) W.R. Grace and Co. - Proposed coal-to-methanol plant, Moffat County.

In conjunction with CJRP, the Colorado Department of Natural Resources prepared the Colorado Permit Directory for Energy and Mineral Resource Development (1980) to identify and describe permits the proponent must obtain from federal, state and local governments prior to exploring, extracting and processing energy and mineral resources in Colorado. The Colorado Gasohol Commission is currently compiling a similar directory specifically to assist gasohol producers.

3.6.13 Animal Feed Regulations

If grain is selected as the feedstock for the production of ethanol, grain residue suitable for use as animal feed will be one by-product of this process. Colorado has enacted a statute and issued regulations governing the production and the marketing of feed products. The Commercial Feed Law of 1979 (Colo. Rev. Stat., 1973, 35-1-106(g) as amended; and 35-60-109, as amended) vests in the Colorado Department of Agriculture, Division of Inspection and Consumer Services, authority to regulate the commercial feed area.

Under this grant of authority, the Department has promulgated regulations (Reg. No. 8CCR 1202-6) covering three major areas of concern: (1) registration, (2) adulteration and (3) misbranding of products. The statute and regulations generally follow the Uniform State Feed Bill which incorporates by reference appropriate provisions of the Federal Food, Drug, and Alcohol Act and official definitions of feed ingredients defined by the American Feed Control Officials (AAFCO).

The procedure for registration is fairly straightforward. Anyone distributing commercial feed in the State of Colorado (except customer-formula feed) must, on an annual basis, submit an application listing the feeds to be registered, labels for each feed, and a nominal fee dictated by tonnage. Because most states have adopted commercial feed laws, an alcohol producer would similarly have to register feed it distributes outside the state.

The information supplied on the feed label is also specified by regulation. Generally, the producer must disclose:

- (1) feed net weight or liquid volume;
- (2) product or brand name;
- (3) a guaranteed analysis of the feed;
- (4) the common name of each ingredient, unless a collective term is permitted;
- (5) the manufacturer's or distributor's name and address; and
- (6) precautionary statements and prescribed directions for use.

Prohibitions against and penalties for mislabeling or adulteration of commercial feeds demand strict quality control by the manufacturer and distributor of these products (Solar Energy Research Institute, November 1980). To ensure adherence to state mandates, the Colorado Department of Agriculture has the authority to inspect a manufacturer's feed samples, the ingredients, or the raw materials and to analyze them.

An alcohol feed plant properly designed and operated can minimize problems associated with regulatory compliance. The use of geothermal fluid injected as steam during the cooking process should cause no problems (e.g. concentration of mineral level) with adulteration or labeling since the injected steam will be introduced in a relatively pure form.

3.6.14 Occupational Safety and Health

Issues relating to worker health and safety are the province of the federal Occupational Safety and Health Administration (OSHA) (29 CFR 1901 et seq.). The states may enforce the provisions of OSHA if the Secretary of Labor certifies a state-submitted plan. Since Colorado has no such plan, OSHA, the federal agency, would govern the safety aspects of the San Luis Valley facility.

The primary potential threats to worker health and safety are explosion, exposure to toxic and corrosive chemicals. However, in an ethanol facility, adequate controls or mitigating measures are currently available to minimize the problem (see Solar Energy Research Institute, November 1980). According to a report prepared for the design of a power alcohol plant (Kentucky Agricultural Energy Company, undated) the products, co-products and raw materials used in a process similar to that proposed for San Luis Valley are not considered toxic or extremely hazardous to those exposed.

Nevertheless, if benzene is selected as the dehydrating agent after distillation, strict precautions must be taken in work areas during its use. OSHA regulations

limit the exposure to benzene to 10 ppm (8-hour, time-weighted average) to an acceptable ceiling concentration of 25 ppm or 50 ppm for a 10-minute period (29 CFR 1910.1000, Table Z-2).

A recent sampling program conducted at the Midwest Solvents plant revealed benzene concentrations in the low range of 2.7 to 59.4 ppm for the liquid streams. As these values are near the detection limit for benzene, they are assumed to have limited accuracy. Nevertheless, it is known that 27 gallons of benzene (approximately 1 gallon for every 5500 gallons of product ethanol) would be lost daily somewhere in the process for a 50 million gallon per year plant (Solar Energy Research Institute, November 1980).

There are also limits for workplace exposure for the finished ethanol product. The federal standard for ethanol is 1000 ppm (1900 mg/m³) (29 CFR 1910.1000 Table Z-1). To comply with the above-mentioned limits, OSHA requires the employer to determine and implement administrative or engineering controls whenever feasible. Alternatively, protective equipment or measures must be used to keep the exposure to air contaminants within bounds. Since the 1000 ppm standard represents a fairly high concentration, it is unlikely that the proposed facility would exceed these limits (pers. comm., Gribble, California OSHA, August 11, 1981).

3.6.15 Summary and Conclusions

A review of institutional constraints related to the development of a proposed ethanol facility utilizing geothermal energy in the San Luis Valley was undertaken. A data base of regulatory and environmental constraints imposed by federal, state and local governments was compiled. Additionally, regulations pertaining to industrial development were discussed.

Institutional constraints begin with the need for the operator to acquire rights for the operator to develop the geothermal resource, typically through a lease. Permits to drill wells on these leases are inextricably tied to the State of Colorado's system for protecting water rights. The system of water rights protection and acquisition was analyzed with a view toward development of the geothermal resource itself and the potential need for water in the ethanol process.

Local governmental controls affecting industrial development in Alamosa County, as well as the impacts of development on the community, were addressed. Environmental impacts were addressed pursuant to requirements of the National Environmental Policy Act. The permits associated with potential environmental impacts were described.

In conclusion, Colorado currently does not regulate some aspects of development of an ethanol facility to the same extent as other states (e.g. California). New industry is faced, however, with complex regulation at the federal level. Water is one resource the state does judiciously guard and regulate. A new facility seeking to appropriate large quantities of water for its operation may encounter difficulties. Nevertheless, the regional and local community appears to be motivated toward greater economic development in the San Luis Valley. An ethanol facility utilizing the agricultural resources of the region would contribute toward the area's economic goals.

SECTION 4

ETHANOL SYSTEM

4.1 GENERAL DESIGN CONSTRAINTS

For an ethanol plant that utilizes a feedstock mix, a reduction of capital costs can be realized if the feedstocks are of a similar nature. Agricultural supplies available in the largest quantities for ethanol production in the San Luis Valley are amylaceous materials (grains or potatoes). The amylaceous materials contain complex polysaccharides (starches) which are not directly subject to fermentation. After feed preparation, which includes cleaning, size reduction and slurry formation, a "cooking" or starch liquefaction stage is used to release the starch from the cells and break down the starch bonds. This step normally requires a pH of 6.5 for optimum enzymatic action. The pH of the mash can be adjusted with injection of sodium hydroxide or sulfuric acid. Heat and the enzyme alpha-amylase are added at this stage to achieve the desired results. After the starch is released, glucoamylase is added to break down the starch dextrins to produce glucose for fermentation.

Batch fermentation for ethanol production is normal industry practice. Batch fermentation is common to commercial operations because it assures minimum contamination and simple operation. Although progress has been made towards continuous fermentation, it has not yet been adapted to commercial size ethanol plants. Retention time for batch fermentation is approximately 40-60 hours for normal yields of glucose conversion to ethanol of 92 percent. Other by-products formed during the fermentation phase are carbon dioxide (CO_2), heavier weight alcohols, aldehydes and water. The CO_2 is released into the vapor space of the fermentation tanks, and is released to the atmosphere or compressed and sold. The other by-products are removed at later stages of processing, normally in the distillation and dehydration process steps. The fermentation process normally requires cooling to maintain the temperature of the mash at optimum conditions for the yeast. As the reaction proceeds, heat is released which is dissipated by circulating the mash through heat exchangers to reduce the bulk temperature of the mash. In order to prevent sterilization of the yeast culture, the mash must be maintained at a temperature below 32C (90F).

The DOE-funded studies which analyze the application of geothermal energy for ethanol production suggest both direct and indirect heating of the process stream. If the resource is hot enough, the geothermal fluid can be flashed to produce steam at temperatures required for the various process steps. If steam condensation is the

driving force for heat transfer in the heat exchangers, the heat transfer surface can be minimized. The main disadvantage to this approach would be the large quantities of geothermal fluid required to produce enough steam to provide process heat. The lower the temperature of the resource, the less steam can be produced at a specific temperature for each pound of geothermal fluid produced. Direct heating by steam injection would be most advantageous in the cooking process. If the geothermal fluid is to be used directly in the process stream, it should be flashed or otherwise cleaned to prevent the brine from contaminating the process stream.

Temperature requirements for the ethanol process are listed below in order of decreasing temperature.

1. Cooking
2. By-product dehydration
3. Distillation
4. Ethanol dehydration
5. Preheating steps

Continuous distillation can be clearly justified economically over batch distillation for plants over a capacity of 3785 liters (1000 gallons) per day due to the increased potential for heat cascading and reduced operator time. Since plant operation requires a flow of 9460-23,660 liters (2500-6250 gallons) per hour for 76-189 million liter (20-50 million gallon) annual capacity, continuous distillation will be used at the San Luis Valley Ethanol Plant. The feed for the distillation column will come straight from the fermentation surge tank which is filled during the emptying cycle from the fermentation tanks.

The design assumption for the ethanol plant is that the beer from the fermentation vats contains approximately 10 percent alcohol. After the distillation phase, the alcohol product stream is 95 percent ethanol by volume as it enters the dehydration column. Pentane has been found to be superior to either benzene or diethyl ether for the dehydration of aqueous ethanol on the basis of least cost per unit of ethanol produced (Black, 1980). When used as the entrainer, pentane provides complete recovery of dry ethanol as a bottom product from the azeotropic column. The "normal" entrainer used for industrial applications was the hydrocarbon benzene. Extractive distillation with gasoline has been found to be comparable in operating costs to pentane, so either of these dehydration agents would be applicable to San Luis Valley. Gasoline, although slightly more expensive, carries the added benefit of acting as a denaturant for the production of gasohol. Because pentane has not yet been successfully proven as a

dehydration agent on a commercial scale, benzene or gasoline should be used as the entrainer keeping with the philosophy of using conventional production techniques.

4.2 ALCOHOL PROCESSING

The major engineering concerns for adapting the ethanol production process to the utilization of geothermal energy are the temperatures and heat flows required for major process steps. This is directly associated with potential maintenance problems caused by corrosion or scaling because of the mineral constituents in the geothermal brine. Heat transfer will be adversely affected if solids deposition occurs within process piping. Any initial treatment of the brine to reduce corrosion within the plant may decrease the temperature of the fluid or reduce the amount of energy available in subsequent processing steps.

4.2.1 Cooking

The cooking process which liberates the starch molecules in corn or wheat from their cell walls is most efficient in terms of alcohol yield at temperatures above 153C (308F). Experience has shown that alcohol yield, which is the final criterion of the cooking process, is greatly increased for a given retention time by cooking at 153C (308F) as compared with 100C (212F) (Wilke, 1942). Low cooking temperatures, accompanied by longer retention times, can also achieve high yields; however, such a system would have a higher capital cost and might also require additional engineering.

There are several options to evaluate for the geothermal ethanol plant. One is to accept the reduced alcohol yield and use the geothermal direct heat to cook the mash at lower temperatures. Another would be to boost the temperature of the geothermal fluid with fossil fuel or to burn the fusel oils and light ends generated by the ethanol process. Although the higher weight alcohols can be reblended into the ethanol after dehydration without a deleterious effect on its combustion characteristics for gasohol, the light ends, such as aldehydes, can cause vapor lock in automobile engines. These combined process contaminants which are removed in the dehydration step can be burned to boost the temperature of the incoming geothermal fluid. This would eliminate a potential waste disposal problem of the light ends and contribute to solution of the cooking temperature problem. However, only 15 to 19 liters (4 to 5 gallons) of fusel oils and light ends are produced for every 3785 liters (1000 gallons) of anhydrous ethanol. These options merit further investigation once resource data is established for the San Luis Valley area.

4.2.2 Fermentation

The fermentation step is fairly straightforward and will not have to interface with the geothermal system, as fermentation is an exothermic process and normally requires cooling to maintain optimum conditions for yeast propagation and alcohol formation. However, in an area with cold winters like the San Luis Valley, heating might be required if the fermentation tanks are exposed to the weather. It isn't recommended this be done. Therefore, the major concern here is to obtain cooling water to dissipate the heat generated over the 40-60 hour retention time. Because of the regulations for water use in the San Luis Valley, wet cooling towers are not allowed if they result in a consumptive use of water for the overall plant (McFadden, 1981).

4.2.3 Alcohol Recovery

The distillation and dehydration columns will be the most sensitive area of the geothermal system adaptation. Normally the energy requirements for these columns are supplied by the condensation of steam in coils located in the base of the column. The condensation coils prevent the introduction of additional water into the dehydration process.

Some important restrictions will be placed on the design of the distillation and dehydration columns. Based on the initial evaluation of the geothermal reservoir, steam available for the ethanol plant will be low pressure steam. Optimally, both columns could operate with steam at approximately atmospheric pressure. In some designs, this condition increases steam requirements by as much as 50 percent. Low pressure steam use along with waste heat recovery will be incorporated in the design of the alcohol recovery equipment to minimize steam consumption.

4.2.3.1 Azeotropic Entrainers

The product of the distillation column is a mixture of alcohol and water, the ratio of the two components is dictated by column design. Since ethanol and water form an azeotropic mixture at an ethanol concentration of 95.6 percent, the remaining water must be extracted in a dehydration process step. One technique for removing the water involves the introduction of a third component to break the azeotrope. Benzene is a common hydrocarbon which has been used for this dehydration process step, but research on alternative hydrocarbon entrainers concludes that it is not the most energy-efficient (Mix, 1981).

Listed below are the reboiler energy requirements for the dehydration column adjusted to a constant ratio of reflux to minimum reflux of 1.2 for benzene, cyclohexane and pentane. All of the data are for feed to the dehydration column with an ethanol mole fraction of 0.826.

Table 4-1

ETHANOL DEHYDRATION ENERGY REQUIREMENTS

<u>Entrainer</u>	Dehydration Column Reboiler Energy Requirements	
	<u>(Btu/gal. Ethanol)</u>	<u>(Kcal/liter)</u>
Pentane	379-704	5,667-10,545
Cyclohexane	521-539	7800-8070
Benzene	759	11,355

The range of values for the energy requirements reflect primarily different theoretical assumptions. Benzene and cyclohexane systems operate essentially at atmospheric pressure. The temperature is determined by the boiling point of the benzene-ethanol and cyclohexane-ethanol azeotropes. The lower energy requirements for the cyclohexane system reflect primarily the lower mutual solubility of cyclohexane and water as compared with benzene and water.

A number of factors tend to help the pentane system which is operated at 40 psia base column pressure. Pentane has a significantly lower heat of vaporization than ethanol and water and somewhat lower than that for cyclohexane. The vaporization for the following liquids at 15°C is: pentane, 88.7 cal./g; ethyl alcohol, 204 cal./g; water, 539.6 cal./g; cyclohexane, 89.2 cal./g, benzene, 97.8 cal./g. Near the feed tray, where the limiting reflux conditions occur, the pentane concentration in the vapor is significantly higher than that for the cyclohexane in the cyclohexane system (nearly 0.8 mole fraction versus about 0.5 mole fraction).

The higher volatility of the pentane relative to cyclohexane and benzene results in an overhead vapor from the dehydration column which has a considerably higher entrainer concentration, reducing the energy requirements for stripping.

Of the three entrainers, benzene is the most difficult to separate from ethanol and pentane is the easiest to separate. However, since the efficiency of the pentane system depends on higher pressure steam that is not available at the San Luis Valley Ethanol Plant, the best choice for an entrainer would seem to be cyclohexane as that system can operate at atmospheric pressure, and requires significantly less heat than a dehydration column that uses benzene. The recommendation of this study is to

investigate the use of cyclohexane in the dehydration column when detailing the specifications for the column.

4.2.4 Katzen Distillation and Dehydration Process

An energy conservative distillation process developed by Raphael Katzen Associates requires only 2.11 kilograms of steam per liter (17.5 pounds for each gallon) of ethanol produced or approximately 1069 kCal/liter (16,000 Btu/gallon) of ethanol. The process is currently under patent application. This technique differs from the normal distillation process which can require 3.67 to 12.84 kilograms of steam per liter (30.6 to 107 pounds of steam per gallon) of ethanol to distill and dehydrate the aqueous alcohol mixture. The steam requirement varies depending on the temperature and the alcohol percentage of the feed to the distillation column.

The Katzen distillation process relies on waste heat recovery to optimize fuel use and ethanol production. For a dilute beer containing 7.1 percent alcohol by weight and 6.92 percent solids, the distillation process is as follows.

4.2.4.1 Distillation

The beer leaves the beer well at a temperature of 32°C (90°F) and undergoes a series of preheating steps before it enters the first stage of distillation. The energy for preheating the feed comes from the overhead vapors from the pressure stripper-rectifier and the overhead product of the dehydration tower. The overhead vapors from the pressure stripper-rectifier pass out at 121°C (250°F) at 3.5 kg/cm² (50 psig). These vapors are utilized as a source of heat by condensing in the reboilers for the dehydration column and the hydrocarbon stripper in addition to feed preheating. The product stream leaving the distillation column is 95 percent alcohol by weight and enters the dehydration tower.

Modifications to the distillation column will be required so that it can operate with steam provided at 105°C (221°F). This low steam temperature will result in less heat suitable for cascading than previously described for the Katzen Process. Waste heat recovery methods will be incorporated in the design to minimize the additional steam required to provide the necessary kCals (Btus).

4.2.4.2 Dehydration

The dehydration tower operates at atmospheric pressure and produces anhydrous motor fuel as a bottom product at 99.5 percent alcohol. A portion of the overhead product of the dehydration tower (a minimum boiling ternary azeotrope of hydrocarbon, alcohol and water) is condensed and used to preheat the feed to the distillation column. The rest of the vapor is subcooled by cooling water before passing into

the decanter. In the decanter, the subcooled liquid separates into two layers. The top hydrocarbon-rich layer is pumped back to the dehydration tower and the bottom layer goes to the hydrocarbon stripper.

4.2.4.3 Hydrocarbon Stripper

The bottom layer from the decanter goes to the hydrocarbon stripper which removes the alcohol and hydrocarbon from the water and recycles the hydrocarbon and alcohol to the dehydration column. The water from this process is then sent for wastewater treatment. The combined return of hydrocarbon from the decanter and the hydrocarbon stripper accounts for 99.98 percent of the alcohol (Raphael Katzen Associates, 1978).

4.2.4.4 Fusel Oils and Light Ends

The fusel oils, or heavier weight alcohols, tend to concentrate on a specific tray level in the distillation column. Thus concentrated, they are taken off as a side product and go to further processing to remove any residual alcohol. The light ends are removed by withdrawing a small purge from the total reflux stream passing back to the top tray of the pressure stripper-rectifier. The fusel oil and light ends must be removed because their presence would upset the equilibrium in the dehydration process.

4.3 SUMMARY

Because of the highly favorable energy balance of the Katzen process, this distillation and dehydration process or an adaptation that would accommodate steam pressure produced by the geothermal system is recommended for use at the San Luis Valley Ethanol Plant. The distillation column would be modified to operate at atmospheric pressure. Further process design and flow charts for the ethanol process and the geothermal system are detailed in Section 7, Conceptual Design. The techniques for energy conservation and waste heat utilization will be incorporated in the system design.

A summary of the initial design constraints for the engineering approach to the ethanol system, which are expanded in the Conceptual Design, Section 7, is listed below.

COOKING:

1. Alpha amylase enzyme for liquefaction
2. pH 6.5
3. Glucoamylase to break starch bonds

FERMENTATION:

1. Batch fermentation
2. 40-60 hours retention time
3. *Saccharomyces cerevisia* as yeast
4. pH 4.5

DISTILLATION:

1. Continuous distillation
2. Use of modified Katzen distillation process

DEHYDRATION:

1. Benzene or cyclohexane as dehydrating agent
2. The use of fusel oils and light ends as a possible fuel source

SECTION 5 GEOTHERMAL SYSTEM

5.1 INTRODUCTION

Geothermal fluid is the prime source of heat energy for the ethanol plant. The ethanol process can be adapted to utilize several temperature levels of steam. The crucial steam requirement is in the cooking process where temperatures of 130°C to 150°C are necessary to release the starch from the cell walls in an efficient manner. Mr. Mark Maggion of Miles Laboratory (Maggion, 1981) indicated that direct steam injection into the starch slurry was the only practical technique for heating the mash. Indirect heating through steam coils has been tried, but the viscosity of the mixture is so high that problems arise because the mixture clogs the heat exchangers.

The number of geothermal wells required for the plant will be dependent on the optimum capacity of the ethanol plant as determined by the economic analysis. The pipelines will be insulated to minimize energy losses in transportation of the geothermal fluid and the wells will be located at the minimum practical distance from the ethanol plant.

The geothermal fluid entering the plant will be flashed to 140°C (284°F) for the cooking process. The steam released from this flash chamber will be injected into the mash at the cooking stage. Geothermal steam should have no adverse effects on the ethanol process. Although the enzymes and yeast are sensitive to heavy metals and alpha-amylase is negatively effected by sodium EDTA, neither of these are expected to be contained in the San Luis Valley brine. The remaining fluid at 140°C will enter a second flash chamber, reduce the pressure to 1.2 bars (17.5 psia) and produce steam at 105°C (221°F). This geothermal steam will be used in the distillation columns to concentrate to an ethanol concentration in the inlet beer of 95.5 percent.

5.2 WELLFIELD DESIGN

An ethanol facility with a production of 189 million liters (50 million gallons) per year will require a geothermal brine supply of approximately 45,420 liters (12,000 gallons) per minute if the resource produces fluid which is a saturated liquid at 150°C (302°F) delivered to the plant. A proposed geothermal brine production-injection distribution system is illustrated in Figure 5-1. This system utilizes 28 production wells at 1628 liters (430 gallons) per minute each, and following established geothermal well engineering practices, 14 injection wells at 3256 liters (860 gallons) per minute each.

Geothermal Brine Production and Injection Distribution System for San Luis Valley Ethanol Plant

FIGURE 5-1

The production and injection islands are situated on the periphery of a square around the ethanol facility in order to minimize pipeline and insulation costs. The interconnecting pipelines are buried to avoid intrusion onto and interference with surface farmland and vehicular-pedestrian rights-of-way. The production pipelines are also insulated and encased to reduce heat loss.

A pictorial representation of the geothermal brine production and injection islands is shown in Figure 5-2. Each island's piping is above ground. The production island's piping is insulated and encased by an aluminum jacket to reduce heat loss due to convection.

The production island wellheads are spaced 23-30 meters (75-100 feet) apart with each well directionally drilled at about 15 degrees off vertical, well within the 30-45 degree angles routinely handled by directional drilling equipment. The wells will be drilled to a depth of 3050 to 3660 meters (10,000 to 12,000 feet) to yield eventual bottom hole horizontal separations of 800 meters (2600 feet). This distance is generally accepted as the minimum allowable to enable each production well to draw fluid from an undisturbed segment of the aquifer. The injection island wellheads are also spaced 23-30 meters (75-100 feet) apart, but the injection wells are directionally drilled to 1220-1830 meters (4000-6000 feet) to yield eventual bottom hole horizontal distances of 400 meters (1300 feet). The drilling angle will vary from 10-13 degrees off vertical, depending on the number of wells per island.

The investment required for wellfield development for a 189 million liters (50 million gallon) per year ethanol facility is shown in Table 5-1. The wellfield is divided into its component parts with the associated costs listed for each. All prices are based upon mid-year 1981 dollars. The cost for establishing an Underground Injection Control Monitoring Network, as required by the Safe Drinking Water Act of 1974, are also included. This Act was established to require states to formulate regulations to protect underground drinking water supplies from contamination of deep-well injection of toxic substances, as specified at 40 CFR, part 146. The material to be controlled "is any substance that would endanger the quality of the drinking waters by either causing adverse health effects or making the water unpalatable." The regulations outline specific well construction, operating, monitoring and reporting requirements.

Geothermal Brine Production and Injection Islands for San Luis Valley Ethanol Plant

**FIGURE
5-2**

Table 5-1

**SAN LUIS VALLEY, COLORADO
INVESTMENT REQUIRED FOR WELLFIELD DEVELOPMENT
FOR A 152 MILLION LITER (40 MILLION GALLON) PER YEAR
GEOTHERMAL-ETHANOL FACILITY**

	<u>Brine Production System</u>	<u>Brine Injection System</u>
Piping	\$ 730,512	\$1,073,568
Fittings	13,272	12,284
Valves	167,092	156,653
Insulation	1,091,260	12,120
Labor	83,936	104,876
Wells	50,680,000	7,000,000
Monitoring Network		280,000
Pumps	<u>2,520,000</u>	<u>756,000</u>
Subtotal:	\$55,286,072	\$9,395,501
Overall:	\$64,681,573	

1. Piping: Includes all carbon steel piping from ethanol facility to wellheads. The injection system piping cost is greater due to the additional 485 meter (1585 feet) interconnecting pipeline (see Figure 5-2).
2. Fittings: Includes all necessary carbon steel flanges, reducers, tees, elbows, and adapters.
3. Valves: Includes cast iron gate valves at each wellhead and a master gate valve for each island.
4. Insulation: Includes calcium silicate insulation and casing for brine production underground interconnecting pipelines, and production and injection island surface facilities.
5. Labor: Based upon the Richardson Construction Cost Trend Reporter Denver labor price of \$16.56 per hour.
6. Wells: Based upon current geothermal well costs of approximately \$1.81 million per production well and \$.5 million per injection well.

7. **Pumps:** The downhole production pump costs are from TRW-REDA Pump Company, Inc. The 28 pumps are each rated at 235 kilowatts (315 horsepower), and provides 1628 liters (430 gallons) per minute at 555 meters (1800 feet) at a 335 meter (1100 foot) setting depth. The design temperature is 177°C (350°F). The injection pump costs are from Goulds Pumps, Inc. These 14 pumps are each rated at 261 kilowatts provide (350 horsepower), 3255 liters (860 gallons) per minute at 320 meters (1050 feet) of head with a design temperature of 107°C (225°F).

5.3 HEAT EXCHANGE METHODS

Due to the possibility of a high total dissolved solids (TDS) content of the brine, it is recommended that flashed steam be used to heat the process stream. In addition to increasing the quality of the fluid, as most of the solids should remain in the liquid portion in the flash chamber, the actual heat transfer surface area can be kept to a minimum if steam condensation is used as the vehicle for effecting heat transfer. Some process steps, such as preheating the beer feed to the distillation column and other low temperature direct heat application processes, can use hot brine as an energy source. Should hot brine be used for heating, the heat exchangers must be straight-tube shell and tube units with brine flow in the tubes to permit ease of maintenance should descaling be required.

5.4 BRINE SUPPLY

All delivery lines from the production wells will be pressurized to prevent premature flashing in the pipeline. All of the supply lines will be insulated to minimize heat loss from the transmission pipelines. The brine will be delivered to the initial flash/separators through approximately 1.8 kilometers (5800 feet) of carbon steel pipe.

If steam is used for all process heating, flashing the fluid to produce the steam (which is relatively free of chemical and mineral contaminants) will reduce the flow rate of the heat transfer medium (i.e., geothermal fluid) to process equipment. For instance, if the geothermal fluid was delivered to the plant at 150°C (302°F) and flashed to two levels: 140°C (284°F) and 105°C (221°F), the quantities of geothermal steam and fluid would be as follows:

Based on 1000 kg (2200 pounds) of fluid at 150°C (302°F)

Steam

20.1 kg (44.2 pounds) of steam at 140°C (284°F)
65.0 kg (143.0 pounds) of steam at 105°C (221°F)

85.1 kg (187.2 pounds)

Geothermal Fluid

914.9 kg (2012.8 pounds) of fluid at 105°C (221°F)

Out of 1000 kilograms (2200 pounds) of 150°C (302°F) geothermal fluid, a combined total of 85.1 kilograms (187.2 pounds) of steam would be produced at these temperature levels. If the remaining geothermal fluid was not used for any process heat, 914.9 kilograms (2012.8 pounds) of fluid at 105°C (221°F) would be sent to brine treatment or reinjection.

Steam condensation requires the minimum heat transfer area and thus reduces equipment size and cost. Low temperature direct heat process uses should be identified to conserve the maximum amount of energy with the minimum number of production wells.

5.5 FLASH/SEPARATORS

The brine will be flashed in two stages in order to meet the steam specifications for the ethanol plant (Figure 5-3). The inlet raw brine will be dropped in pressure to 3.6 bars (52 psia) or 140°C (284°F) to provide steam for the jet cookers. The liquid from the first stage flash chamber will be flashed in the second flash/separator to a pressure of 1.2 bars (17.5 psia) or 105°C (221°F). This steam will be used in the distillation and dehydration process steps.

Because scaling in the flash/separators is expected to be a problem, two vessels will be used in parallel for each stage. Each flash/separator will be designed to handle 125 percent of the total brine flow thereby allowing one unit to be off-line for cleaning or maintenance while the other unit remains in service. This system redundancy is expected to assure continuous plant operation. Since most of the solids precipitation will be confined to the flash chambers, minimal scale deposition is expected on other pieces of process equipment.

Geothermal System Flow Diagram San Luis Valley Geothermal Alcohol Plant Section 1100

**FIGURE
5-3**

5.6 DIRECT HEAT PROCESS USES

After exiting the second stage flash separators, the geothermal brine can be utilized for direct heat process uses to extract the maximum amount of energy from the fluid before it is reinjected. There are many places in the ethanol process that require a relatively low temperature heat source. Many of the inlet feed streams to cooking, distillation and dehydration process steps could utilize geothermal direct heat to raise the temperature of the process stream. Geothermal fluid can be used in conjunction with recycled waste heat to preheat these process streams. A pump will be used to pressurize the exit brine from the second stage flash/separator units which will be piped through the preheating units.

5.7 BRINE CLEANUP

In order to maintain long-term reliability of the reinjection wells it may be necessary to treat the spent brine prior to reinjection to remove the suspended solids which could plug the reinjection wells. Brine treatment may also prevent changing the permeability and therefore useful service life of the reinjection formation. The spent brine from the flash separator may be supersaturated with respect to some mineral components, e.g., silica or heavy metals. The brine cleanup system is designed to produce an effluent that is stable at saturated levels of these minerals which would prevent plugging the strata with discrete suspended solids in the brine. A reactor clarifier was chosen as the main component of the proposed brine cleanup system as shown in Figure 5-4.

The reactor clarifier concentrates the solids in the inlet fluid by providing seed nuclei for the solids. This unit operates on the principle of solids-contact clarification where large volumes of sludge (10 to 15 times the volume of feed) are recirculated internally through a draft tube/impeller arrangement to a reaction well. Previously precipitated sludge recirculated in this manner comes in intimate contact with the feed stream in the reaction well, providing seed nuclei on which dissolved solids in the feed stream precipitate under controlled conditions of temperature, reaction time and solids concentration.

The resultant liquid/solid mixture flows from the reaction well into the clarification compartment where the liquid and solids are separated by gravity. Treated liquid overflows into collection launders at the upper surface of the unit. Rake arms are used to move the settled sludge to a center thickening core at the bottom of the tank where the thickened sludge is discharged by gravity or pumps.

WESTEC Services, Inc.

Spent Brine Cleanup System San Luis Valley Geothermal Alcohol Plant Section 1100

FIGURE
5-4

The liquid is treated further in a multimedia gravity filter prior to being pumped into the reinjection wells. The increased oxygen content of the reinjected fluid may accelerate corrosion in the injection pipeline and well casing. An allowance for this corrosion should be considered when specifying pipeline thickness. The sludge from the reactor clarifier is thickened in a gravity thickener and then dewatered in a filter press.

The recovered solids can be disposed of at a solids waste disposal site. This type of waste has been specifically excluded in the definition of hazardous wastes by 40 CFR § 261.4(b). (5) "Solid wastes which are not hazardous wastes. The following are not hazardous wastes: drilling fluids, produced waters, and other waste associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, while such constituents are not anticipated for the San Luis Valley, the presence of specific heavy metals in the recovered solids may generate a hazardous waste dumping problem.

SECTION 6

ECONOMIC EVALUATION

6.1 INTRODUCTION

The economic analysis presented in this section is directed toward a discussion of financial incentives for the development of a geothermal-ethanol plant and an analysis of the discounted cash flow rate of return (DCFROR) of producing ethanol using geothermal energy in the San Luis Valley. In addition, the sensitivity of the DCFROR to changes in the value of various expenses is analyzed. The capital cost estimate of the facility which is used in the cash flow analysis is developed in Section 7 of this report.

6.2 FINANCIAL INCENTIVES

Investment in an ethanol plant will be influenced by any major economic incentives designed to encourage capital formation. Because of its value as a synthetic fuel, ethanol plants are eligible for many of the financial benefits available to developers of alternative energy sources. These benefits include the energy investment tax credit and the normal business investment tax credit. Coupled with these financial considerations are additional inducements for the acceleration of geothermal development including the deductions for intangible drilling costs and reservoir depletion allowances.

6.2.1 Federal

Several policy changes at the federal level make many of the financial incentives for geothermal development, including federal funding and support, uncertain. Federally guaranteed loans were among the first victims of the budget trims for alternative energy. In a discussion of the proposed budget the following statement was made.

Loan guarantee commitments for Carter administration geothermal and biomass programs are reduced by a huge \$1.9 billion in fiscal '81. (Electric Power and Light)

The 96th Congress provided new programs for the stimulation of alcohol fuel production. Two new major laws were passed: The Alternative Fuels Production Appropriations Act, Pub. L. No. 96-126, Title II and The Energy Security Act, Pub. L. No. 96-294, The Biomass Energy and Alcohols Fuel Act of 1980, Title II, Pub. L. No. 96-294. The federal programs provided for in this legislation are geared to

increasing the nation's alcohol fuels production capacity. Other federal legislation favorable to the production of fermentation alcohol as fuel has been adopted including The Energy Tax Act, Pub. L. No. 95-618 and the Windfall Profits Tax Act of 1980, Pub. L. No. 96-223 which encourage continued development of ethanol production capacity.

6.2.1.1 Alternative Fuels Act

The Alternative Fuels Act, which set aside \$2.1 billion for the development of alternative fuels, appropriated \$100 million for cooperative agreements with non-federal parties, \$500 million for a reserve to cover any defaults from loan guarantees and \$1.5 billion for purchase commitments or price guarantees. A portion of these funds will be spent on alcohol fuel projects. The funding for the loan guarantees provided by this law may not materialize as the policy of the new administration relies on the private sector to fund alternative energy projects that are viable in the near-term. Biomass (alcohol) projects must be commercial scale, i.e., at least 3.8 million liters (1 million gallons) per year or its energy equivalent, to qualify for this funding.

6.2.1.2 Energy Tax Act of 1978, Crude Oil Windfall Profit Tax of 1980

Of the five acts which comprise the NEA, three have provisions aimed at increasing geothermal development. The first, the Energy Tax Act of 1978 (Pub. L. No. 95-618, November 9, 1978) authorizes intangible drilling cost deductions and a percentage depletion allowance for geothermal resources. The act also provides for a 10 percent business investment credit for certain types of alternative energy equipment (including geothermal energy equipment) with the exception of public utility property. In addition the Energy Tax Act allows for a refundable income tax credit to users of gasohol.

6.2.1.2.1 Business Investment Tax Credit

In 1962 tax laws were revised to alleviate some of the undesirable effects of income taxation on capital investment. One of these revisions involved shortening the estimated life of depreciable property, which has the advantage of allowing the taxpayer to write off a larger depreciation percentage in the early years when high income taxes coupled with low depreciation might normally be a deterrent to capital formation. The establishment of an investment tax credit allows businesses to deduct from their income taxes a stipulated percentage of qualifying investments. With certain exclusions, the eligible property includes tangible personal property subject to depreciation. Exclusions include property used by or leased to governmental units. The investment tax credit is a reduction of the tax assessed by the government rather than a reduction in the taxable income of the business.

The Energy Tax Act of 1978, which amended Section 46 of the Internal Revenue Code to provide for an additional investment tax credit for businesses utilizing geothermal equipment, is amended by the Windfall Profit Tax. As a result of the Windfall Profit Tax (Pub. L. No. 96-223), the present 10 percent energy investment credit for geothermal equipment has been increased to 15 percent and is extended from 1982 through 1985. By definition, all businesses, whether converting existing facilities to geothermal or installing new systems, can qualify for the tax credit. However, only new equipment qualifies. Assuming no alternate means of financing, this tax incentive alone would provide a stimulus for the proposed San Luis Valley project.

The business investment credit applies to "alternative energy property," including "equipment used to produce, distribute or use energy derived from a geothermal deposit, but only, in the case of electricity generated by geothermal power, up to (but not including) the transmission stage (I.R.C. sec. 48 (5) (3) (viii))." The credit is only 5 percent if the property is financed by tax-exempt industrial development bonds. The equipment must be depreciable and must have at least a three-year useful lifetime. The equipment must conform to standards required to be developed by the Department of Energy (DOE).

If energy property is also tangible personal property that qualifies for the regular investment tax credit, then both credits can be utilized. To qualify for the business investment credit, the equipment must be new and must be placed in service after September 30, 1978, and before January 1, 1983, or, if acquired by the taxpayer, the original use must begin during this period. Unlike most other investment credit property, energy property can qualify for the investment credit even if it is considered a structural component.

Energy property must meet quality and performance standards that are in effect at the time the equipment is placed in service (CCH, 1978, Revenue Act of 1978).

6.2.1.2.2 Intangible Drilling and Development Costs

1. Option To Expense Intangible Drilling Costs:

Under Internal Revenue Code section 263(c), a taxpayer may decide to deduct intangible drilling and development costs of geothermal wells. As amended by the Energy Tax Act of 1978, section 263(c) allows the taxpayer to deduct intangible drilling costs from taxable income in the year the costs were incurred as opposed to capitalizing them. Prior to the act, this option was available only to oil and gas well developers but became available to geothermal developers effective October 1,

1978. This may be the most important provision of the Act in terms of geothermal development as a whole since it permits an investor to elect to write off that portion of the investment which relates to the intangible drilling costs even though the well is productive (Eisenstat, Samuel M., 1978). Included under "intangible drilling and development costs" are: labor, fuel and power, materials and supplies, tool rental, truck and auto hire, repairs to drilling equipment and depreciation upon drilling equipment. In general, intangible drilling and development costs are those items which in themselves have no salvage value. The cost of these items, incurred during the drilling of wells and during the preparation of wells for production, would have to be capitalized if not for this elective treatment permitted under the Act. Once the election is made, it is binding for future years. Tax benefits resulting from the deduction of intangible drilling costs must be recaptured (I.R.C. section 1254(a)).

2. Application of "at risk" rules to geothermal deposits:

The Energy Tax Act also amends section 465(c) of the Code to provide that the amount of losses deducted in a year relating to a geothermal deposit cannot exceed the total amount the taxpayer is at risk with regard to the property at the end of the taxable year. This provision in effect eliminates the use of non-recourse financing to increase available deductions. The "at risk" limitations of section 465(c) are inapplicable to the business investment tax credit previously discussed.

3. Minimum tax on geothermal wells:

The Act amends section 57(a)(11) of the Code and provides that to the extent the taxpayer has "excess intangible drilling costs" which exceed his net geothermal income, the taxpayer will have preference income subject to the minimum tax. To a certain extent this minimum tax will have the effect of mitigating the benefits of the ability to expense intangible costs. Preference income serves as the possible basis for the minimum tax and it also adversely effects the maximum tax on earned income.

Excess intangible drilling costs result when the intangible costs expensed exceed the deduction allowed if the taxpayer capitalized the intangible costs on productive wells and amortized them on a straight line basis from the time of first production (or to the extent the expensed costs exceed what would have been available under cost depletion) (Eisenstat).

4. Recapture upon disposition of geothermal deposit at a gain:

In amending section 1254(a) of the Code, as previously mentioned, the Act provides that a taxpayer disposing of geothermal property at a gain

must recognize ordinary income, as opposed to capital gains, to the extent the intangible costs deducted exceed what would have been allowed had the intangible costs been capitalized and amortized on a straight line basis from the time the property went into production. This provision is intended to preclude converting ordinary income into capital gains (Eisenstat).

6.2.1.2.3 Percentage Depletion

Effective October 1, 1978, an amendment to section 613 of the Code provides that geothermal deposits are eligible for percentage depletion. The percentages are as follows:

<u>Taxable Year Beginning In</u>	<u>Percentage</u>
1980	22
1981	20
1982	18
1983	16
1984 (and thereafter)	15

The tax advantage of the percentage depletion allowance for geothermal reservoirs is that the taxpayer may deduct the statutory percentage from gross income each year the property produces income. By comparison, after the capital investment has been recovered, no further cost depletion deduction is allowed. Although the Code does not specifically require a natural resource to be extracted or severed from the land, a depletion deduction is not allowed without extraction (Reg. §1.611-1(b)(1)).

6.2.1.2.4 Excise Tax

The Energy Tax Act provides that gasohol is exempt from its 4-cents-a-gallon Federal excise tax on motor fuels sold after December 31, 1978 and before October 1, 1984. The Crude Oil Windfall Project Tax of 1980 extends the exemption through December 31, 1992.

The Windfall Profit Tax further states that straight alcohol sold at retail to one who uses it directly for use in an internal combustion engine is eligible for an income tax credit. The credit is 40 cents per gallon of alcohol of at least 190 proof, and 30 cents per gallon of alcohol of at least 150 proof but less than 190 proof.

6.2.2 State of Colorado

Two laws were passed in Colorado that provided financial incentives for alcohol production as a motor fuel. In addition to financial benefits, SB 80 credited a

nine-member board, the Colorado Gasohol Promotion Committee, to promote ethanol fuels. The board expires July 1, 1985.

6.2.2.1 HB 1135

HB 1135 exempts gasohol from 5 cents of the 7 cents per gallon state motor fuel tax. To be eligible gasohol must contain at least 10 percent ethyl or methyl alcohol produced in Colorado from agriculture or forest resources, petroleum coke, waste coke, or coal waste. HB 1607 extended a property tax reduction to these types of plants. The exemption expires July 1, 1985.

6.2.2.2 HB 1463

HB 1463 removed the population and gallonage ceilings of HB 1135 which were originally a 200,000 maximum population ceiling restriction and 76 million liters (20 million gallons). This legislation also requires all state and local government agencies and units to use gasohol in their vehicles when such fuel becomes available, provided this conversion does not require mechanical modifications of the vehicles.

The law also authorizes a temporary reduction for property tax purposes in an assessed evaluation for alcohol plants producing 13 million liters (2.5 million gallons) or less on decreasing scale basis.

6.2.3 Conclusion

The change of administration in 1981 makes many of the financial incentives, including federal funding and support, uncertain. Federally guaranteed loans were among the first victims of the budget trims for alternative energy. The changing attitude towards federal support relies on the private sector to invest in alternative energy programs that are commercially viable in the near-term.

Some aspects of pending legislation that might encourage plant construction is the proposed increase in business investment tax credits designed to stimulate capital formation. Another possible spur to development is a change in the depreciation schedules that would allow investors in the plant to write off the cost of capital equipment more quickly.

6.3 CONVENTIONAL FUELS FORECAST

The economic viability of this project will depend heavily on the price escalations of petroleum fuels. As a direct competitor with gasoline, ethanol must be an economic alternative as an automotive fuel in order to gain momentum as a petroleum substitute. Although the psychological benefits of reducing dependence on foreign oil suppliers and using a fuel less damaging environmentally may influence some

consumers, these attributes must be combined with a price comparable to gasoline before any significant segment of the population will use gasohol.

The major function of price forecasts for fossil fuels in this study is to evaluate the market potential of ethanol. If petroleum prices stabilize and agricultural commodities continue to escalate in price, the possible uses of fermentation ethanol as a fossil fuel replacement are limited. However, if petroleum prices continue their skyward climb, ethanol could become an attractive alternate fuel in the near-term.

Conventional fuel forecasts for refined petroleum products (fuel oil and gasoline) are crucial in determining the possible outcome of this financial venture. Petroleum producers, for the most part, have discontinued the practice of publishing price forecasts due to the unpredictable nature of the price increases of crude oil. The final economic assessment models ethanol price escalations independent of general inflation in order to determine the rate of return of a geothermal ethanol production facility.

The major requirement of energy derived from fossil fuel sources for the plant is electricity to power pumps, compressors and agitators. The resource temperature at San Luis Valley is not expected to be in a range that could support economical electrical generation, so electricity purchased from the local utility will be used at the ethanol plant. The cost of electricity in 1981 dollars was \$.041/kw-hr. Escalation rates for energy were assumed to be the same as general inflation for the economic analysis.

6.4 PRICE INDICES

Price indices were used to gather some current equipment prices based on cost estimating guidelines, equipment prices from other projects and vendor data. The extrapolation of prices over an extended period are at best limited in accuracy. The price index is a statistical average and suffers from all the disadvantages of averages. However, these indices are meant to serve as guides only in estimating plant costs for a "typical" process involving no radical revisions to known technology which is directly applicable to the San Luis Valley Ethanol Plant.

6.4.1 Chemical Engineering

Prices for processing plants can be adjusted to reflect changes in the costs of four major components: equipment, machinery and supports; construction labor; buildings (material and labor); and engineering and manpower. These cost categories are the basis for a Chemical Engineering Price Index that originated in 1963 (Arnold and Chilton, 1963), which predicts the increases for chemical plant costs. This composite index uses commodity-price statistics from the U.S. Bureau of Labor Statistics (BLS) in

the U.S. Department of Labor. The single commodity indices are combined into larger groups of indices that include the prices of 155 individual commodities of particular interest to the chemical process industries. "A research study of process industry companies, equipment manufacturers, contractors and consultants indicated that the agreement between total index values was extremely close and the differences between indexes in the chemical process industries were too minor to justify a series of multiple indexes" (Arnold and Chilton, 1963).

Included in the engineering and manpower price estimations are BLS annual surveys of salaries of engineers, draftsmen, clerical and administrative employees from which trends in earnings for the engineering-services component can be drawn. For engineers, independent data from the Engineers Joint Council and the National Society of Professional Engineers are combined to obtain the most accurate earning trends for engineers.

One of the important components of the Chemical Engineering Index is a correction of wage and earning rates for changes in productivity. This adjusts price trends to reflect the output of real product per man-hour over the projected time period. Technology advances in industry would build in an "upward bias" (Arnold and Chilton, 1963) for all cost indices that have labor rates as components.

6.4.2 Marshall and Swift

The Marshall and Swift (M&S) price index predicts capital equipment costs. This economic indicator is designed to trace installed equipment costs. Twelve specific industries comprise the M&S index. This index was designed for use in plotting cost trends for equipment. Most indices represent reproduction costs. They do not account for any major advances in process technology, (Norden, 1969) only replacement costs.

6.5 GEOTHERMAL - ETHANOL PLANT ECONOMIC ANALYSIS

The economic analysis of a geothermal-ethanol plant was conducted using discounted cash flow rate of return (DCFROR) calculations of producing ethanol using geothermal energy in the San Luis Valley. These calculations were used to generate generic curves of rate of return as a function of total project cost. These generic curves are defined solely from the basic economic criteria that were developed and therefore are not site-specific and can be applied in evaluating many geothermal-ethanol plant development opportunities.

The economic criteria used in conducting the base case analysis are listed in Table 6-1. Due to the diversity of tax treatment between a geothermal resource

Table 6-1

**ECONOMIC CRITERIA FOR GEOTHERMAL-ETHANOL
PLANT ANALYSIS BASE CASE**

<u>Economic/Financial Variable</u>	<u>Geothermal-Ethanol Plant</u>	<u>Geothermal Resource Development</u>
Capacity Factor	75 percent	75 percent
Ethanol, \$/Liter (\$/Gal)	0.48 (1.80)	NA
O&M Cost, \$/yr	6 percent of initial capital	10 percent of drilling and surface facilities
Royalty	1 percent of annual expenses	10 percent of gross revenue
Electricity, \$/kWh	.041	.041
Ethanol Escalation	10 percent	NA
Combined State and Federal Tax Rate	51 percent	51 percent
Depreciation	5 year ACRS	5 year ACRS
Inflation Rate	7 percent	7 percent
Construction Loan Rate	14 percent	NA
Project Financing Loan Rate	12 Percent	NA
Debt Financing Period	15 years	NA
Debt/Equity Ratio	75/25	0/100
Taxes and Insurance	2 percent of capital	2 percent of capital
Project Life	20 years	20 years
Tax Credits	10 Percent ITC 15 Percent ETC	10 percent ITC 15 percent ETC
Internal Rate of Return	20 Percent DCFROR Minimum	20 percent DCFROR Minimum
Depletion Allowance	NA	15 percent (Revenue minus royalty). Maxi- mum 50 % of taxable income.
Intangible Drilling Costs	NA	75 percent

developer and a geothermal resource end-user, the analysis was divided into two parts, geothermal resource development and geothermal-ethanol plant. The economic criteria for each part of the analysis are listed in Table 6-1. The financial incentives utilized in the analysis are also listed in Table 6-1. A DCFROR calculation based on a 25-year life-cycle cost was performed on each part of the analysis. This calculation assumes a scenario of 5 years to complete resource exploration, confirmation, drilling, engineering, construction, and start-up, beginning in 1981, followed by 20 years of firm operations, beginning in 1986. Utilizing the aforementioned 25-year scenario, the economic criteria listed in Table 6-1 and an assumption of the division of total resource development costs between exploration, drilling and surface facilities (assumed to be 12 percent, 80 percent and 8 percent respectively) a family of curves were defined, shown in Figure 6-1, which relate the total cost of geothermal development (in dollars per liter of ethanol plant capacity) to the cost of the geofluid (in mills per liter of ethanol produced) as a function of the percent DCFROR, in 1981 dollars.

For the purpose of our analysis, the capital cost estimate developed in Section 5.2, Wellfield Design, was utilized to determine a reasonable assumption for the total cost per liter of ethanol plant capacity associated with resource development. This cost estimate of 64.7 million includes costs for drilling and surface facilities for a 152 million liter (40 million gallon) per year geothermal-ethanol facility. The exploration costs, which were estimated to be 8.8 million for a geothermal field of this size, bring the total geothermal development cost to 73.5 million, in 1981 dollars. For a 152 million liter (40 million gallon) per year ethanol plant, this resource development cost equates to \$0.49 per liter (\$1.84 per gallon) of ethanol plant capacity. Entering Figure 6-1 at \$0.49 per liter (\$1.84 per gallon) of ethanol plant capacity and assuming a minimum DCFROR requirement of 20 percent (indicated as base case on Figure 6-1) yields a geofluid cost to the ethanol plant of 248 mills per liter (939 mills per gallon) of ethanol produced, in 1981 dollars. With an assumed 1981 selling price for ethanol of \$0.48 per liter (\$1.80 per gallon), this means that approximately 52 percent of the ethanol selling price will be required to pay for the cost of the geofluid. The cash flow statement for the geothermal resource development base case is shown in Table 6-2.

In a similar manner to the resource development analysis, an analysis of DCFROR for a geothermal-ethanol plant was performed utilizing the aforementioned 25-year scenario, the economic criteria listed in Table 6-1, along with estimates of the costs of feedstock, yeast, dehydration agent, and electrical power and of the value of plant by-products. A plant utilizing a 100 percent barley feedstock was assumed in

Geothermal Resource Development
Effect of Total Cost and Geofluid Cost on DCFROR

**FIGURE
6-1**

TABLE 6-2
GEOHERMAL RESOURCE DEVELOPMENT
BASE CASE CASH FLOW STATEMENT
(\$1000)

UNIT COST, \$/GAL	1.837	INCR TAX RATE, %/100	0.51
PLANT SIZE, MGAL	40.0	DEPRECIATION LIFE	5
INSTALLED COST, \$	73479	INFLATION MULT	1.07
CAPACITY FACTOR, %	0.75	CONST LOAN RATE, %	14.0
GEO COST, \$/GAL	939.0	CAP LOAN RATE, %	12.0
ORM COST, \$/YR	6468	CAP LOAN TERM, YRS	20
ROYALTY, %FUEL	10	PCT CAPT FINANCED	0
POWER PRICE, \$/KWH	0.0	INSUR. PCT OF CAPT	2.0
EXPLORATION COST	8797	PROJECT EQUITY	73479
DRILLING COST	57680	DEPRECIABLE FRACTION	0.892
SURFACE FACIL. COST	7002	INT RATE FOR NPV	0.200

YEAR	1	2	3	4	5	6	7	8	9	10	11	12	13
	1981	1982	1983	1984	1985								
REVENUE:													
ENERGY SALES	0.00	0.00	0.00	0.00	0.00	39509.88	42275.57	45234.86	48401.30	51789.40	55414.65	59293.68	63444.24
OTHER INCOME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE	0.00	0.00	0.00	0.00	0.00	39509.88	42275.57	45234.86	48401.30	51789.40	55414.65	59293.68	63444.24
EXPENSES:													
INTANGIBLE DRILL CO	12112.80	0.00	0.00	19078.33	20413.81	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ORM COSTS	0.00	0.00	0.00	2377.15	4239.25	9071.99	9707.02	10386.52	11113.57	11891.52	12723.93	13614.60	14567.63
TAXES & INSURANCE	323.01	345.62	369.81	990.23	1695.70	1814.40	1941.40	2077.30	2222.71	2378.30	2544.79	2722.92	2913.53
DEPRECIATION	0.00	0.00	0.00	0.00	0.00	1187.87	1742.21	1663.02	1663.02	1663.02	0.00	0.00	0.00
INTEREST COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROYALTIES	0.00	0.00	0.00	0.00	0.00	3950.99	4227.56	4523.49	4840.13	5178.94	5541.47	5929.37	6344.42
TOTAL EXPENSES	12435.81	345.62	369.81	22445.71	26348.76	16025.24	17618.20	18650.33	19839.44	21111.79	20810.18	22266.89	23825.57
INCOME LESS EXPENSES	-12435.81	-345.62	-369.81	-22445.71	-26348.76	23484.64	24657.37	26584.54	28561.87	30677.61	34604.47	37026.79	39618.66
DEPLETION ALLOWANCE	0.00	0.00	0.00	0.00	0.00	5333.83	5707.20	6106.71	6534.18	6991.57	7480.98	8004.65	8564.97
INCOME BEFORE TAXES	-12435.81	-345.62	-369.81	-22445.71	-26348.76	18150.81	18950.17	20477.83	22027.69	23686.04	27123.50	29022.14	31053.69
TAXES	-6342.26	-176.27	-188.60	-11447.31	-13437.87	9256.91	9664.59	10443.69	11234.12	12079.88	13832.98	14801.29	15837.38
MINIMUM TAX	2768.26	0.00	0.00	4578.85	5077.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INCOME AFTER TAXES	-8861.81	-169.35	-181.21	-15577.24	-17988.64	8893.89	9285.58	10034.14	10793.57	11606.16	13290.51	14220.85	15216.31
CASH ADJUSTMENTS													
EXPLORATION EXPENSE	-8269.18	-470.64	-100.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANGIBLE DRILLING	-4037.60	0.00	0.00	-6359.44	-6804.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPLETION	0.00	0.00	0.00	0.00	0.00	5333.83	5707.20	6106.71	6534.18	6991.57	7480.98	8004.65	8564.97
DEP-PRIN	0.00	0.00	0.00	0.00	0.00	1187.87	1742.21	1663.02	1663.02	1663.02	0.00	0.00	0.00
CAPITAL EXPENSE	0.00	0.00	0.00	-4288.88	-4589.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITC	0.00	0.00	0.00	929.40	994.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	-21168.59	-639.99	-281.92	-25296.16	-28387.89	15415.60	16735.00	17903.87	18990.77	20260.75	20771.49	22225.50	23781.28

TABLE 6-2 (CONTINUED)
GEOHERMAL RESOURCE DEVELOPMENT
BASE CASE CASH FLOW STATEMENT
(\$1000)

YEAR	14	15	16	17	18	19	20	21	22	23	24	25
REVENUE:												
ENERGY SALES	67885.33	72637.31	77721.92	83162.45	88983.82	95212.69	101877.58	109009.01	116639.64	124804.42	133540.73	142888.58
OTHER INCOME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL REVENUE	67885.33	72637.31	77721.92	83162.45	88983.82	95212.69	101877.58	109009.01	116639.64	124804.42	133540.73	142888.58
EXPENSES:												
INTANGIBLE DRILL CO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ORM COSTS	15587.36	16678.47	17845.97	19095.19	20431.85	21862.08	23392.42	25029.89	26781.99	28656.72	30662.70	32809.08
TAXES & INSURANCE	3117.47	3335.89	3569.19	3819.04	4086.37	4372.42	4678.48	5005.98	5356.40	5731.34	6132.54	6561.82
DEPRECIATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INTEREST COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ROYALTIES	6788.53	7263.73	7772.19	8316.25	8898.33	9521.27	10187.76	10900.90	11663.96	12480.44	13354.07	14288.86
TOTAL EXPENSES	25493.36	27277.90	29187.35	31230.47	33416.60	35755.76	38258.67	40936.77	43802.35	46868.51	50149.31	53659.76
INCOME LESS EXPENSES	42391.97	45359.41	48534.57	51931.98	55567.22	59456.93	63618.91	68072.24	72837.30	77935.91	83391.42	89228.82
DEPLETION ALLOWANCE	9164.52	9806.04	10492.46	11226.93	12012.82	12853.71	13753.47	14716.22	15746.35	16848.60	18028.00	19289.96
INCOME BEFORE TAXES	33227.45	35553.37	38042.11	40705.05	43554.41	46603.22	49865.44	53356.02	57090.94	61087.31	65363.42	69938.86
TAXES	16946.00	18132.22	19401.47	20759.58	22212.75	23767.64	25431.37	27211.57	29116.38	31154.53	33335.34	35668.82
MINIMUM TAX	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INCOME AFTER TAXES	16281.45	17421.15	18640.63	19945.48	21341.66	22835.58	24434.07	26144.45	27974.56	29932.78	32028.08	34270.04
CASH ADJUSTMENTS												
EXPLORATION EXPENSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TANGIBLE DRILLING	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DEPLETION	9164.52	9806.04	10492.46	11226.93	12012.82	12853.71	13753.47	14716.22	15746.35	16848.60	18028.00	19289.96
DEP-PRIN	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPITAL EXPENSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NET CASH FLOW	25445.97	27227.19	29133.09	31172.41	33354.48	35689.29	38187.54	40860.67	43720.91	46781.38	50056.07	53560.00

generating Figure 6-2, which shows the effects of total plant cost, in dollars per liter (gallon) of ethanol plant capacity and geofluid cost, in mils per liter (gallon) of ethanol produced, on DCFROR. Cost estimates for consumables expensed in the ethanol process, in 1981 mils per liter (gallon) of ethanol produced include: feedstock, 345 (1304); yeast, 4 (16); dehydration agent, 4 (16); electricity, 20 (75); and for saleable by-products, 206 (778). Including the estimated cost for geofluid of 248 mils per liter (939 mils per gallon) of ethanol produced from Figure 6-1, shows that even the basic expenses of producing ethanol exceed the market price for the product in 1981 dollars. It is only the marketability of the process by-products that makes this geothermal-ethanol plant cost-effective.

For the purpose of our analysis, the capital cost estimates developed in Section 7.12, Cost Estimate, were utilized to determine a reasonable assumption for the total plant cost per liter (gallon) of ethanol plant capacity. A cost estimate of \$0.47 per liter (\$1.78 per gallon) of ethanol plant capacity was selected as being representative of the range of plant sizes considered. Entering Figure 6-2 at \$0.47 per liter (\$1.78 per gallon) of ethanol plant capacity and using the estimated geofluid cost of 248 mils per liter (939 mils per gallon) of ethanol produced yields an estimated DCFROR of 30 percent for a feedstock of 100 percent barley.

An evaluation of the effect of other feedstocks on the DCFROR was conducted as a function of ethanol plant cost per liter (gallon) of plant capacity and the results appear in Figure 6-3. This analysis was made using either corn, wheat or barley feedstock. Corn was included because imported corn is available at lower cost than local wheat. The feedstock prices used in the analysis are as follows:

- corn - \$99.43 per cubic meter (\$3.50 per bushel)
- wheat - \$106.53 per cubic meter (\$3.75 per bushel)
- barley - \$76.70 per cubic meter (\$2.70 per bushel)
- potatoes - \$36.27 per metric ton (\$8.00 per CWT)

Potato feedstock alone was not analyzed at this point because it was recognized that for potatoes the ethanol yield per unit weight is on the order of one-fourth that of the grains. Potatoes yield 0.12 liters per kilogram (1.4 gallons per CWT) as compared to 0.41 liters (5 gallons) for the same weight of grain. This, coupled with potatoes higher cost rule them out as a single feedstock. However, since potatoes are a net water producer it is highly desirable to use a mix of potatoes with the grain feedstocks to reduce water consumption. Ideally, 12 percent or more ethanol production from potatoes would make the plant a net water producer.

Geothermal Ethanol Plant
Effect of Plant Cost and Geofluid Cost on DCFRO

**FIGURE
6-2**

Geothermal Ethanol Plant
Effect of Plant Cost and Feedstock on DCFRROR

**FIGURE
6-3**

Entering Figure 6-3 at a plant cost of \$0.47 per liter (\$1.78 per gallon) of ethanol plant capacity shows that the 100 percent wheat and 100 percent corn feedstock plants cannot meet the minimum 20 percent DCFROR requirement, while the 100 percent barley plant again would yield a 30 percent DCFROR under the assumptions stated in Table 6-1. From Figure 6-3 it can be inferred that ethanol can be produced at a competitive price using barley and a small potato mix (2 to 3 percent) but not in a net water producing configuration. Although small amounts of potatoes can be used as feedstock the profitability is very quickly lost as the percentage of potatoes in the feedstock increases.

For the purposes of the sensitivity analysis, a base case for the geothermal-ethanol plant was selected at a plant cost of \$0.47 per liter (\$1.78 per gallon) of ethanol plant capacity and a 20 percent DCFROR, which equates to a feedstock price of 374 mils per liter (1416 mils per gallon) of ethanol produced, approximately 8.6 percent higher than the cost of 100 percent barley feedstock. The cash flow statement for the geothermal-ethanol plant base case is shown in Table 6-3.

6.6 GEO THERMAL - ETHANOL PLANT DCFROR SENSITIVITY ANALYSIS

A sensitivity analysis was conducted on the geothermal resource development base case identified in Figure 6-1. The results of that analysis appear in Figure 6-4. Each cost variable in the base case was individually varied through a range of ± 50 percent and the corresponding percent DCFROR was calculated. From this analysis it can be seen that costs for operation and maintenance, exploration, surface facilities, insurance, and royalties along with the income tax rate have a relatively small impact on the overall percent of DCFROR. While on the other hand, costs for total development and drilling along with the general inflation rate, resource capacity factor, and the price charged for the geofluid have a more significant impact on the percent of DCFROR. Even so, the overall sensitivity of the percent DCFROR to changes in geothermal resource development cost variables is relatively low. For example, a 40 percent reduction in drilling costs, the single largest development expense, will only result in roughly a 5 percent increase in the percent of DCFROR.

A similar sensitivity analysis was conducted on the geothermal-ethanol plant base case identified in Figure 6-3. The results of that analysis appear in Figure 6-5. Again, each cost variable in the base case was individually varied through the same range and the resulting percent DCFROR calculated. From this analysis, it can be seen that costs for operations and maintenance, electricity, insurance, royalties, yeast and

UNIT COST, \$/GAL	1.78	ETHANOL ESCAL RATE	1.10
PLANT SIZE, MGAL/YR	40.0	INCR TAX RATE, %/100	0.51
INSTALLED COST	\$71120	DEPRECIATION LIFE	5
CAPACITY FACTOR, %	0.750	INFLATION MULT	1.07
ETHANOL PRICE, \$/GAL	\$1.80	CONST LOAN RATE, %	14.0
O&M COST, \$/YR	\$4267	CAP LOAN RATE, %	12.0
ROYALTY, KATZEN %	1.0	CAP LOAN TERM, YRS	15
FEEDSTOCK COST, \$/YR	\$56622	PCT CAPT FINANCED	75
YEAST COST, \$/YR	\$623	INSUR. PCT OF CAPT	2.0
DEHY AGENT, \$/YR	\$653	PROJECT EQUITY	27118
ELECTRIC COST, \$/YR	\$2986	DEPRECIABLE FRACTION	0.892
BY-PRODUCTS, \$/YR	\$31115	INT RATE FOR NPV	0.200
GEOTHERMAL, MIL/GAL	939		
PROJECT DEBT	81353		

TABLE 6-3
GEOTHERMAL-ETHANOL PLANT
BASE CASE CASH FLOW STATEMENT
(\$1000)

YEAR	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	11	12	13
EXPENSES:													
FEEDSTOCK	0	0	0	0	0	68393	75232	82755	91031	100134	110147	121162	133278
YEAST	0	0	0	0	0	753	828	911	1002	1102	1212	1333	1466
DEHYDRATION AGENT	0	0	0	0	0	789	868	954	1050	1155	1270	1397	1537
OPS&MAINTENANCE	0	0	0	0	0	5985	6404	6852	7332	7845	8394	8982	9611
ELECTRICAL	0	0	0	0	0	3141	3361	3596	3848	4117	4405	4714	5044
GEOTHERMAL ENERGY	0	0	0	0	0	39510	42276	45235	48401	51789	55415	59294	63444
TAXES&INSURANCE	0	0	0	0	0	1975	2135	2284	2444	2615	2798	2994	3204
OVERHEAD	0	0	0	0	0	3990	4269	4568	4888	5230	5596	5988	6407
INTEREST	0	0	0	0	0	9762	9500	9207	8879	8511	8099	7637	7120
DEPRECIATION	0	0	0	0	0	14513	21286	20319	20319	20319	0	0	0
ROYALTIES	0	0	0	0	0	1391	1567	1675	1803	1943	1892	2059	2240
TOTAL EXPENSES	0	0	0	0	0	150221	167725	178356	190996	204760	199229	213359	233351
REVENUE:													
BY-PRODUCTS	0	0	0	0	0	37583	41342	45476	50023	55026	60528	66581	73239
ETHANOL	0	0	0	0	0	86968	95664	105231	115754	127329	140062	154068	169475
TOTAL REVENUES	0	0	0	0	0	124551	137006	150706	165777	182355	200590	220649	242714
INCOME:													
GROSS INCOME	0	0	0	0	0	-25670	-30719	-27650	-25218	-22405	1361	5090	9363
INCOME TAXES	0	0	0	0	0	0	0	0	0	0	694	2596	4775
NET INCOME	0	0	0	0	0	-25670	-30719	-27650	-25218	-22405	667	2494	4588
CASH SOURCES:													
NET INCOME	0	0	0	0	0	-25670	-30719	-27650	-25218	-22405	667	2494	4588
TAX BENEFIT	0	0	0	0	0	13092	15667	14101	12861	11426	0	0	0
ITC	0	0	0	0	0	11932	11932	0	0	0	0	0	0
DEPRECIATION	0	0	0	0	0	14513	21286	20319	20319	20319	0	0	0
ACCOUNTS PAYABLE	0	0	0	0	0	10076	879	951	1037	1131	1216	1343	1465
TOTAL CASH	0	0	0	0	0	23942	19045	7722	8999	10471	1883	3837	6053
CASH USES:													
DOWN PAYMENT	0	0	0	13559	13559	0	0	0	0	0	0	0	0
DEBT RETIREMENT	0	0	0	0	0	2182	2444	2737	3066	3434	3846	4307	4824
ALCOHOL INVENTORY	0	0	0	0	0	6957	696	765	842	926	1019	1120	1233
ACCOUNTS RECEIVABLE	0	0	0	0	0	6957	696	765	842	926	1019	1120	1233
ALCOHOL	0	0	0	0	0	6957	696	765	842	926	1019	1120	1233
BY-PRODUCT	0	0	0	0	0	3007	301	331	364	400	440	484	533
TOTAL CASH USES	0	0	0	13559	13559	19104	4136	4599	5113	5686	6323	7033	7822
CASH FLOW:	0	0	0	-13559	-13559	4839	14909	3123	3886	4785	-4440	-3195	-1769

TABLE 6-3 (CONTINUED)
GEOHERMAL-ETHANOL PLANT
BASE CASE CASH FLOW STATEMENT
(\$1000)

YEAR	14	15	16	17	18	19	20	21	22	23	24	25
EXPENSES:												
FEEDSTOCK	146606	161266	177393	195132	214646	236110	259721	285693	314263	345689	380258	418284
YEAST	1613	1774	1952	2147	2362	2598	2858	3143	3458	3804	4184	4602
DEHYDRATION AGENT	1691	1860	2046	2250	2475	2723	2995	3295	3624	3987	4385	4824
OPS&MAINTENANCE	10283	11003	11773	12597	13479	14423	15432	16513	17669	18905	20229	21645
ELECTRICAL	5397	5775	6179	6611	7074	7569	8099	8666	9273	9922	10616	11360
GEOHERMAL ENERGY	67885	72637	77722	83162	88984	95213	101878	109009	116640	124804	133541	142889
TAXES&INSURANCE	3428	3668	3924	4199	4493	4808	5144	5504	5890	6302	6743	7215
OVERHEAD	6856	7335	7849	8398	8986	9615	10288	11008	11779	12604	13486	14430
INTEREST	6541	5893	5167	4354	3443	2422	1280	0	0	0	0	0
DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	0
ROYALTIES	2438	2653	2888	3145	3425	3731	4064	4428	4826	5260	5734	6252
TOTAL EXPENSES	252738	273865	296893	321997	349367	379212	411760	447261	487420	531277	579176	631500
REVENUE:												
BY-PRODUCTS	80563	88619	97481	107229	117952	129748	142722	156995	172694	189963	208960	229856
ETHANOL	186423	205065	225571	248129	272941	300236	330259	363285	399613	439575	483532	531886
TOTAL REVENUES	266986	293684	323053	355358	390894	429983	472981	520280	572308	629538	692492	761741
INCOME:												
GROSS INCOME	14248	19819	26159	33361	41527	50771	61222	73019	84887	98262	113316	130241
INCOME TAXES	7267	10108	13341	17014	21179	25893	31223	37240	43292	50114	57791	66423
NET INCOME	6982	9711	12818	16347	20348	24878	29999	35779	41595	48148	55525	63818
CASH SOURCES:												
NET INCOME	6982	9711	12818	16347	20348	24878	29999	35779	41595	48148	55525	63818
TAX BENEFIT	0	0	0	0	0	0	0	0	0	0	0	0
ITC	0	0	0	0	0	0	0	0	0	0	0	0
DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	0
ACCOUNTS PAYABLE	1597	1742	1900	2073	2262	2469	2695	2942	3213	3508	3832	4186
TOTAL CASH	8579	11453	14718	18420	22611	27347	32694	38722	44808	51657	59357	68004
CASH USES:												
DOWN PAYMENT	0	0	0	0	0	0	0	0	0	0	0	0
DEBT RETIREMENT	5403	6052	6778	7591	8502	9522	10645	0	0	0	0	0
ALCOHOL INVENTORY	1356	1491	1641	1805	1985	2184	2402	2642	2906	3197	3517	3868
ACCOUNTS RECEIVABLE												
ALCOHOL	1356	1491	1641	1805	1985	2184	2402	2642	2906	3197	3517	3868
BY-PRODUCT	586	645	709	780	858	944	1038	1142	1256	1382	1520	1672
TOTAL CASH USES	8701	9679	10768	11980	13330	14833	16507	18426	20669	23375	26533	30108
CASH FLOW:	-122	1775	3951	6440	9281	12514	16187	22296	37739	43881	50804	58596

Geothermal Resource Development
Sensitivity of DCFROR to Cost Variables

**FIGURE
6-4**

dehydration agent along with the capital loan rate, construction loan rate and loan term are relatively insensitive with regard to effecting the percent DCFROR. To the contrary, a much more significant impact to the percent DCFROR results from changes in the total cost, general inflation rate, geofluid cost, feedstock cost, ethanol price, percent of debt financed, ethanol escalation rate, by-product value, and plant capacity factor. The overall sensitivity of a geothermal-ethanol plant percent DCFROR to cost variables is significantly higher than for the geothermal resource development case. For example, a 10 percent decrease in the cost of feedstock, the single largest production expense, results in an increase of roughly 12 percent in the DCFROR. Also of major importance to the geothermal-ethanol plant are the cost of the geofluid and the value of the process by-products.

The selling price of ethanol, in 1981 dollars, is also a highly sensitizing variable, however this cost should be well defined from the outset. What is not so well defined and of similar importance is the differential escalation rate between the price of ethanol and the general inflation rate. For the purpose of this analysis, an optimistic assumption was made that the cost of competitive petroleum products would continue to increase rapidly and that the demand for ethanol would increase such that the selling price of ethanol would rise at a rate of 3 percent above general inflation. All ethanol feedstocks and by-products were assumed to follow the ethanol escalation rate, while all other cost variables followed general inflation. The sensitivity of this assumption was also tested and the results appear in Figure 6-6, which shows the effect of feedstock cost, in dollars per liter (gallon) of ethanol produced, and differential escalation on the percent of DCFROR. Feedstock cost was selected as a variable in this case since it is one variable over which the geothermal-ethanol plant developer should have some control, going into the project, in the form of a long-term supply contract. The base case is indicated at 20 percent DCFROR, \$0.38 per liter (\$1.42 per gallon) of ethanol feedstock cost and a differential escalation rate of plus 3 percent. Projections of competitive petroleum product costs are not nearly as optimistic as the base case. Indications are that differential escalation rates in the range of zero to minus-two percent are much more likely over the next 10 year period. Therefore, one solution in order to satisfy the 20 percent minimum DCFROR criteria would be to look for a cheap mixture of feedstock supplies in the range of \$0.19 to \$0.27 per liter (\$0.71 to \$1.03 per gallon) of ethanol produced. Crop culls would be the most likely source of cheap feedstock and potato culls in particular would be the prime candidate for a cheap feedstock supply in the San Luis Valley, with the added benefit that potatoes are a net water producer in the ethanol production process.

Geothermal Ethanol Plant
Effect of Feedstock Cost and Differential Escalation on DCFROR

**FIGURE
6-6**

6.7 CONVENTIONAL FUEL ENERGY SAVINGS

The San Luis Valley ethanol plant replaces conventional fossil fuels in two ways. Geothermal energy is used in lieu of conventional oil or coal fired boilers to provide process heat during ethanol production. Additionally, the plant produces alcohol which can be blended with gasoline to produce a high quality motor fuel which effectively replaces an equivalent amount of gasoline at the refining level.

The replacement value of conventional fuels for the process heat requirements of an ethanol plant was estimated from Grain Motor Fuel Alcohol Technical and Economic Assessment Study, by Raphael Katzen Associates. Their technical analysis required 9.84×10^4 tons of coal for use as boiler fuel in producing 189M liters (50 million gallons) of ethanol annually. Based on heat of combustion for coal of 2.68×10^7 J/kg (11,500 Btu/lb), 2.38×10^5 Joules (2.26×10^{12} Btu) of fossil fuel energy could be replaced each year in the production of alcohol, or approximately 4.15×10^5 barrels of oil per year.

If the alcohol produced at the plant was sold to make gasohol (a 90:10 blend of gasoline and alcohol), crude oil refined to produce gasoline could be diverted for other uses. Therefore, if the ethanol replaced 50 million gallons of gasoline, an estimated 5.59×10^5 barrels of crude oil could be refined to other products or the import level could be reduced. The net savings in terms of fossil fuel energy is estimated to be 9.74×10^5 barrels of crude oil per year for a 50 million gallon annual production.

6.8 SUMMARY AND CONCLUSIONS

The economic evaluation presented in this section discusses the many financial incentives available for the development of a geothermal-ethanol plant and then utilizes those incentives in an economic analysis of the discounted cash flow rate of return of producing ethanol using geothermal energy in the San Luis Valley of Colorado.

The economic analysis utilizes basic economic criteria, listed in Table 6-1, to develop base case generic curves which are not site-specific and can be applied in evaluating many geothermal-ethanol plant development opportunities. A sensitivity analysis was conducted by individually varying each cost variable in the base case through a range of ± 50 percent.

The results of the economic evaluation show that the development of a geothermal-ethanol facility can only be profitable under very optimistic assumptions and that the results of the analysis are very sensitive to these assumptions. Some of these key assumptions include:

- 100 percent barley feedstock
- 3 percent differential escalation rate between ethanol prices and general inflation
- high by-product value.

The 100 percent barley feedstock was the only feedstock alternative considered that showed a discounted cash flow rate of return above the 20 percent minimum rate. A large ethanol plant utilizing a 100 percent barley feedstock in the San Luis Valley is highly unlikely based on the historical barley crop production along with the fact that 98 percent of the barley is grown exclusively on a contract basis for the Coors, Pabst and Schlitz breweries.

The 3 percent differential escalation rate between ethanol prices and general inflation was an optimistic assumption based on the cost of competitive petroleum products continuing to increase rapidly and, thereby, also the demand for ethanol. Projections of competitive petroleum product costs are not nearly as optimistic as the base case. Indications are that differential escalation rates in the range of 0 to minus-2 percent are much more likely over the next 10-year period. Under these conditions, none of the feedstocks considered in the analysis would provide the minimum discounted cash flow rate of return of 20 percent.

The analysis shows that the basic expenses of producing ethanol with geothermal energy exceed the market price of the ethanol itself. It is only the marketability of the process by-products that makes the base case geothermal-ethanol plant cost-effective. A reduction in the value of these by-products would result in a discounted cash flow rate of return of less than the minimum 20 percent required.

The optimism assumed in developing the economic base case cannot be justified in light of contradicting facts combined with the sensitivity of DCFROR to the assumptions. Therefore, one can conclude from this analysis that it is highly probable that a geothermal-ethanol facility developed in the San Luis Valley of Colorado would not provide the minimum rate of return required for such an investment.

SECTION 7

CONCEPTUAL DESIGN

7.1 INTRODUCTION

The ethanol system will follow a flow process typical of a conventional industrial scale ethanol plant. The design of the ethanol production plant is virtually independent of the geothermal system with the exception of the temperature limitations imposed by the geothermal reservoir. Conventional technology is used throughout the plant to eliminate any need for equipment development and to facilitate equipment purchase, plant construction and operation and maintenance. The conceptual design was developed by synthesizing in-house resources, information in the public domain, and discussions with enzyme manufacturers, ethanol producers and equipment vendors. This conceptual design identifies major equipment components which can be scaled for a facility to produce 76-189 million liters (20-50 million gallons) per year of 200 proof ethanol.

The facility is divided into 11 process diagrams corresponding to major processing sections in the ethanol plant. The plant is able to use potatoes and grains, dependent on the available supply and cost of each feedstock. The sections of the plant represented in schematic form are:

Section	100 - Cleaning and Initial Processing: Grains
Section	200 - Cleaning and Initial Processing: Potatoes
Section	300 - Cooking
Section	400 - Cooling and Saccharification
Section	500 - Fermentation
Section	600 - Distillation
Section	700 - Dehydration
Section	800 - By-Product Processing: Dried Grains
Section	900 - By-Product Processing: Thin Stillage
Section	1000 - Product and By-Product Storage
Section	1100 - Wastewater Treatment

7.2 HEAT BALANCE

In order to optimize the plant capacity, somewhere in the range of 76-189 million liters (20-50 million gallons) of annual production, an assessment of the total energy balance is required for the ethanol plant. Some assumptions were made in this evaluation to simplify the analysis while providing an initial estimate of capital costs and sizes of major equipment items. The conceptual design includes the heat balance for the four major process steps; cooking, fermentation, distillation and dehydration, as shown in Table 7-1. This heat balance is based on the Katzen Process heat balance, modified to reflect the fact that less heat is suitable for cascading due to the modification to low temperature operation.

The process heat required for the production of ethanol will be supplied by geothermal fluid or by recycling waste heat from one process step to another. Geothermal steam will be injected into the mash in the cooking process as indirect heating is inefficient and creates additional operation and maintenance problems because of the viscosity of the starch slurry. A steam ejector can be used to completely mix and heat a mash or starch slurry. During operation, the cold slurry is pumped from a holding vessel to the heater. Steam enters through the suction inlet and, during thorough mixing, the slurry absorbs the heat of the steam. The hot slurry is then discharged for further processing.

The heat capacity of the mash entering the fermenter was estimated at 0.79 kilocalorie/kg-°C (0.79 Btu/lbm°F) from a combination of the heat capacity of water and grains. If a measurement of the colloidal mixture can be tested in a lab, this constant should reflect the actual value for recalculation of heat balances. Actual specific heat value determines cooling water requirements and heat balance equations for the mash.

If an assumed cooking temperature of 140°C (284°F) is used, the ratio of steam to mash is 1:5. This quantity of steam at 140°C (284°F) releases the starch from the cell walls to form the primary mash which is subjected to saccharification and fermentation. This steam also dilutes the gelatinous slurry which greatly increases the ease of handling in subsequent process steps. The cooking process is done on a continuous basis which is regulated by the plant capacity and the available geothermal steam. The plant capacities stated in the report are based on the annual production of the plant assuming a 100 percent utilization factor. It is expected that the plant will require some shutdown time for preventive maintenance and also for unanticipated problems. Therefore, an estimated plant capacity factor of 75 percent was used in the economic analysis of the plant operations.

Table 7-1

HEAT REQUIRED FOR MAJOR PROCESS STEPS, kw (Btu/hr)*

Process	Plant Size, million liters/yr (million gallons/yr)			
	76 (20)	114 (30)	152 (40)	189 (50)
Cooking	9.8×10^3 (33.45×10^6)	14.7×10^3 (50.17×10^6)	19.8×10^3 (68.89×10^6)	24.5×10^3 (83.8×10^6)
Alcohol Distillation and Dehydration	15.4×10^3 (52.62×10^6)	23.1×10^3 (78.92×10^6)	30.8×10^3 (105.23×10^6)	38.5×10^3 (131.54×10^6)
Dy-Product Dehydration	11.5×10^3 (39.41×10^6)	17.3×10^3 (59.11×10^6)	23.1×10^3 (78.8×10^6)	28.9×10^3 (98.52×10^6)
TOTALS:	36.7×10^3 (125.48×10^6)	55.1×10^3 (188.20×10^6)	73.5×10^3 (250.92×10^6)	91.9×10^3 (313.66×10^6)

*Based on feedstock mix: wheat 40 percent, barley 30 percent, potatoes 30 percent.

7.3 INITIAL PROCESSING

The San Luis Valley Ethanol Plant will use pre-processing techniques common to conventional ethanol operations. Pre-processing of starchy or amylaceous materials includes removal of foreign matter, disposal of dirt or rocks and size reduction. Preliminary size reduction increases the surface area of the feedstock to the treatment media. Enzymatic attack is much more effective because there are more available sites for the enzyme to perform its catalytic action. Increased exposure will accelerate conversion time spans and increase yields. The ethanol plant will be capable of processing grains or potatoes as initial feedstocks. The major items of equipment that will be unique to a particular feedstock are in the initial processing phase.

7.3.1 Grains (Section 100)

The process flows and major equipment items for pre-processing grains are shown in Figure 7-1. The grain will be unloaded from trucks or trains and will be routed directly into the ethanol process or diverted to storage silos. The grain for ethanol conversion is conveyed to a vibratory separator that screens out rocks and large contaminants. The cleaned grain is delivered into a grain surge bin at the inlet to the hammermill which provides 3 hours of feed to the ethanol plant; 3000 bushels for a 76 million liter (20 million gallon) plant and 7500 bushels for a 189 million liter (50 million gallon) plant.

The screened grain is ground to reduce its size. A magnet on the inlet to the size reduction mill picks up tramp metal that may be in the feed stream. After the meal can pass through a 16 ASTM mesh screen it is sent to the cooking section where it is fed directly into the feed mix tank (Section 300). Water and condensate are added to make a starch slurry containing 30-35 percent solids. This mash is held at 60°C (140°F) for half an hour at a pH of 6.2 to 6.4 in the presence of alpha-amylase (Section 400).

The storage silos for the raw feedstock will be sufficient to assure continuous plant operation. Carbon dioxide generated during the fermentation process can be utilized in the storage silos to prevent premature spoilage by providing an inert atmosphere. For example, a plant sized for 76 million liters (20 million gallons) of annual production would require about 845 cubic meters (24,000 bushels) of wheat per 24-hour period. At least a 10-day supply should be on hand, therefore the storage silos for a 76 million liter plant will be sized for approximately 8450 cubic meters (240,000 bushels) and a 189 million liter plant (50 million gallons) will require storage capacity of 21,125 cubic meters (600,000 bushels).

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Receiving, Storage and Pre-processing Grains San Luis Valley Geothermal Alcohol Plant Section 100

FIGURE
7-1

7.3.2 Potatoes (Section 200)

The initial processing technique for potatoes, as shown in Figure 7-2, differs dramatically from the dry initial processing for wheat or barley. Water addition is not required for mash formation with potatoes as a feedstock because potatoes inherently contain over 75 percent water, as shown in Table 7-2 (Stenzel et al., 1980).

Table 7-2

CLEAN POTATO COMPOSITION

Water	77.5%
Starch	15.0%
Proteins and Fats	2.1%
Fiber	5.4%
	<hr/>
	100.0%

Potatoes are unloaded into a potato cellar which provides a 10 day storage capacity for the plant. A front-end loader delivers the potatoes from the potato cellar to a conveyor belt which transports the potatoes to an 8-hour storage location. The potatoes are conveyed via a flume to potato washers which remove field dirt and other contaminants. Flume water is recycled. Wash water is sent to ponds where the solids settle out. Clarified water from the pond is recycled to the wash cycle.

After initial cleaning, the potatoes are sent into mechanical disintegrators which crush the whole potatoes. The mash is screened to remove oversize pieces which are recycled to the disintegrators. The potato mash then flows into a centrifuge where it is separated into a fraction that contains approximately 32 percent solids by weight which is used as the mash slurry for conversion to ethanol. The remaining fraction, essentially water that was contained in the potatoes, is sent to wastewater treatment. The "dewatered" slurry is sent to the cooking section where warm condensate from the flash coolers is added to condition the mash.

A net water gain is realized from an ethanol plant using potatoes as a feedstock. The effluent from the plant will be directed to a water treatment plant and used for washing the potatoes in the initial processing cycle and diluting the mash prior to saccharification. Solids from the water treatment plant will be disposed of in an appropriate waste disposal site.

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7.4 COOKING (SECTION 300)

The process flow and major equipments of the cooking section of the system are shown in Figure 7-3. (This section processes the mash in accordance with a Miles Laboratory recommended procedure.) Following cleaning and size reduction, grain and/or potato mash are put into an agitated tank and mixed with warm water as necessary to produce a warm (60°C) starch slurry containing 30-35 percent solids. Sodium hydroxide is added to adjust pH between 6.0 and 6.4 and the calcium level is adjusted to no less than 50 ppm calcium ion. Finally the enzyme alpha-amylase is added to hydrolyze the α -D-1.4 glucosidic linkages of the starch. The tank is sized to retain the slurry for 1/2 hour to ensure proper wetting.

7.4.1 Liquefaction

Following wetting and adjustment, the mash is precooked by passing it through a jet cooker and heated to 85°C (185°F). Precooking raises the viscosity significantly. Alpha-amylase demonstrates maximum hydrolysis in the presence of mash with 10-30 percent Dry Starch Basis (DSB) at 85°C (185°F) in a pH range of 5.5 to 7.0. Between 7.7 and 15.4kg/hr of alpha-amylase are required for a 76 million liter plant.

The mash is collected in a series of three agitated tanks. The tanks are designed to provide 1 hour total retention time. During this liquefaction phase, alpha-amylase reduces the viscosity of the mash from approximately 7500-10,000 cps in the first tank to 2000-3000 cps in the second and third tanks.

7.4.2 Saccharification (Section 400)

The process flow and major components of the saccharification section are shown in Figure 7-4.

The ejector type cookers used in ethanol plants require 5.86-6.90 bars (85-100 psia) steam. Modifications could be made to the ejector to accommodate 5.2 bars (75 psia) steam, but steam pressures lower than 5.2 bars (75 psia) could not be effectively used in the ejector-cooker.

Because the geothermal resource is not expected to be hot enough to produce sufficient steam at 5.2 bars, 153°C (75 psia, 307°F), alternatives to the ejector type cooker were evaluated. Two options were investigated: the use of a small package boiler that would provide the required steam pressure or the use of a thermocompressor which would boost the pressure and temperature of the geothermal steam to the required levels. The thermocompressor is considered the better solution, therefore the San Luis Valley plant has been designed to use a thermocompressor to boost the

Cooking San Luis Valley Geothermal Alcohol Plant Section 300

**FIGURE
7-3**

Cooling and Saccharification San Luis Valley Geothermal Alcohol Plant Section 400

**FIGURE
7-4**

temperature and pressure of the 140°C steam from the flash separator tanks to 164°C and 6.9 b (327°F, 100 psia). This steam is used in a second steam jet cooker to boost the temperature of the mash to 140°C. After passing through the cooker, the mash enters cooking coils that are sized to provide the required retention time of 15 minutes at the plant throughput. These coils allow for a continuous cooking process which minimizes the chance of the solids settling out in the cooking phase.

The mash is flash cooled to 100°C (212°F) at atmospheric pressure, and to 85°C (185°F) in a vacuum flash chamber. The 85°C (185°F) mash is then passed through a series of three tanks where secondary liquefaction occurs. The mash is maintained at a pH between 6.0 and 6.4 and held in the reactor tanks for at least 1 hour. At this point the viscosity of the mash will be less than 700 cps.

After secondary liquefaction, the mash passes through a second vacuum flash tank which reduces the temperature of the mash to 60°C (140°F) at an approximate pressure of 0.2 bars (2.9 psia). This vacuum can be created by either an ejector that uses geothermal steam, or a vacuum compressor. The released steam from all of the flash cooling phases are used in the pre-cooking section to condition the mash.

The pH of the slurry is adjusted to 4.2 to 4.5 with dilute HCl and the enzyme glucoamylase is added to break the starch into fermentable glucose. Glucoamylase hydrolyzes both the α -D-1,6 glycosidic branch points and the predominating α -D-1,4 glucosidic linkages of starch. Glucoamylase has an optimum pH range of 3.8 to 4.5 at 60°C (140°F) with excellent saccharification exhibited from 30°C to 60°C (86°F to 140°F). Temperatures above 60°C (140°F) result in loss of enzyme activity. The mash is then transferred to an agitated saccharification tank where it is held for 2 hours at 60°C.

The guidelines for the cooking and saccharification processes are detailed below dependent on what temperature steam is delivered to the cooking vessels.

- A.
 1. Presoak for 1/2 hour at 60°C (140°F)
 2. Pass through jet cooker, heat to 85°C (185°F)
 3. Hold for 1 hour at 85°C (140°F)
 4. Pass through jet cooker, heat to 140°C (284°F)
 5. Hold in cooker for 15 minutes
 6. Ferment for 60 hours

Yield: 94-96%

- B.
1. Presoak for 1 hour at 60°C (140°F)
 2. Pass through jet cooker, heat to 85°C (185°F)
 3. Hold for 1 hour at 85°C (185°F)
 4. Pass through jet cooker, heat to 150°C (302°F)
 5. Hold in cooker for 5 minutes at 150°C (302°F)
 6. Ferment for 48 hours

Yield: 94-96%

Increased retention time in the cookers and fermentors increases equipment size or number. Additional fermentation tanks will be necessary for the lower temperature (140°C).

At the lower temperature (140°C), more steam can be produced from a saturated liquid at a specific reservoir temperature. Since flashing to steam will require high mass flow rates of geothermal fluid, the lower temperature process (A) and associated longer retention time will be the basis for the process plant design resulting in higher initial capital costs. Once the resource confirmation plan for the geothermal reservoir in the San Luis Valley is followed, in Section 3, these specifications can be adjusted to reflect the additional data collected in the evaluation program. If resource temperatures are higher than anticipated, the plant equipment should be scaled down to meet the requirements of the higher temperature steam process (B).

7.5 FERMENTATION (SECTION 500)

The process flow and major components of the fermentation section are shown in Figure 7-5. The mash must be cooled to allow the fermentation of alcohol (see Figure 7-4). After saccharification, the latter stages of cooling are accomplished by the circulation of cooling water in a heat exchanger to further cool the mash temperature to 30°C (86°F). The mash is adjusted to 25 percent solids with the addition of thin stillage, and yeast is added to convert the glucose into ethanol. Ideally, the temperature of the fermenting mash should not exceed 33°C (91°F) to prevent killing the yeast cells.

Although fermentation is an exothermic process, cooling is only required during certain portions of the fermentation cycle. The greatest demand for cooling will be in the initial phase of fermentation because of the relatively high inlet temperature of the mash. Also, the high sugar content of the mash as it enters the fermentation vats assures a plentiful supply of nutrients for the yeast, a high rate of conversion from glucose to ethanol and thus a high rate of heat evolving from the process. The heat

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Fermentation San Luis Valley Geothermal Alcohol Plant Section 500

FIGURE
7-5

evolved from the fermentation reaction is approximately 185 k-cal/liter (2772 Btu/gallon) of anhydrous ethanol produced (Stenzel et al., 1980). During the winter months, heat loss to the atmosphere may require heating for the fermentation tanks to maintain the fermentation temperature. Heat loss can be reduced by placing the fermentation tanks in a building.

At the end of the 48 to 60-hour fermentation cycle, the vat is emptied into the beer well which is the feed for the distillation columns. This beer well acts as a surge tank to allow for continuous distillation. After each fermentation vat is emptied, it is cleaned and readied for another batch of saccharified mash. The cycle for each fermentation tank is dependent on the expected product flow rate. For a 76 million liter plant (20 million gallon) it takes approximately 10 hours to fill a 250,000 gallon tank to 85 percent of its rated capacity, for a 189 million liter plant it requires only 4 hours to fill each tank. Each plant design assumes a 60 hour fermentation period, a 4 hour time interval to drain one tank into the beer well and 4 hours to clean the tank. Based on these parameters eight 250,000 gallon tanks are required for a 76 million liter (20 million gallons) plant and eighteen 250,000 gallon tanks are required for a 189 million liter (50 million gallon) plant. For the purposes of this study, the yeast solids produced in the fermentation cycle become a part of the by-product Distiller Dry Grains.

7.6 DISTILLATION (SECTION 600)

The process flow and major components of the distillation section are shown in Figure 7-6. One of the major engineering problems for conceptual design formation is the limited data available on the operating conditions of the dehydration and distillation columns. Information on the energy requirements and techniques for recycling waste heat is generally proprietary and is not released by equipment vendors. A more detailed energy balance of this section of the ethanol plant would be possible only if an agreement for non-disclosure of proprietary information could be reached. Based on our expected steam temperature and pressure, mass flow rates of steam were specified for the combined distillation/dehydration process steps.

Distillation begins as the beer from the fermentation beer well flows into the distillation column. Geothermal steam is introduced into reboilers which provide the process heat for the concentration of alcohol. Two techniques are forwarded to reduce steam requirements in distillation columns; one should be incorporated into the design and one put in practice for plant operation. An increased number of trays will reduce

Distillation San Luis Valley Geothermal Alcohol Plant Section 600

**FIGURE
7-6**

the required reflux rate and as a result reduce steam usage (Thumann, 1977). Also, distillation columns should be operated near flooding conditions. At reduced rates, separation efficiency decreases. To correct this condition, the normal top operating pressure should be reduced.

The beer is introduced into the middle sections of the distillation column. As the beer passes down the column, it loses its lighter boiling constituents and the concentrated ethanol/water overhead passes on to the aldehyde or heads column and then to the dehydration tower. The heads column separates the low-boiling impurities from the process stream as a bottom product. The purified ethanol/water liquid proceeds to the dehydration tower where the remaining water is removed. The bottom discharge from the distillation column or stillage contains proteins, residual sugars, yeast and water and can be used as an animal feed.

7.7 ALCOHOL DEHYDRATION (SECTION 700)

The process flow and major components of the dehydration section are shown in Figure 7-7. The dehydration process chosen for the San Luis Valley conceptual design utilizes the azeotropic distillation technique with benzene as the dehydration agent. Although benzene requires more energy and has been associated with cancer if personnel are subjected to repeated extended exposure, most commercial plants continue to use it because they are working with a substance with known risks and they are able to minimize potentially hazardous communication. The other dehydration agents have not been used extensively, and dangers associated with their use are unknown. However, experimental data indicates cyclohexane or pentane may be more efficient and they should be investigated as possible entrainers. An extractive distillation technique that uses gasoline is currently under patent application and may prove to be the ideal dehydration/denaturant agent for the production of gasohol.

With benzene as the entrainer, the water is removed from the 95 percent alcohol by the formation of a ternary azeotrope of alcohol, water and benzene which boils at a lower temperature (64.85°C) than the 95 percent alcohol. Anhydrous ethanol is obtained from the bottom of the tower as the water is removed in the ternary mixture.

The overhead mixture with the component percentages ethanol 18.5 percent, benzene 74.1 percent, and water 7.4 percent is condensed and passed to a decanter in which two liquid layers form. The upper layer, rich in benzene, returns to the dehydration tower and the lower layer is fed to a hydrocarbon stripper which produces the

Dehydration San Luis Valley Geothermal Alcohol Plant Section 700

**FIGURE
7-7**

ternary azeotrope as the overhead and benzene free aqueous alcohol as a bottoms product. This aqueous alcohol is fed to a final distillation column which produces 96 percent alcohol as an overhead which is returned as feed to the distillation tower and a bottom product which is virtually pure water (Shreve and Brink, 1977).

Benzene losses are estimated at less than 0.5 percent by volume of the anhydrous ethanol produced. The hydrocarbon stripper effectively removes the benzene from the water in the dehydration process and is recycled to the dehydration tower for formation of the ternary azeotrope.

7.8 BY-PRODUCT PROCESSING: DRIED GRAINS (SECTION 800)

The process flow and major components of the dried grains by-product processing section are shown in Figure 7-8. The bottoms of the beer or distillation column, or stillage, contain residual solids which have a high nutritive value for livestock feed. This whole stillage can be fed directly to cattle if a nearby market exists; for example, a feedlot, or it can be dewatered and shipped to appropriate locations. The stillage is dewatered to extend the storage life of the product and to reduce shipping costs.

After exiting from the distillation column, the bottoms are centrifuged to produce two fractions. The thin stillage or overflow which is between 6 and 7 percent solids is processed in the vapor compression evaporators to generate fresh water which is recycled to the cookers. The other fraction, approximately 38 percent solids and 25 percent of the whole stillage flow, is further dewatered by mechanical presses or is dried by the addition of heat. Dehydration is accomplished after mixing the concentrated syrup from the thin stillage processing step with the thick stillage cake which evaporates the water from the wet grains. For extended storage, the moisture content of the grains must be reduced to 10 percent to prevent spoilage.

Large quantities of stillage will be generated at any plant producing ethanol in the 76-189 million liters (20-50 million gallon) range, so dehydration is required for either extended storage or product export. For the San Luis Valley Ethanol Plant, geothermal fluid was selected as the best source of energy for grains dehydration. High temperature rotary grain dryers normally use the exhaust from natural gas burners to evaporate moisture from agricultural products. As a geothermal alternative, this plant will draw air in over coils containing geothermal steam. This heat exchanger will use forced air circulation in order to eliminate this natural gas requirement.

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By-Product Processing Dried Grains San Luis Valley Geothermal Alcohol Plant Section 800

**FIGURE
7-8**

7.9 BY-PRODUCT PROCESSING: THIN STILLAGE (SECTION 900)

Process flows and the major components of the thin stillage processing section are shown in Figure 7-9, which is approximately 75 percent of the whole stillage flow. Thin stillage separated in the centrifuges of initial by-product processing step (Section 800) is preheated and sent to a vapor compression evaporation unit where it is separated into a thick syrup and water. Vapor compression evaporation substitutes the mechanical work of a steam compressor for the heating steam required in traditional single or multiple effect evaporators. The principle benefit derived from vapor compression is significantly lower energy consumption and operation costs (Aquachem, 1981). An additional benefit which affects the San Luis Valley Ethanol Plant include elimination of cooling water requirements.

The thin stillage is pumped through the heat exchanger where it is preheated by the outgoing distillate and concentrate. The feed liquor then enters the recirculation header where it mixes with some of the concentrated liquor, and is sprayed over the evaporator tube bundle where some of the water in the feed is converted to vapor. The liquor which does not evaporate is collected in the evaporator sump and recirculated. A portion of this concentrated stream is discharged as a product after preheating the feed stream.

The vapor that is generated passes through entrainment separators, where liquid droplets are removed, to the compressor. In the compressor the temperature and pressure of the vapor is increased. The vapor is then discharged into the evaporator tube bundle where it provides the process heat for concentration of the feed liquor. The vapor condenses and is pumped through the heat exchanger to preheat the inlet stream. The distillate is either sent for water treatment in Section 1100 or is used directly in the feed mixing process step.

This vapor compression evaporation will be combined with a single-effect evaporator. The thin stillage will be concentrated from 6.5 percent total solids to approximately 40 percent solids in the compression evaporator and the additional concentration to 55 percent solids will be performed in the forced circulation evaporator finish concentrator. Both evaporators are driven by a single motor driven centrifugal compressor (Aquachem, 1981).

The concentrated syrup generated by the vapor compression unit will be mixed with the thick stillage prior to final drying to Distiller Dried Grains. The condensate is collected in a tank and either returned to the initial treatment section or to the water processing system as dictated by operating conditions. The thick stillage and

By-Product Processing Thin Stillage Evaporation San Luis Valley Geothermal Alcohol Plant Section 900

**FIGURE
7-9**

concentrated syrup are mixed in a turbulizer as shown in Figure 7-8 and then dried in a turbo-dryer to a 10 percent moisture content. This dewatered by-product of the ethanol process can be sold as an animal feed supplement.

7.10 PRODUCT AND BY-PRODUCT STORAGE (SECTION 1000)

Process flows and major components of the product and by-product storage section are shown in Figure 7-10. The storage area provides tanks for storage of the ethanol, fusel oils and aldehydes as well as bins for storage of the DDG.

Alcohol received from the dehydration section is initially placed in day tanks which are sized to hold 4 hours production each. The day tanks provide for testing prior to transfer to bulk storage. Acceptable batches from the day tanks are sent to the main storage tanks which are sized to hold about 30 days product. For a 76 million liter (20 million gallon) facility, these tanks would provide about 6,700,000 liters (1,800,000 gallons) storage capacity. Unacceptable batches from the day tanks are sent back to the Distillation Section of the plant for redistilling.

Fusel oil and aldehydes from the dehydration section are retained in storage tanks for transfer. They can be either sold directly or mixed with the ethanol as is sometimes done when the ethanol is to be used in gasahol. In addition to the ethanol, fusel oil, and aldehyde tanks, the storage area contains a denaturant tank for storage of the denaturant which is mixed with the ethanol when it is being sold for non-consumptive uses.

Dry grains are stored in this area in large bins having about a 2-week production capacity. This would approximate 6610 cubic meters (235,000 cubic feet) for a 76 million liter (20 million gallon) plant.

The product and by-products can be transferred by either truck or rail.

7.11 WASTEWATER TREATMENT (SECTION 1100)

The process flow and major components of the wastewater treatment section are shown in Figure 7-11. The alcohol production process as conceptually designed results in several recoverable wastewater streams from the plant. These various wastewater streams can be divided into two categories: clean condensates requiring little or no treatment, and contaminated wastewaters requiring substantial treatment before reuse or release outside the plant.

The first category is made up primarily of waters recovered from the hydrocarbon stripping column bottoms and the flash cooling tanks. These waters can be

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Product and By-Product Storage San Luis Valley Geothermal Alcohol Plant Section 1000

**FIGURE
7-10**

Wastewater Treatment Facilities San Luis Valley Geothermal Alcohol Plant Section 1100

**FIGURE
7-11**

recycled within the plant as they contain small amounts of carryover ethanol as their only significant contaminant.

Category two consists primarily of wastewaters recovered from centrifuges utilized for feedstock preparation (potato feedstock) and by-product recovery. The facility wastewater treatment plant will also receive flows from silt pond blowdown (potato feedstock), fermenter cleaning, and general plant wash down.

These flows contain several contaminants that require treatment before the water is suitable for reuse or release. These contaminants include; a high biochemical oxygen demand (BOD) due to the presence of large quantities of organic matter, high concentrations of suspended and dissolved solids, a somewhat low pH (acidic), and toxicants (primarily those used to sterilize the fermenters).

Conventional, on-site primary and secondary treatment of these wastes will render them acceptable for reuse within the plant or release outside the plant. This conventional treatment will consist of primary settling to reduce the suspended solids, dissolved air flotation to further remove suspended matter, pH correction, and activated sludge treatment to treat the organic pollutants. Biological solids remaining after activated sludge treatment will be removed in a gravity clarifier. A sulfonation unit will also be required to treat the chemicals used in sterilizing the fermenters.

7.12 COST ESTIMATE

Capital cost estimates for geothermal-ethanol plants in the range of 76-189 million liters (20-50 million gallons) per year are shown in Table 7-3. This table provides a breakdown of the estimated cost for each section of the process discussed in this chapter, plus the utilities, land and service buildings and geothermal exploration and system costs for 76, 114, 152, and 189 million liter (20, 30, 40 and 50 million gallon) production facilities. All cost estimates are in 1981 dollars. The estimated cost of the geothermal system is based on a resource temperature of 155°C (311°F) and a flow rate of 1700 l/min (450 gpm). Since the cost of a geothermal system can vary significantly depending on the temperature of the resource and the realizable flow rates of the wells, this estimate is considered an average or mid-range cost estimate.

The estimates of Table 7-3 include the cost of material; onsite construction materials used in system assembly; labor costs; indirect costs such as engineering costs, shipping fees, contractor fees, etc.; and buildings and structures associated with the various systems.

Table 7-3

**TYPICAL CAPITAL COST ESTIMATES FOR GEOTHERMAL-ETHANOL PLANTS
IN THE RANGE OF 76-189M LITERS (20-50MM gallons) PER YEAR**

Section	Systems(s)	Annual Plant Capacity			
		76M liters (20MM gal)	114M liters (30MM gal)	152M liters (40MM gal)	189M liters (50MM gal)
100	Grain receiving, storage and processing	\$ 897,000	\$ 1,101,000	\$ 1,304,000	\$ 1,511,000
200	Potato receiving, storage and preprocessing	\$ 4,646,000	\$ 6,799,000	\$ 8,950,000	\$ 11,102,000
300	Cooking	\$ 1,701,000	\$ 2,307,000	\$ 2,917,000	\$ 3,525,000
400	Saccharification	\$ 567,000	\$ 770,000	\$ 973,000	\$ 1,175,000
500	Fermentation	\$ 2,274,000	\$ 3,103,000	\$ 3,927,000	\$ 4,754,000
600	Distillation	\$ 3,470,000	\$ 4,917,000	\$ 6,360,000	\$ 7,807,000
700	Dehydration	\$ 3,470,000	\$ 4,917,000	\$ 6,360,000	\$ 7,807,000
800	DDG processing	\$ 4,012,000	\$ 5,926,000	\$ 7,849,000	\$ 9,756,000
900	Thin Stillage processing	\$ 9,822,000	\$ 14,510,000	\$ 19,196,000	\$ 23,884,000
1000	Product and By-product storage	\$ 1,877,000	\$ 2,472,000	\$ 3,069,000	\$ 3,663,000
1100	Wastewater treatment	\$ 2,073,000	\$ 2,868,000	\$ 3,482,000	\$ 4,010,000
	Utilities	\$ 3,632,000	\$ 4,375,000	\$ 5,117,000	\$ 5,860,000
	Land and Buildings	\$ 1,425,000	\$ 1,526,000	\$ 1,625,000	\$ 1,726,000
	Ethanol Plant	\$39,866,000	\$ 55,591,000	\$ 71,120,000	\$ 86,580,000
	Resource Exploration	\$ 4,398,000	\$ 6,598,000	\$ 8,797,000	\$ 10,996,000
	Geothermal System	\$32,341,000	\$ 48,511,000	\$ 64,682,000	\$ 80,852,000
	TOTAL COST	\$76,605,000	\$110,700,000	\$144,599,000	\$178,428,000

Utilities are considered to include the make-up water system, cooling water system, fire fighting system, instrument and control system, interior lighting and electrical distribution, and area piping and sanitary system. Land and building costs includes land acquisition for water rights and plant siting along with site preparation costs; roads, parking and outside lighting; railroad sidings; and operations and maintenance buildings. Appendix D contains the estimates for the major equipment which are included in the estimate in Table 7-3.

Some costs for the ethanol plant show an economy of scale for increased plant size. This is shown in Figures 7-12 through 7-15 for utilities, equipment and facilities costs. The major utilities costs for the plant generate a high first cost, such as electrical transmission lines or sewer costs but the incremental cost for additional capacity is relatively small. These costs which decrease when apportioned over the production capacity are balanced against items which have an increased unit price as the size of the commercial plant becomes larger, for instance feedstock costs. As long as the plant can be supplied by local agricultural markets, feedstocks will be a fairly stable cost item in plant production. However, it is very likely that the plant's requirements will exceed local supplies, and therefore feedstock will have to be imported from other areas with a resultant additional transportation expense. Cost estimates for feedstocks used in Section 6, Economic Evaluation, of this report include transportation costs.

San Luis Valley, Colorado - Process Equipment Cost vs Annual Capacity

**FIGURE
7-12**

WESTEC Services, Inc.

San Luis Valley, Colorado - Process Equipment Cost vs Annual Capacity

**FIGURE
7-13**

San Luis Valley, Colorado - Utility Cost vs Annual Capacity

**FIGURE
7-14**

Facilities Cost vs Annual Capacity

**FIGURE
7-15**

SECTION 8
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APPENDIX A

AMBIENT AIR QUALITY STANDARDS FOR THE STATE OF COLORADO

Adopted: September 10, 1970
Effective: December 17, 1970
Amended: September 4, 1975
Effective: December 18, 1975
Repealed and Reenacted: August 11, 1977
Effective: October 27, 1977

SULFUR DIOXIDE (SO₂) AMBIENT AIR STANDARDS FOR THE STATE OF COLORADO

- A. The actual concentration of sulfur dioxide at any given receptor site (no greater than five meters above ground level) in the State of Colorado shall not exceed a three-hour maximum of 700 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$) more than once in any twelve-month period.
- B. The following ambient standards for sulfur dioxide are expressed as allowable amounts of increase in ambient concentration (increments) over an established baseline. All concentrations are expressed in micrograms per actual cubic meter under local conditions of temperature and pressure.

	<u>Category I</u> (incremental)	<u>Category II</u> (incremental)	<u>Category III</u> (incremental)
Annual arithmetic mean	2	10	15
24-hour maximum	5	50	100
3-hour maximum	25	300	700

1. The above 24-hour and 3-hour standards are not to be exceeded at any given receptor site more than once in any twelve-month period.
2. The "baseline" for these incremental standards is defined as that concentration of sulfur dioxide either measured or estimated by the Division to exist on the effective date of this amended regulation.

- C. The method used to measure sulfur dioxide is the manual West-Gaeke sulfamic acid (24-hour bubbler) method. Other methods may be used if they have been demonstrated to the Division to be equally or more specific, sensitive, and reproducible. Results are expressed as micrograms of sulfur dioxide per actual cubic meter of ambient air. These values may be converted to parts per million by volume by dividing by 2860 ($1 \text{ ppm} = 2860 \text{ } \mu\text{g}/\text{m}^3$ at 0°C and 760 mmHg (Torr)).

AMBIENT AIR QUALITY STANDARDS FOR THE STATE OF COLORADO*

<u>Pollutant</u>	<u>Averaging Time</u>	<u>Ambient Air^{1,2,3} Quality Standards</u>	<u>Methods⁴</u>
OXIDANT (Ozone)	1-hour	160 $\mu\text{g}/\text{m}^3$	Ethylene Chemiluminescent
CARBON MONOXIDE (CO)	8-hour	10 $\mu\text{g}/\text{m}^3$	Non-Dispersive Infrared Spectroscopy
CARBON MONOXIDE (CO)	1-hour	40 $\mu\text{g}/\text{m}^3$	Non-Dispersive Infrared Spectroscopy
NITROGEN DIOXIDE (NO_2)	Annual Average	100 $\mu\text{g}/\text{m}^3$	Chemiluminescent

ALL MEASUREMENTS OF AIR QUALITY ARE CORRECTED TO A REFERENCE TEMPERATURE OF 25C AND TO A REFERENCE PRESSURE OF 760 MILLIMETERS OF MERCURY (1,013.2 MILLIBARS)

*Adopted: April 27, 1978

¹ Federal Primary Standards - The levels of air quality necessary, with adequate margin of safety, to protect the public health, attainment of each National Ambient Air Quality Standard by no later than December 31, 1982. Five-year extension for CO and O_3 possible, plan must be submitted by July 1, 1982.

² The Federal Secondary Standards of Oxidant, CO and NO_2 are the same as the primary standards and are the same as the proposed Colorado Ambient Standards listed above.

³Standards other than annual averages are not to be exceeded more than once per year.

⁴Reference method as described by E.P.A. An equivalent method may be used if it has consistent relationship to reference method and is approved by E.P.A. and the Air Pollution Control Division.

APPENDIX B

CONVERSION TABLES

Volume

$1 \text{ bu} = 1.244 \text{ ft}^3$
 $1 \text{ bu} = 0.0352 \text{ m}^3$
 $1 \text{ ft}^3 = 0.0283 \text{ m}^3$
 $1 \text{ acre-ft} = 43,560 \text{ ft}^3$
 $1 \text{ km}^3 = 1 \times 10^9 \text{ m}^3$
 $1 \text{ acre-ft} = 1233.5 \text{ m}^3$
 $1 \text{ m}^3 = 1000 \text{ liters}$
 $1 \text{ gallon} = 3.785 \text{ liters}$

Energy

$1 \text{ Btu} = 1055 \text{ Joules}$
 $1 \text{ Joule} = 0.239 \text{ calories}$
 $1 \text{ Btu} = 0.253 \text{ kcal}$
 $1 \text{ Btu} = 3.929 \times 10^{-4} \text{ hp-hr}$
 $1 \text{ Btu} = 777.9 \text{ ft-lb}_f$
 $1 \text{ Btu} = 2.930 \times 10^{-4} \text{ kw-hr}$

Mass

$1 \text{ kg} = 2.205 \text{ lb}_m$

Weight

$1 \text{ cwt} = 100 \text{ lb}_f$
 $1 \text{ cwt} = 0.04563 \text{ metric tons}$
 $1 \text{ short ton} = .903 \text{ metric tons}$

Length

$1 \text{ m} = 3.281 \text{ ft}$
 $1 \text{ m} = 39.37 \text{ in}$
 $1 \text{ m} = 6.214 \times 10^{-4} \text{ miles}$

Area

$1 \text{ acre} = 43,560 \text{ ft}^2$
 $1 \text{ m}^2 = 10.76 \text{ ft}^2$
 $1 \text{ acre} = 4.047 \times 10^3 \text{ m}^2$
 $1 \text{ hectare} = 2.47 \text{ acres}$

Miscellaneous

$1 \text{ gallon/cwt} = .0834 \text{ liter/kg}$
 $1 \text{ gallon/bu} = 107.53 \text{ liter/m}^3$
 $1 \text{ lb/bu} = 12.9 \text{ kg/m}^3$
 $1 \text{ \$/cwt} = 0.022 \text{ \$/kg}$

Pressure

$1 \text{ pound per in}^2 = 0.0703 \text{ kg/cm}^2$
 $1 \text{ pound per in}^2 = 6.805 \times 10^{-2} \text{ atm}$
 $1 \text{ pound per in}^2 = 6.895 \times 10^4 \text{ dyne/cm}^2$
 $14.5 \text{ pounds per in}^2 = 1 \text{ bar}$

Temperature

$T_f = 32^\circ\text{F} + T_c(9/5)$

APPENDIX C

HAZARDOUS COMPOUNDS: SAFETY MEASURES

HYDROCHLORIC ACID (HCL)

Description: Reagent grade acid 37% HCL, clear solution, commercial grade, slightly yellow.

Fire and Explosion Hazard: Not flammable.

Life Hazard: The gas has a suffocating effect when breathed and is poisonous.

SODIUM HYDROXIDE (NaOH)

Description: White flakes or pellets. Colorless liquid as 50% solution.

Fire and Explosion Hazard: Noncombustible, but reactive. When diluted, solution gets hot.

Life Hazard: Causes skin burns.

ETHYL ALCOHOL (CH₃CH₂OH)

Description: Clear, colorless liquid with burning taste

Fire and Explosion Hazard: Flammable liquid. Vapors form flammable mixtures with air.

Flash Point 12.8°C

Flammable Limits 3.28-18.95%

Ignition Temperature 363°C

Vapor Density (air = 1) 1.6

Specific Gravity 0.8 (water soluble)

Boiling Point 178.4°C

Odor Detectable at 5-10 ppm

Flash point of 5% alcohol/water solution 62°C (144°F)

Flash point of 10% alcohol/water solution 49°C (120°F)

Flash point of 15% alcohol/water solution 43°C (110°F)

Flash point of 20% alcohol/water solution 36°C (97°F)

Life Hazard: Exposure to concentration above 1000 ppm may cause headache, and irritation of the eyes, nose and throat. If continued for prolonged time, will cause drowsiness and stupor. Contact with liquid can cause defatting of skin.

CARBON DIOXIDE (CO₂)

Description: A colorless, odorless and tasteless gas that is heavier than air.

Fire and Explosion Hazard: None. Is a fire extinguishing agent.

Life Hazard: Carbon dioxide is an asphyxiant. Symptoms include dizziness, headache, shortness of breath, muscular weakness and drowsiness. OSHA standards require oxygen concentration of 19.5% or greater before entry is made to tanks or vessels. Skin contact with CO₂ snow will cause frost burns.

BENZENE (C₆H₆)

Description: Colorless, flammable liquid.

Fire and Explosion Hazard: Flammable liquid vapors form flammable mixture with air.

Flammable Limits 1.4-7.1%

Specific Gravity 0.878

Boiling Point 80.1°C

Life Hazard: Benzene is a proven human carcinogen capable of causing the cancer of leukemia. It produces an anesthetic-like effect inducing drowsiness and eventual coma if inhaled in high concentrations (1000 part per million (ppm) range). In 1978 the Occupational Safety and Health Administration (OSHA) proposed an emergency temporary standard of 1 ppm for the Threshold Limit Value - Time Weighted Average (TLV-TWA). This is the value allowed for a normal 8-hour workday or 40-hour workweek, to which nearly all workers may be repeatedly exposed, day after day, without adverse effect. A continuing legal battle has caused this standard not to be implemented. The current TLV-TWA is 10 ppm, with a Short Term Exposure Limit (STEL) of 50 ppm for a period up to 15 minutes.

APPENDIX D
MAJOR EQUIPMENT COST ESTIMATES

Table D-1A

SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 100
RECEIVING, STORING AND PREPROCESSING OF GRAINS
(Metric Units)

SECTION 100, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Truck Unloading Bin		35.20 m ³ /hr	\$ 35,000	35.20 m ³ /hr	\$ 35,000	35.20 m ³ /hr	\$ 35,000	35.20 m ³ /hr	\$ 35,000
2. Truck Unloading Bin Screw Conveyor		105.60 m ³ /hr	\$ 8,000	158.40 m ³ /hr	\$ 9,500	211.20 m ³ /hr	\$ 11,000	264.00 m ³ /hr	\$ 12,600
3. Rail Unloading Bin		91.52 m ³	\$ 45,000	91.52 m ³	\$ 45,000	91.52 m ³	\$ 45,000	91.52 m ³	\$ 45,000
4. Rail Unloading Bin Screw Connector		105.60 m ³ /hr	\$ 8,500	158.40 m ³ /hr	\$ 10,150	211.20 m ³ /hr	\$ 11,800	264.00 m ³ /hr	\$ 13,500
5. Screw Connectors to Bucket Elevator		105.60 m ³ /hr	\$ 11,000	158.40 m ³ /hr	\$ 13,600	211.20 m ³ /hr	\$ 16,200	264.00 m ³ /hr	\$ 18,700
6. Bucket Elevator		105.60 m ³ /hr	\$ 27,000	158.40 m ³ /hr	\$ 33,800	211.20 m ³ /hr	\$ 41,000	264.00 m ³ /hr	\$ 48,000
7. Diverter Valve			\$ 1,800		\$ 1,800		\$ 1,800		\$ 1,800
8. Storage Silos (10 days)		8,448.00 m ³	\$116,000	12,672.00 m ³	\$174,000	16,896.00 m ³	\$174,000	21,120.00 m ³	\$232,000
9. Silo Unloading Conveyors		35.20 m ³ /hr	\$ 28,000	52.80 m ³ /hr	\$ 29,600	70.40 m ³ /hr	\$ 31,200	88.00 m ³ /hr	\$ 32,800
10. Vibratory Separator		35.20 m ³ /hr	\$ 9,250	52.80 m ³ /hr	\$ 10,250	70.40 m ³ /hr	\$ 11,250	88.00 m ³ /hr	\$ 12,250
11. Surge Bin		105.60 m ³ /hr	\$ 24,800	158.40 m ³ /hr	\$ 32,600	211.20 m ³ /hr	\$ 40,400	264.00 m ³ /hr	\$ 44,000
12. Hammermill		35.20 m ³ /hr	\$ 38,800	52.80 m ³ /hr	\$ 58,200	70.40 m ³ /hr	\$ 77,600	88.00 m ³ /hr	\$ 77,600
13. Hammermill Feeders		105.60 m ³ /hr	\$ 6,400	158.40 m ³ /hr	\$ 9,600	211.20 m ³ /hr	\$ 12,800	264.00 m ³ /hr	\$ 12,800
14. Pneumatic Conveyor		35.20 m ³ /hr	\$ 64,000	52.80 m ³ /hr	\$ 96,000	70.40 m ³ /hr	\$128,000	88.00 m ³ /hr	\$128,000
TOTAL:			\$423,550		\$559,100		\$637,050		\$714,050

D-1

Table D-1B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 100
RECEIVING, STORING AND PREPROCESSING OF GRAINS
(British Units)**

SECTION 100, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Truck Unloading Bin	1,000 bu	\$ 35,000	1,000 bu	\$ 35,000	1,000 bu	\$ 35,000	1,000 bu	\$ 35,000
2.	Truck Unloading Bin Screw Conveyor	3,000 bu/hr	\$ 8,000	4,500 bu/hr	\$ 9,500	6,000 bu/hr	\$ 11,000	7,500 bu/hr	\$ 12,600
3.	Rail Unloading Bin	2,600 bu	\$ 45,000	2,600 bu	\$ 45,000	2,600 bu	\$ 45,000	2,600 bu	\$ 45,000
4.	Rail Unloading Bin Screw Connector	3,000 bu/hr	\$ 8,500	4,500 bu/hr	\$ 10,150	6,000 bu/hr	\$ 11,800	7,500 bu/hr	\$ 13,500
5.	Screw Connectors to Bucket Elevator	3,000 bu/hr	\$ 11,000	4,500 bu/hr	\$ 13,600	6,000 bu/hr	\$ 16,200	7,500 bu/hr	\$ 18,700
6.	Bucket Elevator	3,000 bu/hr	\$ 27,000	4,500 bu/hr	\$ 33,800	6,000 bu/hr	\$ 41,000	7,500 bu/hr	\$ 48,000
7.	Diverter Valve		\$ 1,800		\$ 1,800		\$ 1,800		\$ 1,800
8.	Storage Silos (10 days)	240,000 bu	\$116,000	360,000 bu	\$174,000	480,000 bu	\$174,000	600,000 bu	\$232,000
9.	Silo Unloading Conveyors	1,000 bu/hr	\$ 28,000	1,500 bu/hr	\$ 29,600	2,000 bu/hr	\$ 31,200	2,500 bu/hr	\$ 32,800
10.	Vibratory Separator	1,000 bu/hr	\$ 9,250	1,500 bu/hr	\$ 10,250	2,000 bu/hr	\$ 11,250	2,500 bu/hr	\$ 12,250
11.	Surge Bin	3,000 bu	\$ 24,800	4,500 bu	\$ 32,600	6,000 bu	\$ 40,400	7,500 bu	\$ 44,000
12.	Hammermill	1,000 bu/hr	\$ 38,800	1,500 bu/hr	\$ 58,200	2,000 bu/hr	\$ 77,600	2,500 bu/hr	\$ 77,600
13.	Hammermill Feeders	1,000 bu/hr	\$ 6,400	1,500 bu/hr	\$ 9,600	2,000 bu/hr	\$ 12,800	2,500 bu/hr	\$ 12,800
14.	Pneumatic Conveyor	1,000 bu/hr	\$ 64,000	1,500 bu/hr	\$ 96,000	2,000 bu/hr	\$128,000	2,500 bu/hr	\$128,000
TOTAL:			\$423,550		\$559,100		\$637,050		\$714,050

Table D-2A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 200
RECEIVING, STORING AND PREPROCESSING OF POTATOES
(Metric Units)**

SECTION 200, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Scales		135 tons	\$ 99,000	135 tons	\$ 99,000	135 tons	\$ 99,000	135 tons	\$ 99,000
2. Potato Cellar		25,900 m ³	\$ 629,800	38,900 m ³	\$ 994,600	51,800 m ³	\$1,259,500	64,800 m ³	\$1,573,700
3. Screw Feed Conveyor		74,000 kg/hr	\$ 28,000	111,230 kg/hr	\$ 42,000	148,000 kg/hr	\$ 56,000	185,230 kg/hr	\$ 70,000
4. Slab Storage		545 m ³	\$ 85,000	815 m ³	\$ 127,500	1,090 m ³	\$ 170,000	1,360 m ³	\$ 212,500
5. Brush Potato Washer		74,000 kg/hr	\$ 204,000	111,230 kg/hr	\$ 306,000	148,000 kg/hr	\$ 357,000	185,230 kg/hr	\$ 459,000
6. Belt Conveyor		74,000 kg/hr	\$ 31,000	111,230 kg/hr	\$ 46,500	148,000 kg/hr	\$ 62,000	185,230 kg/hr	\$ 77,500
7. Feed Bins		140 tons	\$ 34,500	210 tons	\$ 51,750	280 tons	\$ 69,000	350 tons	\$ 86,250
8. Disintegrators		74,000 kg/hr	\$ 54,000	111,230 kg/hr	\$ 67,500	148,000 kg/hr	\$ 87,800	185,230 kg/hr	\$ 108,000
9. Centrifuge		74,000 kg/hr	\$1,000,000	111,230 kg/hr	\$1,500,000	148,000 kg/hr	\$2,000,000	185,230 kg/hr	\$2,500,000
10. Pumps and Motors			\$ 31,300		\$ 46,000		\$ 54,600		\$ 62,700
TOTAL:			\$2,196,600		\$3,280,850		\$4,214,900		\$5,248,650

Table D-2B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 200
RECEIVING, STORING AND PREPROCESSING OF POTATOES
(British Units)**

SECTION 200, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Scales		150 tons	\$ 99,000	150 tons	\$ 99,000	150 tons	\$ 99,000	150 tons	\$ 99,000
2. Potato Cellar		916,000 ft ³	\$ 629,800	1,374,000 ft ³	\$ 994,600	1,832,000 ft ³	\$1,259,500	2,289,000 ft ³	\$1,573,700
3. Screw Feed Conveyor		163,000 lb/hr	\$ 28,000	245,000 lb/hr	\$ 42,000	326,000 lb/hr	\$ 56,000	408,000 lb/hr	\$ 70,000
4. Slab Storage		19,200 ft ³	\$ 85,000	28,800 ft ³	\$ 127,500	38,400 ft ³	\$ 170,000	48,000 ft ³	\$ 212,500
5. Brush Potato Washer		163,000 lb/hr	\$ 204,000	245,000 lb/hr	\$ 306,000	326,000 lb/hr	\$ 357,000	408,000 lb/hr	\$ 459,000
6. Belt Conveyor		163,000 lb/hr	\$ 31,000	245,000 lb/hr	\$ 46,500	326,000 lb/hr	\$ 62,000	408,000 lb/hr	\$ 77,500
7. Feed Bins		3,060 cwt	\$ 34,500	4,590 cwt	\$ 51,750	6,120 cwt	\$ 69,000	7,650 cwt	\$ 86,250
8. Disintegrators		163,000 lb/hr	\$ 54,000	245,000 lb/hr	\$ 67,500	326,000 lb/hr	\$ 87,600	408,000 lb/hr	\$ 108,000
9. Centrifuge		163,000 lb/hr	\$1,000,000	245,000 lb/hr	\$1,500,000	326,000 lb/hr	\$2,000,000	408,000 lb/hr	\$2,500,000
10. Pumps and Motors			\$ 31,300		\$ 46,000		\$ 54,600		\$ 62,700
TOTAL:			\$2,196,600		\$3,280,850		\$4,214,900		\$5,248,650

Table D-3A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 300
COOKING
(Metric Units)**

SECTION 300, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Feed Mix Tank with Mixer	90,840 l	\$ 33,000	136,260 l	\$ 50,000	181,680 l	\$ 53,000	227,100 l	\$ 56,000
2.	Alpha Amylase Tank with Mixer	15,140 l	\$ 9,300	22,716 l	\$ 11,700	30,280 l	\$ 14,000	37,850 l	\$ 16,500
3.	NaOH Tank with Mixer	15,140 l	\$ 9,300	22,710 l	\$ 11,700	30,280 l	\$ 14,000	37,850 l	\$ 16,500
4.	Mash Heater, 105C	---	\$ 8,000	---	\$ 12,000	---	\$ 16,000	---	\$ 20,000
5.	Primary Liquefaction Tanks	3 @ 30,280 l each	\$ 42,000	3 @ 45,420 l each	\$ 56,100	3 @ 60,560 l each	\$ 71,250	3 @ 75,700 l each	\$ 84,750
6.	Mash Heaters, 140C	---	\$ 8,000	---	\$ 12,000	---	\$ 16,000	---	\$ 20,000
7.	Cooking Coils	25.5 m ³	\$ 39,600	38.2 m ³	\$ 40,500	50.8 m ³	\$ 48,130	66.3 m ³	\$ 58,820
8.	Thermocompressor	---	\$250,000	---	\$375,500	---	\$500,000	---	\$625,000
9.	Pumps and Motors		\$ 27,680		\$ 34,900		\$ 41,200		\$ 50,100
TOTAL:			\$426,880		\$604,400		\$773,580		\$947,670

Table D-3B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 300
COOKING
(British Units)**

SECTION 300, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Feed Mix Tank with Mixer	24,000 gal	\$ 33,000	36,000 gal	\$ 50,000	48,000 gal	\$ 53,000	60,000 gal	\$ 56,000
2.	Alpha Amylase Tank with Mixer	4,000 gal	\$ 9,300	6,000 gal	\$ 11,700	8,000 gal	\$ 14,000	10,000 gal	\$ 16,500
3.	NaOH Tank with Mixer	4,000 gal	\$ 9,300	6,000 gal	\$ 11,700	8,000 gal	\$ 14,000	10,000 gal	\$ 16,500
4.	Mash Heaters, 105C	---	\$ 8,000	---	\$ 12,000	---	\$ 16,000	---	\$ 20,000
5.	Primary Liquefaction Tanks	3 @ 8,000 gal each	\$ 42,000	3 @ 12,000 gal each	\$ 56,100	3 @ 16,000 gal each	\$ 71,250	3 @ 20,000 gal each	\$ 84,750
6.	Mash Heaters, 140C	---	\$ 8,000	---	\$ 12,000	---	\$ 16,000	---	\$ 20,000
7.	Cooking Coils	900 ft ³ (10" dia pipe)	\$ 39,600	1,350 ft ³ (12" dia pipe)	\$ 40,500	1,794 ft ³ (16" dia pipe)	\$ 48,130	2,364 ft ³ (16" dia pipe)	\$ 58,820
8.	Thermocompressor	—	\$250,000	—	\$375,500	—	\$500,000	—	\$625,000
9.	Pumps and Motors		\$ 27,680		\$ 34,900		\$ 41,200		\$ 50,100
TOTAL:			\$426,880		\$604,400		\$773,580		\$947,670

Table D-4A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 400
SACCHARIFICATION
(Metric Units)**

SECTION 400, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Atmospheric Flash Tanks	2 @ 2,650 l each	\$ 11,000	2 @ 3,785 l each	\$ 11,600	2 @ 5,300 l each	\$ 12,800	2 @ 6,435 l each	\$ 13,600
2.	Vacuum Flash Tanks	2 @ 5,300 l each	\$ 12,800	2 @ 7,570 l each	\$ 14,000	2 @ 9,840 l each	\$ 15,200	2 @ 12,490 l each	\$ 17,000
3.	Reactor Tanks with Mixers	3 @ 30,280 l each	\$ 42,000	3 @ 45,420 l each	\$ 56,100	3 @ 60,560 l each	\$ 71,250	3 @ 75,700 l each	\$ 84,750
4.	Saccharification Tanks with Mixers	2 @ 90,840 l each	\$ 66,000	2 @ 136,260 l each	\$100,000	2 @ 181,680 l each	\$106,000	2 @ 227,100 l each	\$112,000
5.	HCl Tank with Mixer	15,140 l	\$ 9,300	22,710 l	\$ 11,700	30,280 l	\$ 14,000	37,850 l	\$ 16,500
6.	Glucosylase Tank with Mixer	15,140 l	\$ 9,300	22,710 l	\$ 11,700	30,280 l	\$ 14,000	37,850 l	\$ 16,500
7.	Pumps and Motors		\$ 30,700		\$ 33,000		\$ 46,400		\$ 51,800
TOTAL:			\$181,100		\$238,100		\$279,650		\$312,150

Table D-4B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 400
SACCHARIFICATION
(English Units)**

SECTION 400, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Atmospheric Flash Tanks	2 @ 700 gal each	\$ 11,000	2 @ 1,000 gal each	\$ 11,600	2 @ 1,400 gal each	\$ 12,800	2 @ 1,700 gal each	\$ 13,600
2.	Vacuum Flash Tanks	2 @ 1,400 gal each	\$ 12,800	2 @ 2,000 gal each	\$ 14,000	2 @ 2,600 gal each	\$ 15,200	2 @ 3,300 gal each	\$ 17,000
3.	Reactor Tanks with Mixers	3 @ 8,000 gal each	\$ 42,000	3 @ 12,000 gal each	\$ 56,100	3 @ 16,000 gal each	\$ 71,250	3 @ 20,000 gal each	\$ 84,750
4.	Saccharification Tanks with Mixers	2 @ 24,000 gal each	\$ 66,000	2 @ 36,000 gal each	\$100,000	2 @ 48,000 gal each	\$106,000	2 @ 60,000 gal each	\$112,000
5.	HCL Tank with Mixer		\$ 9,300		\$ 11,700		\$ 14,000		\$ 16,500
6.	Gluc-Amylase Tank with Mixer	4,000 gal	\$ 9,300	6,000 gal	\$ 11,700	8,000 gal	\$ 14,000	10,000 gal	\$ 16,500
7.	Pumps and Motors		\$ 30,700		\$ 33,000		\$ 46,400		\$ 51,800
TOTAL:			\$181,100		\$238,100		\$279,650		\$312,150

Table D-5A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 500
FERMENTATION
(Metric Units)**

SECTION 500, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Fermentation Tanks	8 @ 946,000 l each	\$800,000	12 @ 946,000 l each	\$1,200,000	15 @ 946,000 l each	\$1,500,000	18 @ 946,000 l each	\$1,800,000
2.	Beer Well	946,000 l	\$100,000	946,000 l	\$ 100,000	946,000 l	\$ 100,000	946,000 l	\$ 100,000
3.	Yeast Tank	2 @ 6,400 l each	\$ 13,600	2 @ 9,500 l each	\$ 15,200	2 @ 13,000 l each	\$ 17,000	2 @ 16,300 l each	\$ 19,400
4.	CO ₂ Scrubber	70 m ³ /min	\$ 9,800	110 m ³ /min	\$ 11,200	142 m ³ /min	\$ 13,650	177 m ³ /min	\$ 14,900
5.	Pumps and Motors		\$ 36,750		\$ 49,800		\$ 64,600		\$ 71,750
	TOTAL:		\$960,150		\$1,376,200		\$1,695,250		\$2,006,050

Table D-5B

SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 500
FERMENTATION
(British Units)

SECTION 500, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Fermentation Tanks	8 @ 250,000 gal each	\$800,000	12 @ 250,000 gal each	\$1,200,000	15 @ 250,000 gal each	\$1,500,000	18 @ 250,000 gal each	\$1,800,000
2.	Beer Well	250,000 gal	\$100,000	250,000 gal	\$ 100,000	250,000 gal	\$ 100,000	250,000 gal	\$ 100,000
3.	Yeast Tank	2 @ 1,700 gal	\$ 13,600	2 @ 2,500 gal	\$ 15,200	2 @ 3,400 gal	\$ 17,000	2 @ 4,300 gal	\$ 19,400
4.	CO ₂ Scrubber	2,500 ACFM	\$ 9,800	3,850 ACFM	\$ 11,200	5,000 ACFM	\$ 13,650	6,250 ACFM	\$ 14,900
5.	Pumps and Motors		<u>\$ 36,750</u>		<u>\$ 49,800</u>		<u>\$ 64,600</u>		<u>\$ 71,750</u>
	TOTAL:		\$960,150		\$1,376,200		\$1,695,250		\$2,006,050

Table D-6

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 600
DISTILLATION**

SECTION 600, PLANT SIZE:		76 M Liters (20 MM Gallons) Cost	114 M Liters (30 MM Gallons) Cost	152 M Liters (40 MM Gallons) Cost	189 M Liters (50 MM Gallons) Cost
<u>Item</u>					
1.	Distillation Column	Package Price	Package Price	Package Price	Package Price
2.	Preheaters (3)	Package Price	Package Price	Package Price	Package Price
3.	Reflux Drum	Package Price	Package Price	Package Price	Package Price
4.	Reboilers (2)	Package Price	Package Price	Package Price	Package Price
5.	Coolers (2)	Package Price	Package Price	Package Price	Package Price
6.	Fusel Oil Washer	Package Price	Package Price	Package Price	Package Price
7.	Pumps (3)	Package Price	Package Price	Package Price	Package Price
TOTAL:		\$1,000,000	\$1,410,000	\$1,825,000	\$2,250,000

Table D-7

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 700
DEHYDRATION**

SECTION 700, PLANT SIZE:		76 M Liters (20 MM Gallons) Cost	114 M Liters (30 MM Gallons) Cost	152 M Liters (40 MM Gallons) Cost	189 M Liters (50 MM Gallons) Cost
Item					
1.	Dehydration Column	Package Price	Package Price	Package Price	Package Price
2.	Coolers (3)	Package Price	Package Price	Package Price	Package Price
3.	Dehydration Agent Separator	Package Price	Package Price	Package Price	Package Price
4.	Hydrocarbon Stripper	Package Price	Package Price	Package Price	Package Price
5.	Ethanol Accumulator	Package Price	Package Price	Package Price	Package Price
6.	Reboilers (3)	Package Price	Package Price	Package Price	Package Price
7.	Preheater	Package Price	Package Price	Package Price	Package Price
8.	Pumps (6)	Package Price	Package Price	Package Price	Package Price
TOTAL:		\$1,000,000	\$1,410,000	\$1,825,000	\$2,250,000

Table D-8A

SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 800
DDG PROCESSING
(Metric Units)

SECTION 800, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Whole Stillage Tank		54,500 l	\$ 21,700	81,700 l	\$ 30,000	109,000 l	\$ 48,000	136,000 l	\$ 50,000
2. Thin Stillage Tank		54,500 l	\$ 21,700	81,700 l	\$ 30,000	109,000 l	\$ 48,000	136,000 l	\$ 50,000
3. Centrifuges		1,500 l/min	\$ 550,000	2,300 l/min	\$ 825,000	3,000 l/min	\$1,100,000	3,800 l/min	\$1,200,000
4. Turbulizer		38,100 kg/hr	\$ 30,300	57,200 kg/hr	\$ 45,450	76,300 kg/hr	\$ 60,600	95,300 kg/hr	\$ 75,700
5. Packaged Turbo-Dryer		---	\$ 400,000	---	\$ 600,000	---	\$ 800,000	---	\$ 954,000
6. Airlock		---	\$ 17,000	---	\$ 25,500	---	\$ 34,000	---	\$ 42,400
7. Dryer Blower		35 m ³ /hr	\$ 40,000	53 m ³ /hr	\$ 60,000	70 m ³ /hr	\$ 80,000	88 m ³ /hr	\$ 99,000
8. Storage Bin		35 m ³ /hr	\$ 35,000	53 m ³ /hr	\$ 38,300	70 m ³ /hr	\$ 41,700	88 m ³ /hr	\$ 45,000
9. Hammer Mill		35 m ³ /hr	\$ 12,700	53 m ³ /hr	\$ 19,100	70 m ³ /hr	\$ 25,400	88 m ³ /hr	\$ 31,800
10. Cooler		---	\$ 170,000	---	\$ 255,000	---	\$ 340,000	---	\$ 424,000
11. Cooler Blower		35 m ³ /hr	\$ 26,500	53 m ³ /hr	\$ 40,000	70 m ³ /hr	\$ 53,000	88 m ³ /hr	\$ 66,000
12. Pumps and Motors			\$ 6,400		\$ 8,200		\$ 9,250		\$ 10,860
TOTAL:			\$1,331,300		\$1,876,550		\$2,639,950		\$3,048,760

Table D-8B

SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 800
DDG PROCESSING
(British Units)

SECTION 800, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Whole Stillage Tank		14,400 gal	\$ 21,700	21,600 gal	\$ 30,000	28,800 gal	\$ 48,000	36,000 gal	\$ 50,000
2. Thin Stillage Tank		14,400 gal	\$ 21,700	21,600 gal	\$ 30,000	28,800 gal	\$ 48,000	36,000 gal	\$ 50,000
3. Centrifuges		400 GPM	\$ 550,000	600 GPM	\$ 825,000	800 GPM	\$1,100,000	1,000 GPM	\$1,200,000
4. Turbulizer		84,000 lb/hr	\$ 30,300	126,000 lb/hr	\$ 45,450	168,000 lb/hr	\$ 60,600	210,000 lb/hr	\$ 75,700
5. Packaged Turbo-Dryer			\$ 400,000		\$ 600,000		\$ 800,000		\$ 954,000
6. Airlock		---	\$ 17,000	---	\$ 25,500	---	\$ 34,000	---	\$ 42,400
7. Dryer Blower		1,000 bu/hr	\$ 40,000	1,500 bu/hr	\$ 60,000	2,000 bu/hr	\$ 80,000	2,500 bu/hr	\$ 99,000
8. Storage Bin		1,000 bu	\$ 35,000	1,500 bu	\$ 38,300	2,000 bu	\$ 41,700	2,500 bu	\$ 45,000
9. Hammer Mill		1,000 bu/hr	\$ 12,700	1,500 bu/hr	\$ 19,100	2,000 bu/hr	\$ 25,400	2,500 bu/hr	\$ 31,800
10. Cooler		---	\$ 170,000	---	\$ 255,000	---	\$ 340,000	---	\$ 424,000
11. Cooler Blower		1,000 bu/hr	\$ 26,500	1,500 bu/hr	\$ 40,000	2,000 bu/hr	\$ 53,000	2,500 bu/hr	\$ 66,000
12. Pumps and Motors			\$ 6,400		\$ 8,200		\$ 9,250		\$ 10,860
TOTAL:			\$1,331,300		\$1,976,550		\$2,639,950		\$3,048,760

Table D-9A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 900
THIN STILLAGE PROCESSING
(Metric Units)**

SECTION 900, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Spray-Film Evaporator		72,575 kg/hr	Package Price	108,864 kg/hr	Package Price	145,152 kg/hr	Package Price	181,440 kg/hr	Package Price
2. Forced Circulation Finish Concentrator		11,794 kg/hr	Package Price	17,690 kg/hr	Package Price	23,587 kg/hr	Package Price	29,484 kg/hr	Package Price
3. Centrifugal Compressor		1,920 kW	Package Price	2,880 kW	Package Price	3,840 kW	Package Price	4,800 kW	Package Price
4. Condensate Tank		75,700 l	\$ 28,250	113,550 l	\$ 48,000	151,400 l	\$ 51,000	189,250 l	\$ 54,000
5. Evaporator Pump			Package Price		Package Price		Package Price		Package Price
6. Heat Exchanger			Package Price		Package Price		Package Price		Package Price
7. Flash Tank			Package Price		Package Price		Package Price		Package Price
8. Condensate Pump			\$ 4,520		\$ 5,120		\$ 6,780		\$ 9,390
*Package Price			\$3,000,000		\$4,500,000		\$6,000,000		\$7,500,000
TOTAL COST:			\$3,032,770		\$4,553,120		\$6,057,780		\$7,563,390

Table D-9B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 900
THIN STILLAGE PROCESSING
(British Units)**

SECTION 900, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Spray-Film Evaporator		160,000 lb/hr	Package Price	240,000 lb/hr	Package Price	320,000 lb/hr	Package Price	400,000 lb/hr	Package Price
2. Forced Circulation Finish Concentrator		26,000 lb/hr	Package Price	39,000 lb/hr	Package Price	52,000 lb/hr	Package Price	65,000 lb/hr	Package Price
3. Centrifugal Compressor		2,575 hp	Package Price	3,862 hp	Package Price	5,150 hp	Package Price	6,437 hp	Package Price
4. Condensate Tank		20,000 gal	\$ 28,250	30,000 gal	\$ 48,000	40,000 gal	\$ 51,000	50,000 gal	\$ 54,000
5. Evaporator Pump			Package Price		Package Price		Package Price		Package Price
6. Heat Exchanger			Package Price		Package Price		Package Price		Package Price
7. Flash Tank			Package Price		Package Price		Package Price		Package Price
8. Condensate Pump			\$ 4,520		\$ 5,120		\$ 6,780		\$ 9,390
*Package Price			\$3,000,000		\$4,500,000		\$6,000,000		\$7,500,000
TOTAL COST:			\$3,032,770		\$4,553,120		\$6,057,780		\$7,563,390

Table D-10A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 1000
PRODUCT AND BYPRODUCT STORAGE
(Metric Units)**

SECTION 1000, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Day Tank (12 hours)	2 @ 132,475 l	\$100,000	2 @ 208,175 l	\$110,000	2 @ 283,875 l	\$ 120,000	2 @ 359,575 l	\$ 130,000
2.	Fusel Oil Tank (30 days)	15,140 l	\$ 9,000	22,710 l	\$ 11,000	30,280 l	\$ 12,600	38,750 l	\$ 14,000
3.	Ethanol Storage Tanks (30 days)	7,570,000 l	\$336,000	11,355,000 l	\$475,000	15,140,000 l	\$ 611,000	18,925,000 l	\$ 738,000
4.	Aldehyde Tank (30 days)	22,710 l	\$ 11,000	30,280 l	\$ 12,600	41,635 l	\$ 15,200	49,205 l	\$ 17,000
5.	Denaturant Tank	74,700 l	\$ 23,250	113,550 l	\$ 32,000	151,400 l	\$ 50,000	189,250 l	\$ 55,000
6.	Packaged DDG Bin	60 m ³	\$ 17,250	89 m ³	\$ 21,900	119 m ³	\$ 26,500	149 m ³	\$ 31,000
7.	Packaged DDG Silos	6,680 m ³	\$ 99,900	10,000 m ³	\$130,000	13,350 m ³	\$ 161,300	16,700 m ³	\$ 192,000
8.	Pumps and Motors		\$ 18,900		\$ 19,700		\$ 20,490		\$ 22,500
TOTAL:			\$615,300		\$812,200		\$1,017,090		\$1,199,500

Table D-10B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR SECTION 1000
PRODUCT AND BYPRODUCT STORAGE
(British Units)**

SECTION 1000, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Day Tank (12 hours)		2 @ 35,000 gal each	\$100,000	2 @ 55,000 gal each	\$110,000	2 @ 75,000 gal each	\$118,000	2 @ 95,000 gal each	\$ 130,000
2. Fusel Oil Tank (30 days)		4,000 gal	\$ 9,300	6,000 gal	\$ 11,700	8,000 gal	\$ 14,000	10,000 gal	\$ 16,500
3. Ethanol Storage Tanks (30 days)		2 M gal	\$336,000	3 M gal	\$475,000	4 M gal	\$ 611,000	5 M gal	\$ 738,000
4. Aldehyde Tank (30 days)		6,000 gal	\$ 11,700	8,000 gal	\$ 14,000	11,000 gal	\$ 17,600	13,000 gal	\$ 20,000
5. Denaturant Tank		20,000 gal	\$ 28,250	30,000 gal	\$ 48,000	40,000 gal	\$ 51,000	50,000 gal	\$ 54,000
6. Packaged DDG Bin		2,100 ft ³	\$ 17,250	3,150 ft ³	\$ 21,900	4,200 ft ³	\$ 26,500	5,250 ft ³	\$ 31,000
7. Packaged DDG Silos		236,000 ft ³	\$ 99,900	354,000 ft ³	\$130,000	472,000 ft ³	\$ 161,000	590,000 ft ³	\$ 192,000
8. Pumps and Motors			<u>\$ 18,900</u>		<u>\$ 19,700</u>		<u>\$ 20,490</u>		<u>\$ 22,500</u>
TOTAL:			\$615,300		\$812,200		\$1,017,090		1,199,500

Table D-11A

**SAN LUIS VALLEY, COLORADO CAPITAL COST MATERIALS LIST
FOR WASTEWATER TREATMENT EQUIPMENT
(Metric Units)**

SECTION 1100, PLANT SIZE:		76 M Liters		114 M Liters		152 M Liters		189 M Liters	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Settling and Aeration Basins	8.8 M l	\$ 77,000	13.4 M l	\$ 101,000	17.6 M l	\$ 130,000	22.2 M l	\$ 161,000
2.	Dissolved Air Flotation Unit	1,150.0 lpm	\$ 269,800	1,700.0 lpm	\$ 376,000	2,300.0 lpm	\$ 456,000	2,850.0 lpm	\$ 521,000
3.	Activated Sludge Treatment Unit	1,150.0 lpm	\$ 710,000	1,700.0 lpm	\$ 990,000	2,300.0 lpm	\$1,200,000	2,850.0 lpm	\$1,375,000
4.	Gravity Clarifier	1,150.0 lpm	\$ 40,000	1,700.0 lpm	\$ 50,000	2,300.0 lpm	\$ 58,000	2,850.0 lpm	\$ 65,000
5.	Sulfonation Unit	1,150.0 lpm	\$ 85,200	1,700.0 lpm	\$ 118,000	2,300.0 lpm	\$ 141,000	2,850.0 lpm	\$ 164,000
TOTAL:			\$1,182,000		\$1,635,000		\$1,985,000		\$2,286,000

Table D-11B

**SAN LUIS VALLEY, COLORADO CAPITAL COST MATERIALS LIST
FOR WASTEWATER TREATMENT EQUIPMENT
(British Units)**

SECTION 1100, PLANT SIZE:		20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
Item		Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1.	Settling and Aeration Basins	2.3 MM gal	\$ 77,000	3.5 MM gal	\$ 101,000	4.6 MM gal	\$ 130,000	5.8 MM gal	\$ 161,000
2.	Dissolved Air Flotation Unit	300.0 gpm	\$ 269,800	450.0 gpm	\$ 376,000	600.0 gpm	\$ 456,000	750.0 gpm	\$ 521,000
3.	Activated Sludge Treatment Unit	300.0 gpm	\$ 710,000	450.0 gpm	\$ 990,000	600.0 gpm	\$1,200,000	750.0 gpm	\$1,375,000
4.	Gravity Clarifier	300.0 gpm	\$ 40,000	450.0 gpm	\$ 50,000	600.0 gpm	\$ 58,000	750.0 gpm	\$ 65,000
5.	Sulfonation Unit	300.0 gpm	\$ 85,200	450.0 gpm	\$ 118,000	600.0 gpm	\$ 141,000	750.0 gpm	\$ 164,000
TOTAL:			\$1,182,000		\$1,635,000		\$1,985,000		\$2,286,000

D-20

Table D-12A

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR
THE GEOTHERMAL SYSTEM COMPONENTS
(Metric Units)**

Item	76 M Liters		114 M Liters		152 M Liters		189 M Liters	
	Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Reactor Clarifier	420,000 kg/hr	\$302,500	628,000 kg/hr	\$ 454,000	839,000 kg/hr	\$ 605,000	1,045,000 kg/hr	\$ 758,000
2. Multimedia Gravity Filter	420,000 kg/hr	\$120,700	628,000 kg/hr	\$ 181,000	839,000 kg/hr	\$ 241,000	1,045,000 kg/hr	\$ 302,000
3. Thickener	420,000 kg/hr	\$ 52,000	628,000 kg/hr	\$ 78,000	839,000 kg/hr	\$ 104,000	1,045,000 kg/hr	\$ 130,000
4. Filter Press	420,000 kg/hr	\$ 23,000	628,000 kg/hr	\$ 34,500	839,000 kg/hr	\$ 46,000	1,045,000 kg/hr	\$ 57,000
5. Insulation	---	\$ 87,000	---	\$ 130,000	---	\$ 174,000	---	\$ 217,000
6. Sludge Pump	---	\$ 1,800	---	\$ 2,700	---	\$ 3,600	---	\$ 4,500
7. First Stage Flash Separator Vessel	2 @ 485,000 kg/hr	\$166,000	2 @ 726,000 kg/hr	\$ 249,000	2 @ 970,000 kg/hr	\$ 332,000	2 @ 1,207,000 kg/hr	\$ 415,000
8. Second Stage Flash Separator Vessel	2 @ 449,000 kg/hr	\$210,000	2 @ 672,000 kg/hr	\$ 315,000	2 @ 898,000 kg/hr	\$ 420,000	2 @ 1,116,000 kg/hr	\$ 525,000
TOTAL:		\$963,000		\$1,444,200		\$1,925,600		\$2,406,500

Table D-12B

**SAN LUIS VALLEY, COLORADO MAJOR EQUIPMENT COST ESTIMATE FOR
THE GEOTHERMAL SYSTEM COMPONENTS
(British Units)**

Item	20 MM Gallons		30 MM Gallons		40 MM Gallons		50 MM Gallons	
	Capacity	Cost	Capacity	Cost	Capacity	Cost	Capacity	Cost
1. Reactor Clarifier	925,000 lb/hr	\$302,500	1,385,00 lb/hr	\$ 454,000	1,850,000 lb/hr	\$ 605,000	2,300,000 lb/hr	\$ 756,000
2. Multimedia Gravity Filter	925,000 lb/hr	\$120,750	1,385,000 lb/hr	\$ 181,000	1,850,000 lb/hr	\$ 241,000	1,300,000 lb/hr	\$ 302,000
3. Thickener	925,000 lb/hr	\$ 52,000	1,385,000 lb/hr	\$ 78,000	1,850,000 lb/hr	\$ 104,000	2,300,000 lb/hr	\$ 130,000
4. Filter Press	925,000 lb/hr	\$ 23,000	1,385,000 lb/hr	\$ 34,500	1,850,000 lb/hr	\$ 46,000	2,300,000 lb/hr	\$ 37,000
5. Insulation	---	\$ 87,000	---	\$ 130,000	---	\$ 174,000	---	\$ 217,000
6. Sludge Pump	---	\$ 1,800	---	\$ 2,700	---	\$ 3,600	---	\$ 4,500
7. First Stage Flash Separator Vessel	2 @ 1,070,000 lb/hr	\$166,000	2 @ 1,600,000 lb/hr	\$ 249,000	2 @ 2,140,000 lb/hr	\$ 332,000	2 @ 2,660,000 lb/hr	\$ 415,000
8. Second Stage Flash Separator Vessel	2 @ 990,000 lb/hr	\$210,000	2 @ 1,480,000 lb/hr	\$ 315,000	2 @ 1,980,000 lb/hr	\$ 420,000	2 @ 2,460,000 lb/hr	\$ 525,000
TOTAL		\$963,000		\$1,444,200		\$1,925,600		\$2,046,500