

A Technical Brief Concerning

Shale Oil Development and Exploration

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Executive Summary

Shale oil is seen by many as America's answer to dependence on importing foreign oil. Shale oil deposits in the western United States are estimated as containing 2 trillion barrels of recoverable oil in the form of kerogen, a precursor to common petroleum and natural gas. Through earth's natural heating and pressurizing, kerogen eventually forms oil and natural gas which are today's main energy source. Over the last hundred years there have been several methods devised to extract petroleum from kerogen, but none have been efficient or economical enough to pursue. However, Shell has been researching a new method of production for several years called the in-situ conversion process that looks promising for the future of shale oil production.

Shale oil has had a long history in the United States. The federal government first realized its usefulness in the early nineteenth century. Since then, several attempts have been made to develop a process that can economically produce shale oil on a commercial scale. The largest project attempted was the Colony II project. It was started by Exxon but after only two years was shut down because the price of foreign oil decreased dramatically.

Shell is currently researching in-situ conversion in the Piceance basin of northwestern Colorado. The process consists of several steps, each of which has their own challenges. What makes their process different than others previously attempted is that the conversion of kerogen into hydrocarbons occurs in place. This is different from previous processes because none of the rock has to be mined. Kerogen is converted into hydrocarbons by heating the ground with large electric heaters. To protect the groundwater around the area of the heated reservoir, a freeze wall is constructed around the site. This freeze wall is impermeable to water and hydrocarbons and keeps the two from mixing preventing contamination. Once the reservoir has reached 700°F the produced hydrocarbons can be extracted from the ground using conventional methods.

A large surface facility is required to separate the hydrocarbons into different products. An 800 MW power plant will also have to be constructed to provide electricity to the heaters and the processing facilities. To transport the products to market two pipelines will have to be built. Analysis shows that the annual product cost is almost \$678 million, which includes extraction costs, operations and maintenance, and production taxes. This facility will require a total capital investment of \$867 million. The entire process will break even in 9.7 years and have a net present worth of \$1.7 billion after 25 years of production.

With the above stated economic incentive, it is necessary to take a deeper look into how to produce shale oil from the ground in a safe and environmentally friendly way. The Shell in-situ conversion process proposes a new technology that would allow the exploration and production of shale oil. This process however has never been proven on a commercial level. Therefore, a study of the technical aspects behind the process including reservoir studies, subsurface operations, and processing facilities must be analyzed through models to determine the feasibility of the project.

Introduction:

The oil shale deposits in western Colorado contain large amounts of oil and gas reserves. Extracting these resources has been a challenge for many investors for the past hundred years. It finally appears that modern technology will allow for the extraction of the oil and gas at an economically feasible price. Also, new initiatives by the federal government have provided money for research into alternative fuels and the Bureau of Land Management has began asking for public input on establishing a land leasing program for shale oil development¹.

In the past, extracting oil from oil shale has not been economically feasible. Test projects and semi-commercial scale plants have been attempted but have all failed due to the high cost of the process and the relatively low price of oil. In the past, oil shale has been extracted from open pits or underground mines and taken to processing facilities. These facilities would crush the rock and feed it into a reactor where it was retorted and the oil and gases extracted. The large open pit mines that were common with these operations posed a huge environmental impact. This process is very energy intensive and its costs are well over that of a conventional barrel of oil.

New methods developed by Shell show promise in reducing the costs of producing shale oil. Their technique is simple in thought. Rather than removing the shale from the ground for processing they do all the processing in place and only extract the valuable oil and gas. To do this, the oil shale is heated in place to between 650 and 700 °F. Then the released oil and gas can be extracted from the ground. This process uses much less energy than mining while recovering more of the available oil. An added

¹ BLM Solicits Public Input To Establish An Oil Shale Leasing Program. (2004). Retrieved 3/9/06 from The Bureau of Land Management. http://www.blm.gov/nhp/news/releases/pages/2004/pr041122_shale.htm

bonus is that the oil removed through in-situ extraction is of a much higher quality than retorted oil and requires less processing before it can be sold.

In-situ conversion of oil shale is not without its risks. Tests have only been conducted on a small experimental scale. The environmental impacts have not been properly assessed. Of the most concern is what affect this process will have on the ground water. Another large variable is the price of oil and gas. Currently, the selling prices of oil and gas are at levels that make in-situ conversion and production profitable. If prices decrease, then the project, that has a very large initial investment, could become uneconomical.

Background and History

It is estimated that 1.5 trillion barrels of oil are located in the oil shale deposits of the western United States. The richest of these deposits is the Piceance Basin located in northwestern Colorado. Merely one thousand square miles of Colorado holds the same amount of oil as all the world's known oil reserves². If the process of extracting the oil could be made economical then it would provide an alternative source of hydrocarbons for several hundred years. The United States would be able to eliminate its dependence on Middle Eastern oil. Thousands of new jobs would be formed and it would provide an economic boost to western Colorado.

The problem is that the oil is trapped inside the pores of the rock, in the form of kerogen. Kerogen is a solid organic material that has an average molecular weight of 3000 and is a precursor of conventional petroleum. To release the available oil the

²Bartis, James T. (2005). Oil Shale Development in The United States, Prospects and Policy Issues. p. 6. Arlington, Virginia: RAND Corp.

kerogen must be heated to between 650 and 700 °F. Oil shale is deposited in a wide range of environments including freshwater ponds, lakes and coastal swamps³. Over time the organic matter is compacted into the shale that is present today. If the conditions of the shale are more intense and last for longer periods of time, the oil shale will be converted to coal or traditional petroleum oil⁴.

Oil shale has had a long and tumultuous history in the United States. It was first realized as a resource of fuel by the federal government in the early twentieth century. At this time the oil shale deposits of western Colorado were incorporated into the United States Naval Petroleum and Oil Shale reserve. These reserves were seen as an emergency source of oil to fuel the navy's ships during a time of war⁵. After a minor boom in the early 1920's interest in oil shale declined due to oil finds in California, Oklahoma, and Texas. It was not until 1944 when the government funded a synthetic fuels initiative that the first test facility opened at Anvil Points, Colorado. After testing three different processes the facility was closed in 1956. In 1964, TOSCO opened a plant that produced a few thousand barrels of oil per day but was closed in 1972 after a total of 270,000 barrels were produced.

The most ambitious oil shale project developed in Colorado has been the Colony II project by Exxon. In 1980 Exxon bought out Arco's stake of a lease in the Colony area of Colorado. The Colony II project was a surface facility that could process 47,000 barrels of oil per day. The shale was mined from an open pit and retorted on the surface.

³ EMD Oil Shale committee. (2005). Oil Shale. Retrieved 3/6/06. from American Association of Petroleum Geologists Energy Minerals Division. http://emd.aapg.org/technical_areas/oil_shale.cfm

⁴ Udall, James R. (2005) The Illusive Bonanza: Oil Shale in Colorado. Retrieved 2/5/06 From EnergyBulletin.net. <http://www.energybulletin.net/11707.html>

⁵ Laherrere, Jean. Review on Oil Shale Data. (2005). P. 2-3. <http://hubbertpeak.com>

On May 2nd, 1982, Exxon closed down the operation on the Colony II project. Decreased demand and the end of oil embargos had reduced the price of oil to the point where surface retorting of oil shale was no longer economical. Exxon lost over \$900 million and over 2,200 people were left unemployed. Many people that live in northwestern Colorado still have animosity towards the energy industry and refer to this day as Black Sunday⁶. In 1997 Shell Oil began tests of an in-situ conversion process at their Mahogany research site⁷. Research at this site is ongoing to this day and the results are encouraging.

Shell's in-situ conversion process is the most promising to date for near term production of oil from shale. In this process the kerogen within the shale is converted to high grade oil and natural gas by slowly heating the rock with electric heaters. Since the rock is not removed from the ground, many of the environmental problems associated with surface processing are avoided. There is no open pit mining, no tailings are created, and water use is minimized.

Site Preparation:

Recovery of oil from shale requires a large amount of site preparation. Although the in-situ process is less intensive on the land than surface processing, many issues must still be addressed before hydrocarbons can be produced. These include establishing the freeze walls, drilling of wells for the heaters and the production wells, removing the groundwater from the site and putting the heaters in place.

⁶ Williamson, Richard. Oil Shale Collapse Preserved Scenic Vistas. (1999). Retrieved 3/8/06 from The Denver Rocky Mountain News.

⁷ Laherrere, Jean. Review on Oil Shale Data. (2005). P. 2-3. <http://hubbertpeak.com>

Drilling Requirements

For every acre 33 wells must be drilled. Number of wells is determined by using a hexagonal pattern of heaters with producing wells located at the center of each hexagon. 25 of these wells are to place heaters into the oil shale. The remaining wells are used to remove the water from the site, extract oil and gas from the reservoir, and return water to the reservoir once production has stopped. Each of these wells is estimated to cost \$80,000. This is considerably less than a traditional well due to the relatively shallow depth, and the lack of a need for logging of the well. Logging is when measuring instruments are lowered into the well to record things like porosity, water saturation and other and other important data. The total drilling cost per tract of land is \$26.4 million.

Freeze Wall Construction and Groundwater Removal

A freeze wall will be placed around the entire site to protect surrounding groundwater and prevent oil and gas from escaping the reservoir. Freeze walls are an emerging technology that is beginning to gain acceptance in the mainstream engineering community. At its final size, one freeze wall will be at least 8 feet thick. The frozen soil that makes up the wall is impermeable to water and hydrocarbons⁸. Therefore, the oil and gas that is produced within the freeze wall are trapped there and the ground water that is outside of the freeze wall cannot come in and be contaminated. Another advantage of freeze walls is that a temporary loss in power will not affect the integrity of the wall.

⁸ Ground Freezing for Environmental Applications. retrieved 2/19/05. From Soil Freeze Technologies. <http://soilfreeze.com/EnvirApp.html>

Freeze walls have been known to last for several weeks without power before thawing becomes an issue⁹.

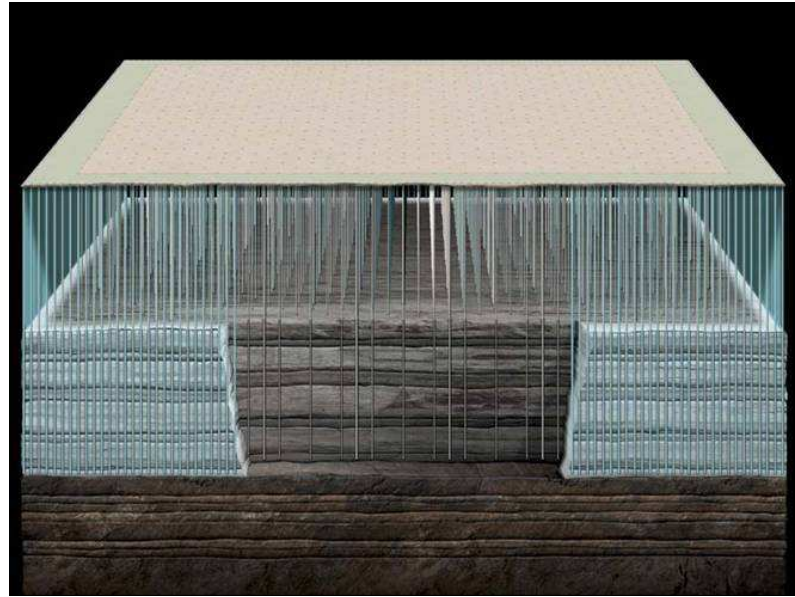


Figure 1: depiction of the site during production

The major cost for the freeze wall is that of refrigeration. A series of double wall pipes must be placed into the ground surrounding the production area. Through these pipes brine at -10 °F is circulated. The cold brine causes the water in the soil to freeze. The major energy costs involved with refrigeration is during the actual formation of the freeze wall.

To calculate the required refrigeration the temperature change and the energy needed for the phase change is accounted for.

$$Q = M * C_p * (T_{final} - T_{initial}) + \Delta H_{freezing} * M_{water} \quad \text{Eq. (1)}$$

Where, C_p = the heat capacity of the shale=1.02 KJ/(Kg*K)¹⁰

⁹ Ground Freezing for Environmental Applications. retrieved 2/19/05. From Soil Freeze Technologies. <http://soilfreeze.com/aboutGF.html>

T_f =the final temperature of the shale=10 °F

T_i =the initial temperature of the shale=150 °F

$\Delta H_{\text{freezing}}=334 \text{ j/gram}$

$M_{\text{water}}=1.2\text{E}8 \text{ kg}$

The total cost of this refrigeration is \$3.2 million per day. It should be noted that this cost is only occurred during the initial period while the freeze wall is being established. To maintain the freeze wall is considerably less cost.

$$Q = -k \frac{\partial T}{\partial z} \quad \text{Eq. (2)}$$

K =thermal conductivity of the shale=0.950j/(M*K*sec)

$\frac{\partial T}{\partial Z}$ = Temperature gradient at the freeze wall =.0709 K/ft

It is important to note that there will also be water trapped within the freeze wall. This water will have to be removed before the heating of the reservoir begins. To remove this water, centrifugal pumps will be attached to the production wells and the water will be pumped out. If the capacity to remove this water is divided between all of the production wells then each pump must handle 1.6 million gallons of water per hour. This is based on an estimate of 2 barrels of water for every barrel of recoverable oil¹¹. At this

¹⁰ Feng H.Y., Pan Zhenglu, Smith, J. M. (1985). Rates of Pyrolysis of Colorado Oil Shale. AiChE Journal, 31, 721-728.

¹¹ Bartis, James T. (2005). Oil Shale Development in The United States, Prospects and Policy Issues. p. 6. Arlington, Virginia: RAND Corp.

rate the water will be removed within 2 weeks. A pump of this capacity costs in the neighborhood of \$23,000¹². The total cost for pumps will be \$1.84 million.

Heater Design and Costs:

During the in-situ conversion process, the reservoir must be heated to a temperature between 650 and 700 degrees Fahrenheit¹³. This is the temperature at which kerogen begins breaking down into lighter hydrocarbons such as oil and natural gas. To accomplish this, electric resistance heaters will be used. Over an acre there will need to be approximately 25 heaters¹⁴. They will be placed evenly in a hexagonal pattern, 60 feet apart. To determine the power needed for each heater the total heat needed must be calculated.

$$Q = mC_p(T_f - T_i) - k \frac{\partial T}{\partial z} \quad \text{Eq. (3)}$$

Where, m = the mass of shale to be heated

C_p = the heat capacity of the shale = 1.02 KJ/(Kg*K)¹⁵

T_f = the final temperature of the shale = 700 °F

T_i = the initial temperature of the shale = 150 °F

K = thermal conductivity of the shale = 0.950 j/(M*K*sec)

$\frac{\partial T}{\partial Z}$ = Temperature gradient at the freeze wall = .0709 K/ft

¹² Peters, Max S., Timmerhaus, Klaus D., West, Ronald E., (2003). Plant Design and Economics for Chemical Engineers. Fig. 12-20. New York. McGraw-Hill.

¹³ Bartis, James T. (2005). Oil Shale Development in The United States, Prospects and Policy Issues. p. 17. Arlington, Virginia: RAND Corp.

¹⁴ Bartis, James T. (2005). Oil Shale Development in The United States, Prospects and Policy Issues. p. 17. Arlington, Virginia: RAND Corp.

¹⁵ Feng H.Y., Pan Zhenglu, Smith, J. M. (1985). Rates of Pyrolysis of Colorado Oil Shale. AiChE Journal, 31, 721-728.

The mass is calculated using Equation 4.

$$m = \rho * V \quad \text{eq. (4)}$$

where: ρ = the density of the shale = 2400 Kg/m³

V = volume of the shale to be heated

The heaters will be built from a six inch steel pipe that contains an electric heating

element. A Chromel AA element has been chosen for the design because of its self regulating properties at 1500 °F. This alloy is referred to as self regulating because the resistance of the material changes with temperature in such a way that it maintains a constant temperature. This is important because if the heater does not have a self regulating

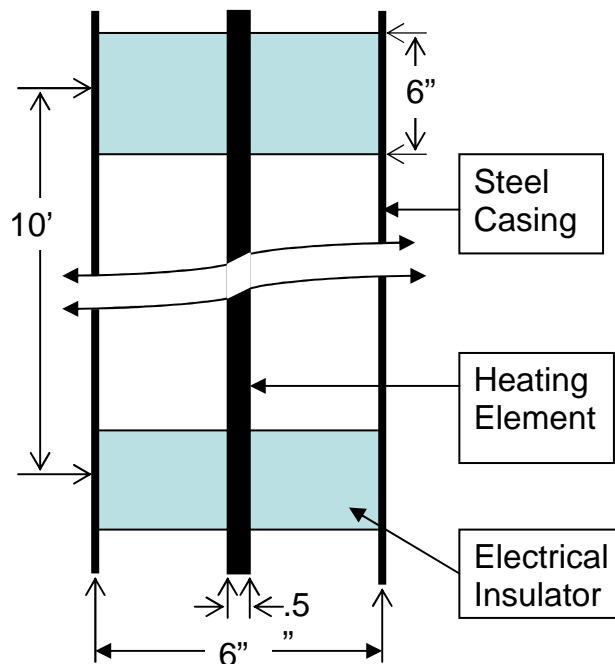


Figure 2: a schematic of what the heaters will look like

property there is the possibility that it will overheat and burn itself out. The element must be insulated from the surrounding pipe by ceramic insulators. Each heater will be capable of outputting a minimum of 165 KW of energy. They are designed to operate at 480 VAC. This will allow for an amp rating of 350 A while still maintaining the proper heat output. The total material cost for the heaters is approximately \$80,000.

Table 1: Summary of material costs for the construction of electric heaters

Component	Specification	Cost
Casing	6" diameter @ \$20.00/ft	\$50,000.00
Element	Chromel AA wire @ \$20.00/ft	\$10,000.00
Insulator	250 @ \$14 ea	\$3,500.00
Instrumentation/ Control	.36 of the total cost	\$12,000.00
Labor	35\$/hr skilled labor	\$1,750.00
Total:		\$80,000.00

AC current was chosen because the switching equipment is readily available and easily replaceable. It may be that this is not feasible due to current densities but this has not been studied in detail.

The heaters will be maintained at a temperature of 1,500°F. This temperature was chosen so that the overall temperature of the reservoir will reach 700°F in the amount of time that we found in our research. Any vertical variations in temperature will be managed by the self regulating nature of the heater. It is important to note that current will be passing through the upper portion of the heater. This will cause some losses but they are not taken into account in the energy calculations that have been done.

Production Schedule

It is not known how long this process will be the most feasible one for recovery of shale oil. A life of 25 years has been chosen for the project. To insure a consistent production volume over the 25 year life of the project, it is important to have a proper production schedule. Each acre of oil shale bearing land is estimated to contain 2.5 million barrels of recoverable oil¹⁶. For this project calculations will be done with 10 acre

¹⁶ Bartis, James T. (2005). Oil Shale Development in The United States, Prospects and Policy Issues. p. 7. Arlington, Virginia: RAND Corp.

tracts of land. Each tract will produce 40,000 barrels of oil a day. At this rate each tract will only produce for 2 years. Due to this short cycle a new plot of land will have to begin production every year to maintain a steady output of products.

There is an extended period of preparation that goes into each tract of land before it can go into production. Nearly 330 wells must be drilled, the freeze wall must be established, water must be removed, and the heaters must be lowered into place. After the site is completely prepared the heaters can be activated and heating can begin. The heating process is a slow one, with a rate of only .43 degrees Fahrenheit per day. This was established from our 1-D temperature profile. For the producing wells to reach 700 degrees Fahrenheit the heaters must operate for 3.5 years. This can be adjusted by adding or reducing the number of heaters and keeping the heaters at a higher or lower temperature. It is important to note though that this would affect the composition of the products from the reservoir.

Once a tract of land stops producing there is still a considerable amount of effort needed to return the land to its original condition. The first thing to be done is to inject water back into the reservoir. This cools the remaining shale and removes any free hydrocarbons remaining in the reservoir. Water injection is estimated to last upwards of 6 months. After this true land reclamation can begin. Over the next 6 months the freeze wall is allowed to thaw and the surface is returned to its original condition.

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
Site 1	8 Months	36 Months		24 Months		6	6		
Site 2		13 Months	36 Months		24 Months		6	6	
Site 3			13 Months	36 Months		24 Months		6	6

	site preparation: drilling wells, laying the pipe, and freeze wall formation
	heating only
	production while refrigeration and temperature is maintained
	water injection
	site reclamation

Figure 3: Schedule for the preparation and production of land tracts.

To achieve a consistent output of oil production there must be at least 2 tracts of land producing at any one time. By staggering the time that each tract is begun by one year then at any time there will be two tracts in production. Figure 3 illustrates the overlap of tracts while they are in development, producing, and being reclaimed. New tracts will begin producing at the time when an old tract quits producing. It should be noted that the production of oil from oil shale begins very strong, stays at a steady state of production, and then quickly declines¹⁷.

Temperature Profiles

Methods: One Dimensional Profile

When oil shale is heated underground, the solid kerogen material begins to turn into liquid and vapors due to the cracking of large hydrocarbon compounds. This reaction creates smaller hydrocarbons that are able to move through the pores of the shale rock which were once filled with solid kerogen material. Eventually, when a production

¹⁷Seebach, Linda. (2005). Seebach: Shell's ingenious approach to oil shale is pretty slick. Retrieved 2/17/05 from Rockymountainnews.com.
http://www.rockymountainnews.com/drmn/news_columnists/article/0,1299,DRMN_86_4051709,00.html

well of lower pressure is opened in the reservoir, the newly formed hydrocarbons will flow out due to the pressure differential.

It is necessary for the production of the oil shale to know which hydrocarbons will be released from the kerogen at different times during the heating process of the shale rock. This information allows the composition of the fluid to be predicted. The first step in finding the composition of the producing fluid is determining what the temperature profile of the reservoir is over the time of heating. Different amounts of hydrocarbons are cracked from the kerogen at different temperatures. This means that at set distances away from the heaters and freeze wall, certain hydrocarbons will be produced and later will flow out of the production wells.

The temperature profile for the reservoir is generated from several assumptions due to the complexity of the reservoir and heating process. First, the heat transfer through the reservoir in the one dimensional model is only being considered to be from the heater to the reservoir rock and perpendicular to the heater. This is the area where the production well will be placed. The temperature profile for this location can be created from an unsteady state one dimensional heat balance on the reservoir. Equation 5 below is the partial differential equation that describes the heat transferring away from each heater into the reservoir rock when there is no reaction taking place in the reservoir, meaning that no kerogen is cracking into smaller hydrocarbons.

$$\rho C_p \frac{\partial T}{\partial t} = k \frac{\partial^2 T}{\partial z^2} \quad \text{eq. (5)}$$

Where: T = temperature

z = distance from heater
 ρ = density
 C_p = specific heat
 k = thermal conductivity

Along with the heat transfer from the reservoir, there is also heat generated from the exothermic cracking of kerogen into smaller hydrocarbon chains. The heat generated from this process is dependent on the concentration of kerogen in the reservoir rock as well as the heat of reaction of the cracking process. Equation 5 has been modified to include these terms and takes the form of Equation 6 displayed below.

$$\frac{\partial T}{\partial t} = \alpha \frac{\partial^2 T}{\partial z^2} - \frac{q}{\rho C_p} \quad \text{eq.(6)}$$

Where: α = thermal diffusivity

q = heat generated by the exothermic cracking of kerogen
 ρ = density
 C_p = specific heat
 T = temperature

The heat generated from the exothermic cracking of kerogen is dependent on the concentration of kerogen found in the reservoir. Therefore, the equation displayed above must be integrated simultaneously with an equation that calculates the change in concentration over the change in time of kerogen in the reservoir. This change in concentration is calculated using Equation 7 below.

$$\frac{dC_k}{dt} = -Ae^{\left(\frac{-E_a}{RT}\right)} C_k \quad \text{eq. (7)}$$

Equations 6 and 7 above must be integrated simultaneously. This integration is carried out using a finite difference method in Excel. The two equations above are combined to give Equation 8 below, which is the finite difference representation of the previous equations.

$$T_i |_{t+\Delta t} - T_i |_t = \frac{\alpha \Delta t}{\Delta x^2} (T_{i+1} |_t + T_{i-1} |_t) - \frac{2\alpha \Delta t}{\Delta x^2} T_i |_t - \frac{A t e^{\left(\frac{-E_a}{RT}\right)} C_k (-\Delta H_{rx})}{\rho C_p} \quad \text{eq. (8)}$$

Where: T= temperature

α = thermal diffusivity of shale oil

Δt = time step

Δx = change in distance

A = frequency factor

E_a = activation energy

R = gas constant

ΔH_{rx} = heat of reaction

ρ = density

C_k = concentration of kerogen

C_p = specific heat

The above equation calculates the temperature at location i away from the heater and at time t+ Δt . The terms on the left side of the equation account for the heat at a certain distance in the reservoir and at a certain time. The first two terms on the right hand side of the equation account for the heat conducted throughout the reservoir. The last term in the equation gives the heat generated by the exothermic cracking of the kerogen. The concentration of kerogen is constantly changing as the reaction occurs and

can be calculated using Equation 9. This equation can be substituted into Equation 8 so that they are calculated simultaneously.

$$C_k |_{t+\Delta t} = k\Delta t e^{\left(\frac{-E_a}{RT}\right)} + C_k |_t \quad \text{eq. (9)}$$

Where: k = rate constant

Δt = time step

E_a = activation energy

R = gas constant

T = temperature

$C_k|_t$ = concentration at time t

The rate constant that is found in the concentration equation can be described by Equation 10 below.

$$k = A e^{\left(\frac{-E_a}{RT}\right)} \quad \text{eq. (10)}$$

where: A = frequency factor

E_a = activation energy

R = gas constant

T = temperature

The rate constant equation takes into consideration the activation energy for kerogen. This equation helps determine how quickly the initial concentration of kerogen is cracked. With the change in temperature and time, more kerogen will be cracked, reducing the overall kerogen concentration in the reservoir.

The properties of the kerogen and reservoir rock must be provided to achieve the correct temperatures at different positions in the reservoir at different times. There are several assumptions associated with using these properties. First, the reservoir

temperature is assumed to be 150°F. This temperature was derived from using the geothermal gradient of the Colorado area where the shale oil will be being produced from. This gradient is 15.4°C/kilometer¹⁸. Another assumption is that the specific heat of the source rock can be held constant and represents the entire reservoir. Because the vast majority of space in the reservoir is consumed by source rock, this assumption can be made. This rock will not be changing during the heating process but the pores will. The small pores of the rock contain the kerogen which will be reacting. Because it makes up such a small portion, the affect of the reaction is assumed to not have a large enough affect on the overall specific heat of the reservoir. The spacing between heaters was calculated to be sixty feet which is based off of an average amount of twenty heaters per acre and a hexagonal pattern.¹⁹ All of the properties for the reservoir are listed in table 2 below²⁰.

¹⁸ Well 272 on Geothermal map of Colorado (1982). Depth 1768m

¹⁹ Bartis, James T. Oil Shale Development in the United States: Prospects and Policy Issues. Rand Corporation: Santa Monica, 2005. 17.

²⁰ Pan, Zhenglu, H.Y Feng and J.M Smith. "Rates of Pyrolysis of Colorado Oil Shale." AICHE Journal 31.5 (1985): 721-728.

Table 2: Reservoir and Kerogen Properties. Used in creation of temperature one dimensional profiles.

Temperature Profile with Cracking		
Variable	Unit	Input
Length Between Heaters	ft	60
Segment lengths	ft	1.463414634
Activation energy	kJ/mol	2000
frequency factor	1/hr	1.08E+17
Gas Constant	kJ/mol*K	0.008314
alpha	ft ² /hr	0.008
Temperature of heater	F	1500
Temperature of ice wall	F	32
Initial reservoir temperature	F	150
Density of rock	kg/m ³	1960
specific heat	kJ/(kg*K)	1.02
Heat of reaction	kJ/kg	3.75E+02
Average Molecular Weight	g/mol	3.00E+03
Concentration of kerogen in shale	kg/m ³	3.30E+02
Time increments	hr	10

Results: One Dimensional Temperature Profile

The one dimensional temperature profile uses the equations described above as well as the values found in Table 2 to describe what the temperature variation in the reservoir will be at different distances from the heaters. The lowest temperature that kerogen begins to crack at a significant rate is 615°F. The optimum temperature for kerogen cracking is around 700°F. Until the center point reaches at least 615°F, hydrocarbons cannot be produced because the part of the reservoir that surrounds the production well still has no significant porosity and therefore does not allow flow of hydrocarbons out of the reservoir.²¹ Therefore, the optimum temperature for production to begin in the reservoir is 700°F at the center point of the heaters. The graph below

²¹ Feng H.Y., Pan Zhenglu, Smith, J. M. (1985). Rates of Pyrolysis of Colorado Oil Shale. *AiChE Journal*, 31, 721-728.

represents the increase in temperature seen at the midpoint of the two heaters that are sixty feet apart.

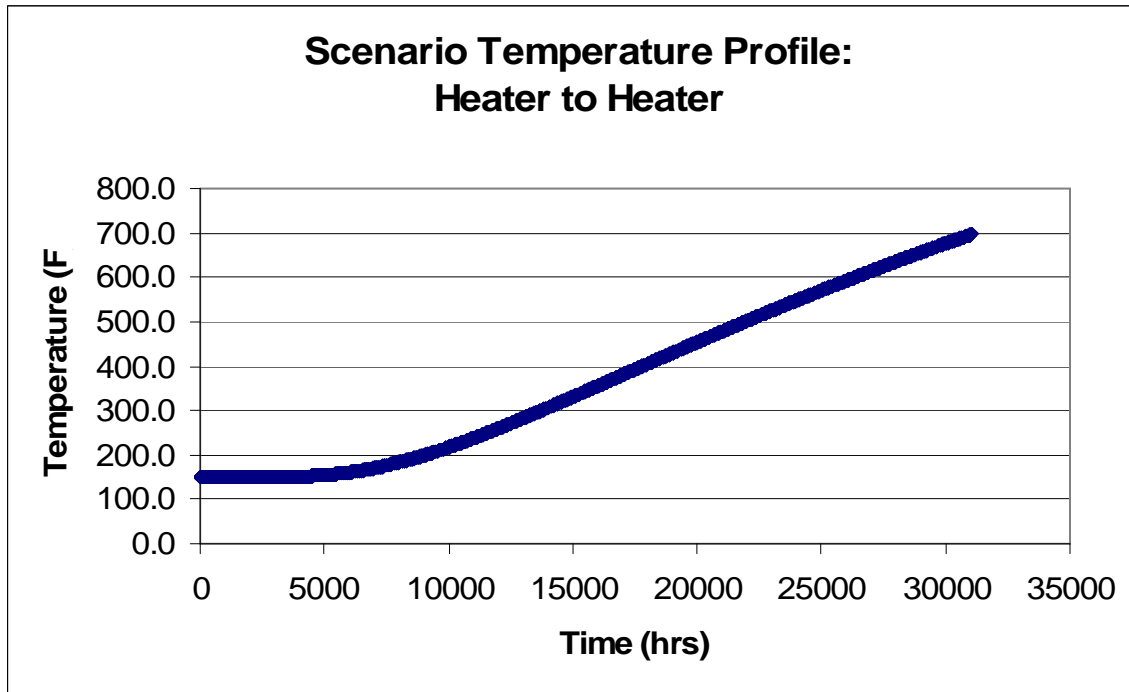


Figure 4: Temperature Profile for Midpoint of Reservoir. Represents the temperature change over time for the distance directly in between the two heaters that are spaced 60 feet apart.

Figure 4 displays the temperature of the reservoir staying constant for the first 5,000 hours at the original reservoir temperature of 150°F. It begins to increase steadily after this initial period. This increase in temperature is linear. One main reason that the increase is observed as being linear is because the same amount of heat is transferring towards the center of the reservoir from both sides. The heaters that are found thirty feet away from the midpoint of the reservoir are at 1500°F. These heaters begin transferring heat at the distances closest to them and move out slowly over time. As seen above, the temperature of the profile reaches 615°F at about 3.1 years. It takes the midpoint of the reservoir 3.6 years to reach 700°F.

Below, in Figure 5, is a graph of the midpoint between the heater and a freeze wall that is positioned sixty feet away from one another. Though this area will not have a production well, it is still possible to see how much time it will take for the center of the heater and freeze wall to reach 700°F to compare to the time that it takes between two heaters. The graph below displays that it takes about eleven years for the center of the area to reach the desired temperature.

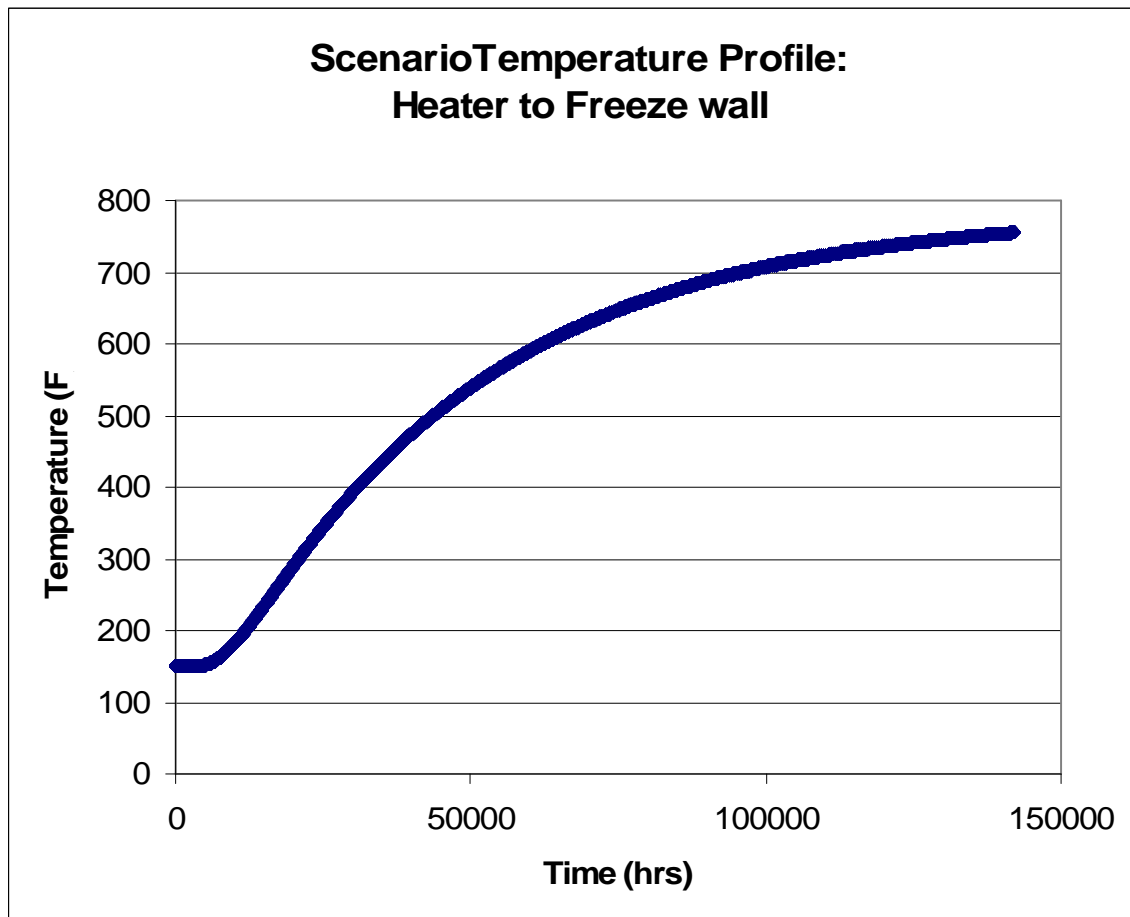


Figure 5: Temperature Profile for Heater to Freeze Wall. Displays the temperature change at the center of the reservoir between a heater and the freeze wall that are locating sixty feet apart.

The temperature change over the distance of the reservoir varies greatly throughout the heating process. Between the two heaters, the temperature can be described as a concave up parabola as seen in Figure 6. This is because the two end

points are heaters that are maintained at 1500°F. Because the heaters are maintained at these levels, the other temperatures throughout the reservoir are always increasing. If enough time passes, the parabolic lines would move closer and closer to becoming straight, meaning that the temperature would be constant across the reservoir.

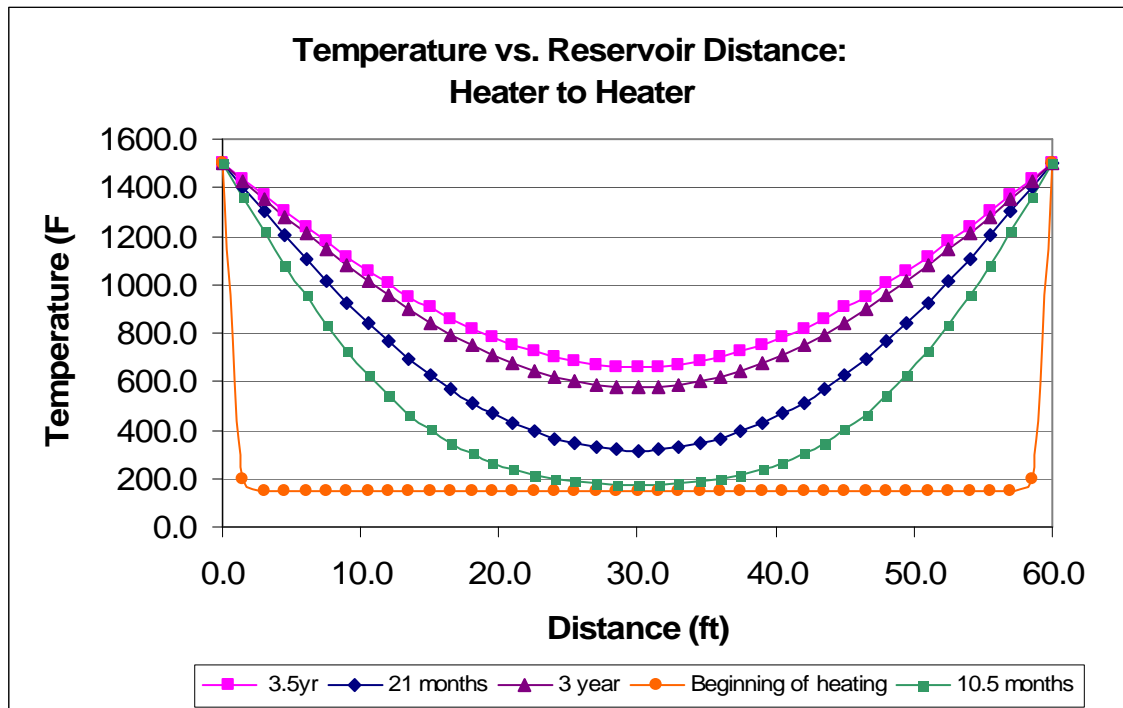


Figure 6: Temperature vs. Reservoir Distance. At various time periods during the heating process, the graph displays the temperatures across the distance of the reservoir. There is a heater at zero feet and sixty feet.

The shape of the temperature vs. reservoir distance for the heater to the freeze wall has a very different shape than the heater to heater graph. Because the freeze wall is at 32°F and the heater is set at a constant 1500°F, the curves generated are concave up but slope down toward a lower bound as seen in Figure 7. As time passes and more heat transfers across the reservoir, the temperatures at the different distances begin to move closer to the form of a line. When the temperature of the midpoint reaches 700°F, the temperature distribution is completely linear. This fact displays that the freeze wall is having a large affect on the temperatures in the reservoir. Because the freeze wall acts

like a heat sink, it takes more time for the midpoint to reach the necessary temperature and more heat is being lost in the process to the freeze wall.

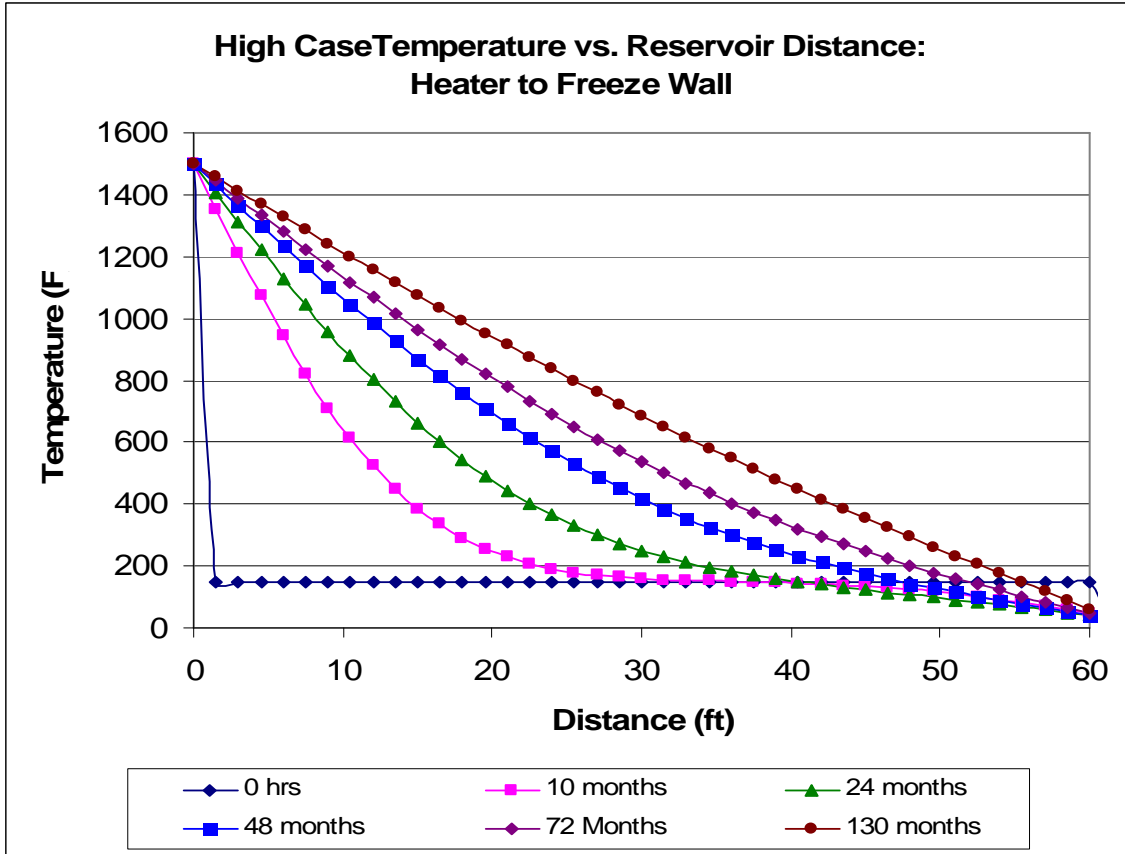


Figure 7: Temperature vs. Reservoir Distance between a Heater and the Freeze Wall. At various times during the heating process, the graph displays the temperatures across the distance of the reservoir. There is a heater at 0 feet and the freeze wall is at 60 feet.

Results: 1D Temperature Profile without Heat Generation

In the previous results, the heat generated from the cracking of the kerogen is considered. A large amount of the heat that is transferred throughout the reservoir is caused by the heaters. Because of this, it is of interest to determine how much heat is being added to the process by the cracking of kerogen. To observe the affects of the cracking on the overall temperature profile, the heat generation term will be deleted from

Equation 8. The results from this analysis will display how the heat from the reaction affects the temperature profiles displayed in the previous section from the initial analysis of the one dimensional temperature profiles.

With the deletion of heat generation term, the Temperature vs. Time profile changes very slightly. Figure 8 below displays the results for no heat generation. In comparison with Figure 6 above, this graph is very similar. As a matter of fact, it has a very small difference in the overall amount of time that it takes the center to reach 715°F. The time that it takes this model to reach the production temperature is slightly higher than that with the heat generation. It is found to be about 3.8 years. This is about a 5% difference from the original value found in the previous trials.

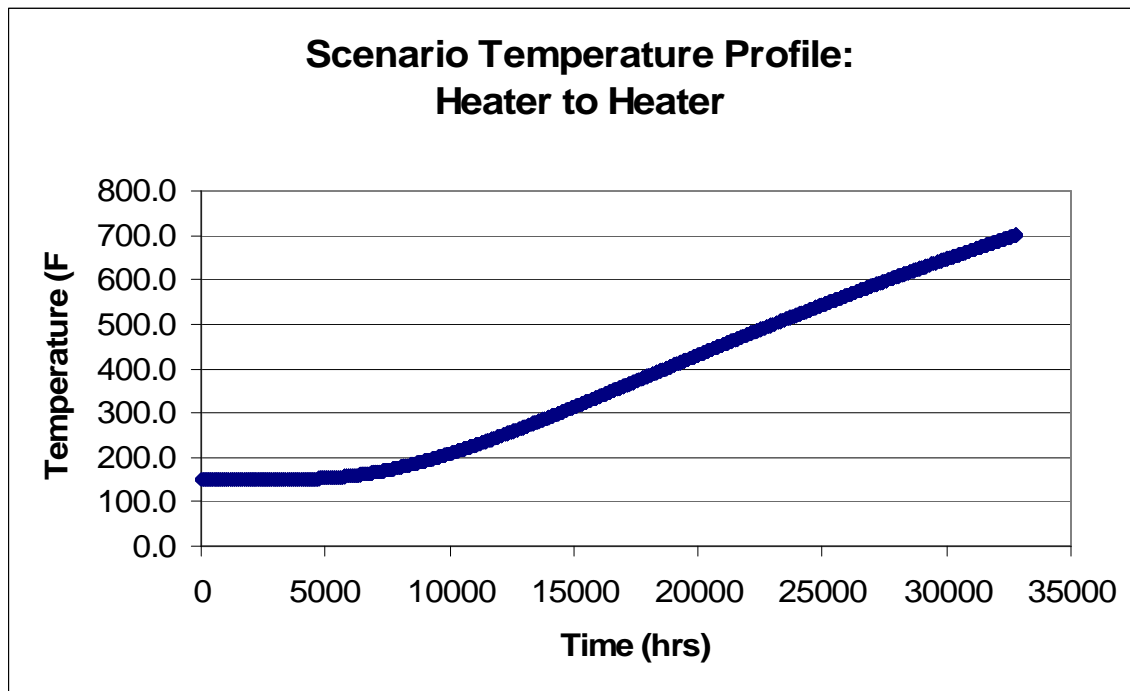


Figure 8: Temperature vs. Time excluding Heat Generation. Displays the temperature as it changes over time in the center of two heaters that are spaced sixty feet apart in the reservoir.

The Temperature vs. Reservoir Distance graphs can also be compared to see the difference between these two cases. Figure 9 below displays this particular graph without

the heat of reaction. It looks very similar to the graph that does have the heat of reaction included.

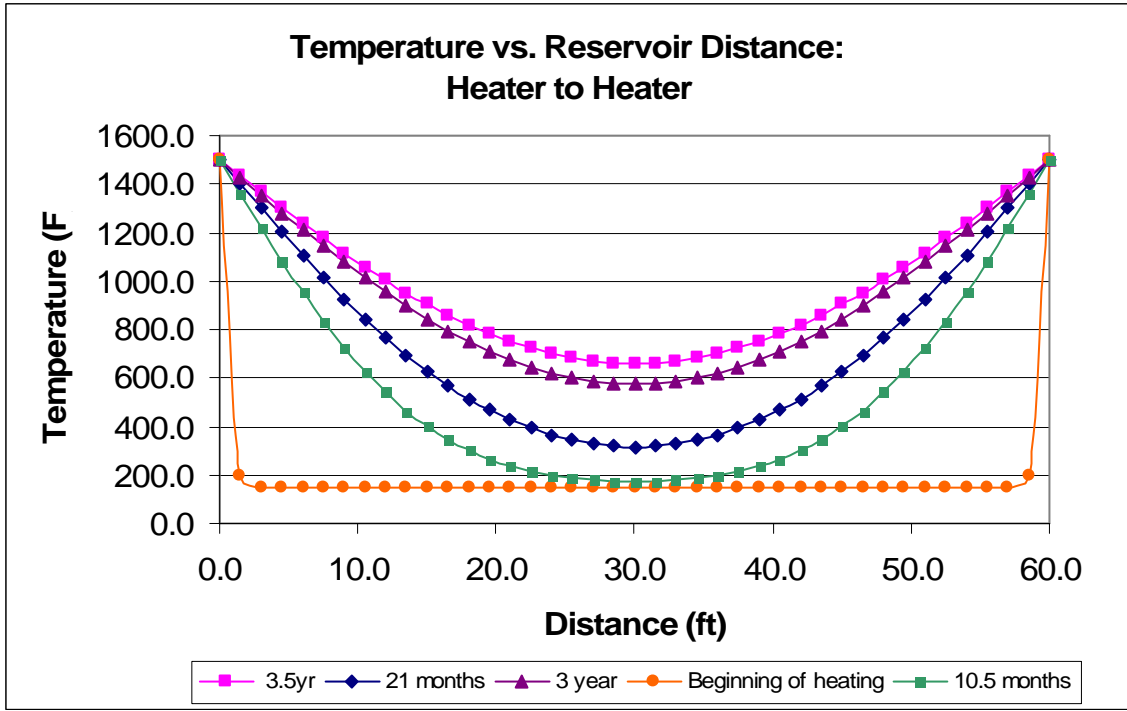


Figure 9: Temperature vs. Distance without Heat Generation. Displays how the temperature changes over time in the reservoir without heat being generated from the cracking reaction.

The very small difference found between the timing of the two different cases presented above displays that the heat given off by the heaters is much higher than that generated from the reaction. The difference between the times for each profile is so small, that it can be assumed that the heat of reaction term does not need to be included in the higher dimensional models that will be used to evaluate heat loss to surroundings. This time difference is also assumed to be even less important when the full hexagonal pattern of heaters is taken into consideration.

Results: 1D Temperature Profile affect of Thermal Diffusivity

The temperature profiles displayed above assumed a thermal diffusivity that is constant as well as one distance for well spacing. These two values were taken from laboratory research data as well as from the Rand report on Shell's in-situ conversion process. However, the question still arises as to what happens when the heater spacing is altered or the thermal diffusivity is found to be a different value than that found in the laboratory data. The one dimensional temperature profile can be used to run sensitivities on these two particular variables. Below is a graphical representation of the results from the sensitivities.

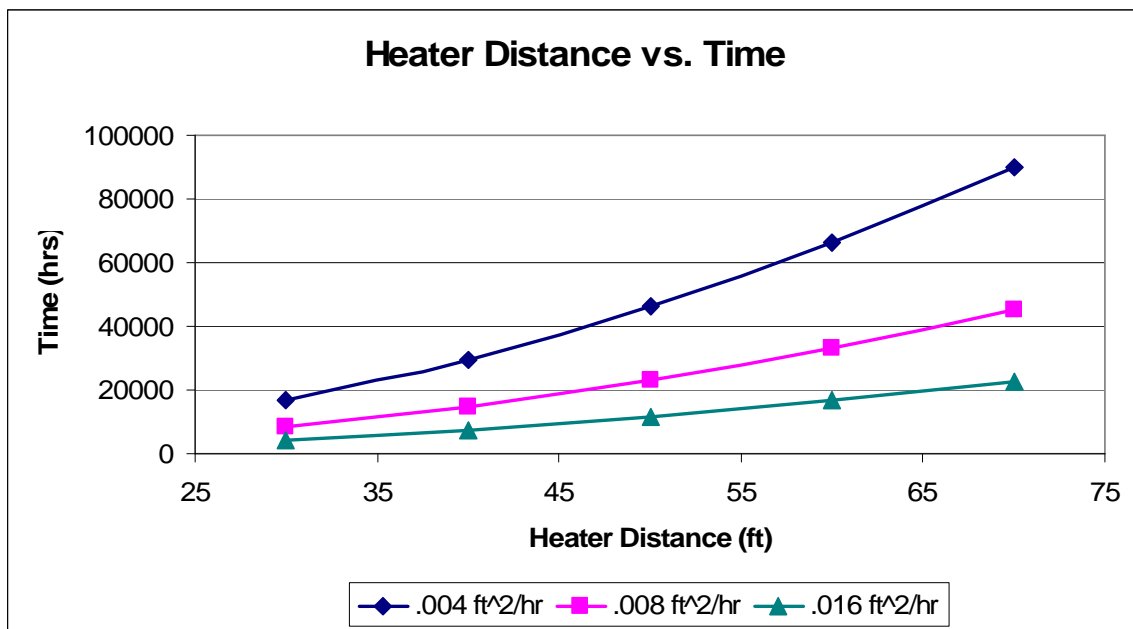


Figure 10: Heater Distance vs. Time. Displayed is the change in the amount of time it takes the center between two heaters to reach 700°F for different thermal diffusivities used for the reservoir source rock.

Figure 10 displays how the heater spacing and the thermal diffusivity affect the overall heating time for the center between heaters to reach a temperature of 700°F. The pink line represents the theoretical thermal diffusivity taken from experimental data. The blue line represents a thermal diffusivity of half the experimental data and the green line

represents that of twice the original amount. It can be seen that as the thermal diffusivity decreases, the amount of time to heat the reservoir to the proper temperature increases. It is also displayed that the farther the heaters are spaced, the more time it takes to heat the center point. This effect is more evident in the case with half the theoretical thermal diffusivity. The general trend is that as the diffusivity is decreased, the heater spacing will have more dramatic effects on the overall time it takes the reservoir to reach the desired 700°F. This affect can be illustrated by first looking at the curve that represents a thermal diffusivity of 0.016ft²/hr. When the heater spacing is changed from thirty feet to seventy feet, the total increase in time for the heating is observed to be 18410 hours. This is very small in comparison to the increase in time for the same spacing in the case where the thermal diffusivity is 0.004ft²/hr. This increase as seen in Figure 10 is 73660 hours. Because the heat does not transfer as easily through the reservoir when the thermal diffusivity is lower, the heater spacing has a significant affect on the time for heating.

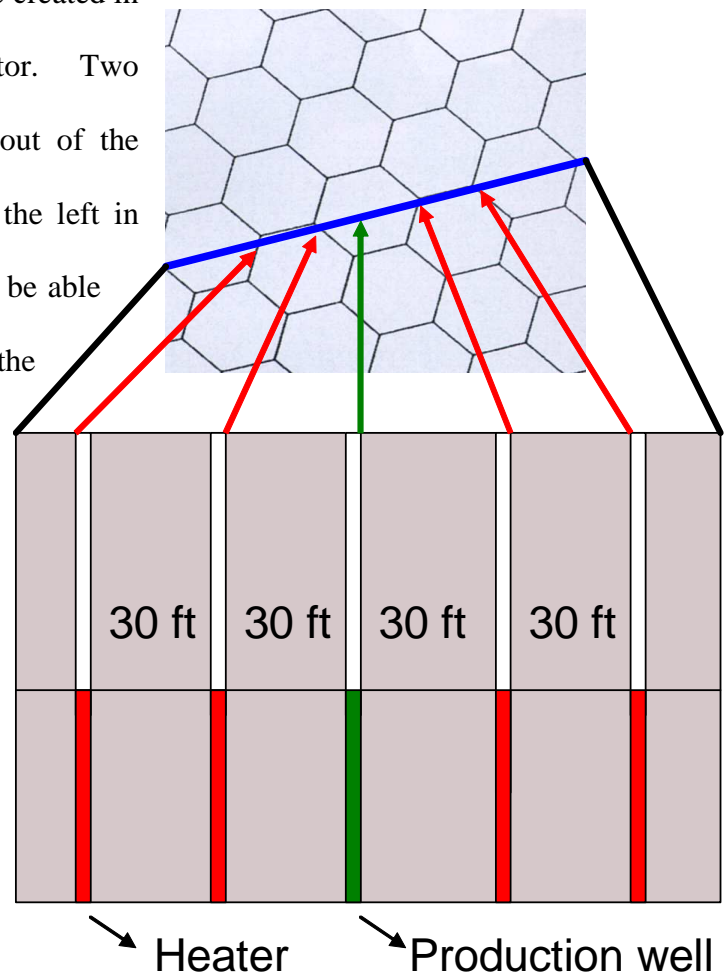
This analysis does display that though the thermal diffusivity can be kept constant in the reservoir, the actual thermal diffusivity value affects the heating process significantly. Because every production zone will inevitably have a different thermal diffusivity, the heating times and energy associated with this will have to be reviewed for each development.

Methods: Two Dimensional Profile

The one dimensional temperature profile is able to give an estimation of how long it will take to heat the reservoir area, but it is not able to account for the heat that is lost to the surrounding areas of the reservoir. These areas include the freeze wall and the

overburden of the reservoir that will be assumed to be initially at 150°F based on a geothermal gradient.²² The one dimensional profile also does not account for the full amount of heat that will be generated by all of the heaters in the hexagonal pattern. Because of this, there is a need to generate a two dimensional temperature profile that is able to account for the variables that were not addressed in the one dimensional model.

The two dimensional profiles were created in ANSYS which is a numerical simulator. Two different profiles were created. The layout of the first temperature profile is displayed to the left in Figure 11. This profile was generated to be able to view the amount of heat that is lost to the overburden by the heaters. The picture displays that the view in this profile is a vertical view that displays only the heater wells aligned by each other. Each well is found to be thirty or sixty feet away from each other depending on their location on the hexagonal cross section they were taken from.



The second two dimensional temperature profile that was generated displays what the temperature profile will look like in the center of a hexagon that has a complete set of heaters around it. This hexagon not only has the heaters that are directly contributing to the heat of that area, but also the

²² Well 272 on Geothermal map of Colorado (1982). Depth 1768m.

outlying heaters that are part of other hexagonal shapes in the pattern that are contributing heat. This temperature profile sets itself apart from the other profiles because it actually accounts for all of the heat being transferred into the area do to the hexagonal shapes. The picture displayed from this particular profile generated is a top view of the reservoir and the temperature profiles inside the hexagonal shapes.

These two temperature profiles were created using similar assumptions that were used to create the one dimensional temperature profiles. First, the thermal conductivity entered into the program was assumed to be constant throughout the reservoir area. Once again, because the rock consumes the majority of the reservoir, this assumption can be made. Also, because of the low amount of cells that can be processed in the ANSYS version used at the University of Oklahoma, the mesh was created with a two foot spacing. Finally, the freeze wall was kept at a constant 10°F and the heaters were kept at a constant 1500°F. These temperatures were kept to be consistent with the one dimensional temperature profile.

Results: Two Dimensional Temperature Profile without Heat

Generation

The first temperature profile generated in ANSYS was made to look at the flux into the overburden from the top of the heaters. This profile displayed that the heat that is lost to the overburden is a very insignificant amount compared to that be transferred into the reservoir. This can be explained by the lack of area that is actually directly in contact with the overburden compared to that in contact with the inner areas of the reservoir. The temperature above the heaters ranges from 175°F to 350°F. The video of the temperature profile created in ANSYS can be viewed by clicking on the area displayed below.

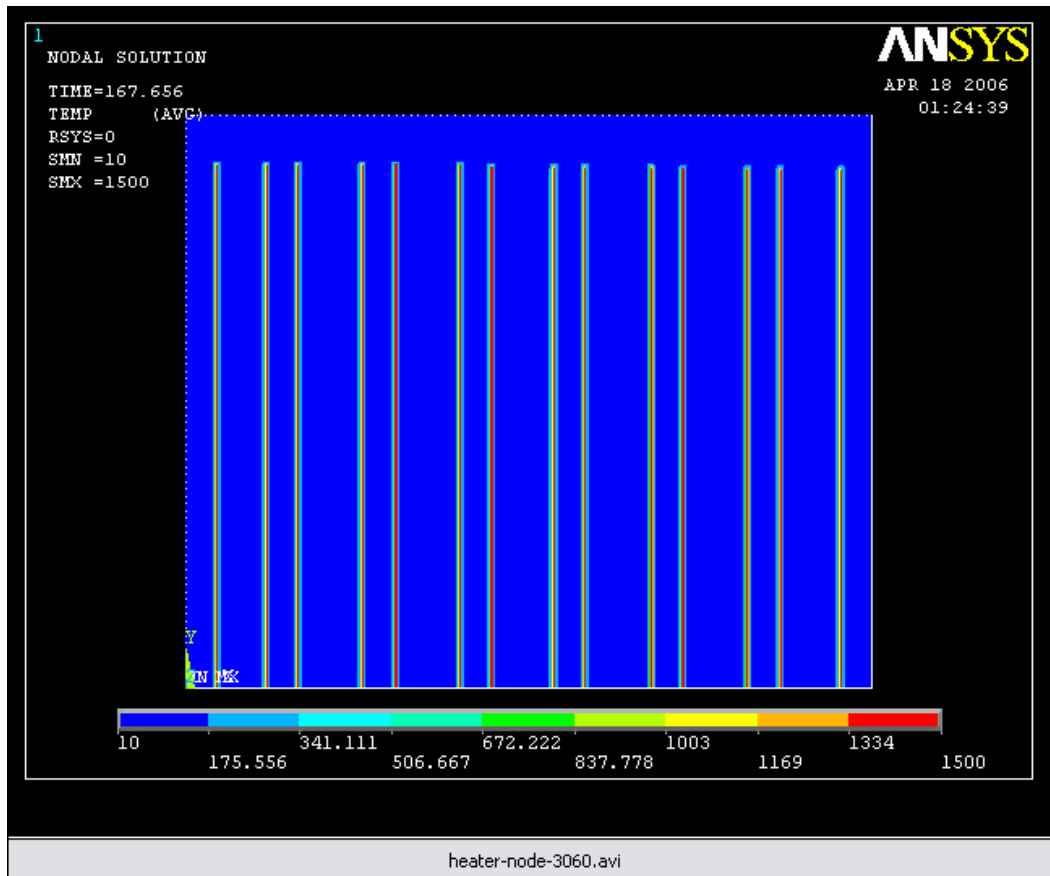


Figure 12: a 2-D temperature profile in the vertical and horizontal planes

At the end of the video, it is possible to see that in between the heaters that are thirty feet apart, the temperature rises to 1003°F to 1169°F. In the spaces where the heaters are sixty feet apart, the temperature only reaches between 341°F to 507°F. This area would generally be where a production well would be found. As explained earlier in the one dimensional profile, the target temperature for this area is 700°F. This profile displays that the temperature will not reach 700°F in the same amount of time that the one dimensional model does. The difference between these two models is the fact that the heat being lost to the overburden is being accounted for. Another item to mention is the fact that there will be additional heat added from the other heaters that are found in the hexagonal pattern.

The second two dimensional temperature profile was generated to display the heat that is added by all of the heaters that surround a single hexagon in the reservoir. In the temperature profile that can be viewed by clicking on the picture below, the center hexagon increases in temperature much faster than the outlying hexagons. The profile displays a quality that has not been displayed from the other temperature profiles created. Not only will two heaters be contributing to the temperature, but there will also be several other surrounding heaters generating heat for the temperature profile. With the other heaters accounted for, it takes the center of the hexagon about 2.7 years to reach a temperature of 700°F. This is approximately 23% faster than the time calculated from the one dimensional temperature profile.

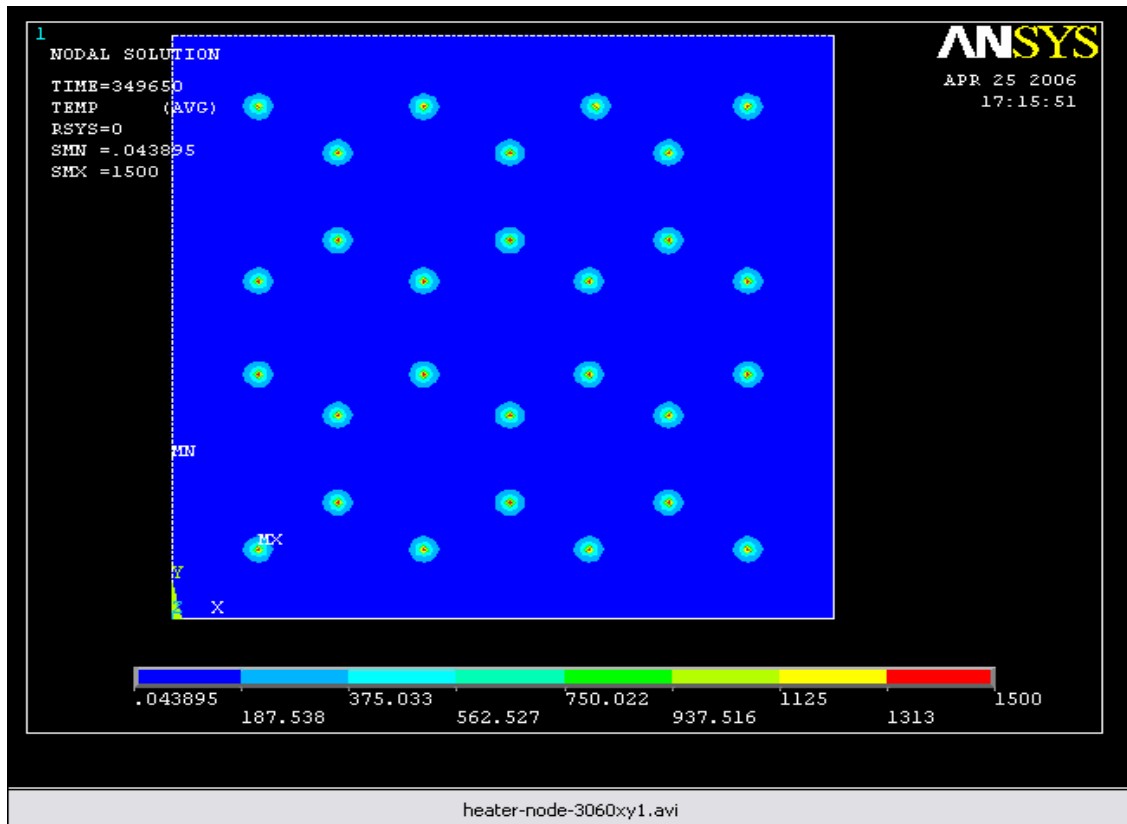


Figure 13: a 2-D temperature profile in the two horizontal planes

Composition Model

The kerogen that is found in the shale oil rock cracks into smaller hydrocarbons that are able to be produced. As displayed by the temperature profile, there is a large range of temperatures at different points in the reservoir. Because of these vastly different temperatures, different hydrocarbons will form and crack at different times. To know how to design the surface facilities, it is necessary to determine the composition of these hydrocarbons that will be exiting the reservoir.

The kerogen that is being heated and consequentially cracked can be modeled as a common cracking method in refineries called visbreaking. Visbreaking consists of taking heavy hydrocarbons with large viscosities and cracking them into smaller components so that they are more valuable. When the larger hydrocarbons crack into the smaller hydrocarbons; their viscosity naturally

decreases. This quality is what gives the process its name.

The model used for visbreaking was developed using laboratory data. The first step in using the model is to determine the kinetic data for the cracking processes happening within the system. Each component in the system can break down into $i-2$ components. Each component can also be formed by $i+2$ components. With this in mind, a kinetic constant must be found for every component that cracks into another component or forms from another component cracking. The first step in obtaining these

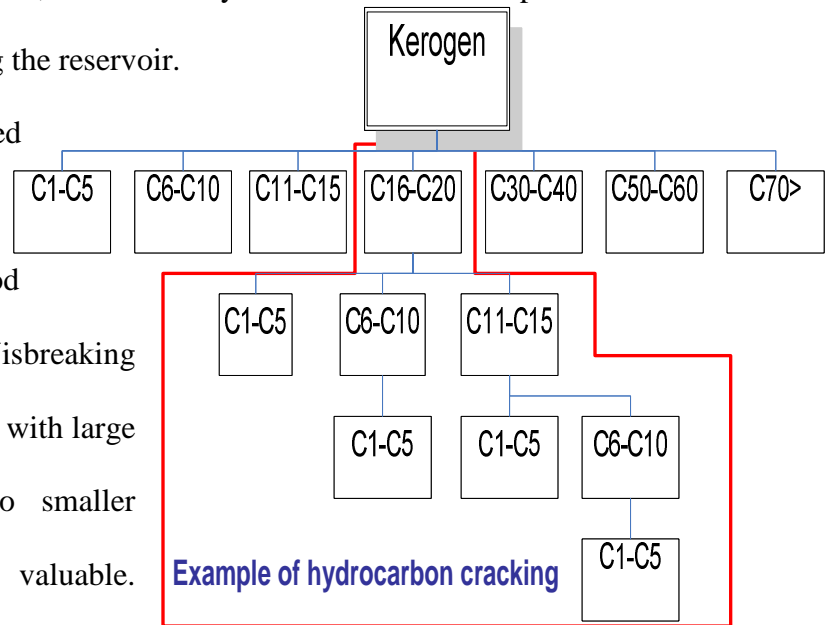


Figure 14: Visbreaking Cracking Example. Displays possible cracking for one product of kerogen cracking initially.

kinetic values includes calculating the pre-exponential factor as well as the activation energy for each component cracking into the next or vice versa. Equation 11 below gives the equation to find the pre-exponential factor according to the model.

$$A_{i,j} = (a_o + a_1 PM_i + a_2 (PM_i)^2) e^{\left[\frac{(PM_j - PM_i / a_4)}{a_3} \right]} \quad \text{eq. (11)}$$

Where: $A_{i,j}$ = Pre-exponential factor of i cracking into j

a_x = model fit parameters

PM = molecular weight of component

Once the pre-exponential factor is calculated, the activation energy can then be calculated using another set of fit parameters. Equation 12 below describes how to obtain the activation energy.

$$B_{i,j} = b_o + b_1 PM_i + b_2 PM_j \quad \text{eq. (12)}$$

Where: $B_{i,j}$ = Activation Energy of component i cracking into j

b_o = model fit parameter

PM = molecular weight of component

These kinetic values are found using a matrix in Excel. They are all calculated from the Arrhenius equation which is dependent on temperature. If the temperature of the system changes, the kinetic values will all change as well. The Arrhenius equation is displayed below²³.

$$K_{i,j} = A_{i,j} e^{\frac{-B_{i,j}}{RT}} \quad \text{eq. (13)}$$

²³ Castellanos, Jullian. "Visbreaking Design Considerations". Encyclopedia of Chemical Processing and Design. 1998

Where: $K_{i,j}$ = rate constant for component i cracking to j

$A_{i,j}$ = pre-exponential factor

$B_{i,j}$ = Activation Energy

R = Gas constant

T = Temperature

Once the matrices are developed for every temperature in a distribution, the kinetic values found within can then be used to calculate concentration changes of each component within the system. This calculation is done by using Equation 14 below. The equation adds the amount a component being formed and then subtracts the amount of the same component that is cracking into smaller components²⁴.

$$\frac{dC_{S_i}}{dt} = \sum_{k=i+2}^n K_{k,i} C_{S_k} - C_{S_i} \sum_{j=1}^{i-2} K_{i,j} \quad \text{eq. (14)}$$

Where: $\frac{dC_{S_i}}{dt}$ = Change in concentration of i over time

$K_{i,j}$ = kinetic constant for i cracking into j

As temperature changes throughout the reservoir, this equation can be evaluated at different points to get an estimate of what the concentration would be. The range of temperatures that the equation would be evaluated over is 700°F to 1450°F. This large range of temperatures causes a large amount of average kinetic values to be used decreasing the accuracy of the model.

²⁴Castellanos, Jullian. "Visbreaking Design Considerations". Encyclopedia of Chemical Processing and Design. 1998

Results: Composition Model

The visbreaking model uses laboratory fit parameters to calculate the kinetic values for each cracking reaction. These parameters were determined using a heavy hydrocarbon mixture. The parameters used in the analysis can be found in table 3 below.

Table 3: Laboratory Fit Parameters for Determining Arrhenius Equation Values.

a₀	1.51E+12
a₁	1.90E+08
a₂	2.06E+06
a₃	146.95
a₄	11.35
b₀	42894.00
b₁	-4.50
b₂	3.00

The temperature profiles developed from the previous section were used to provide information on the time and temperature that different parts of the reservoir are at at different times. This data was used to evaluate the composition model. Because of the large amount of kinetic constants used in this model, average temperature ranges as well as average hydrocarbon ranges had to be used. Using these averaged kinetic values, the composition model displayed a trend of results as displayed below in Figure 15. At 700°F, it is displayed that there is a fairly large distribution of hydrocarbons. This distribution of hydrocarbons is expected. However, it would also be expected that there would be some amount of heavier hydrocarbons left in the reservoir at this point in time. It is not feasible that all of the heavy hydrocarbons would have cracked at this point in the heating process. At 800°F, there is a lower distribution of hydrocarbons in the reservoir. The model gives results that the only hydrocarbons left in the reservoir are the

light hydrocarbon gases as well as the light end oils. There is no significant amount of any other component groups left in the reservoir. Finally, once the reservoir reaches 900°F, the only components that are left in the reservoir are methane and ethane. Though there may be a high amount of light ends, it is not possible that the entire reservoir has cracked into only these two components in the amount of time displayed. Therefore, it is determined that the visbreaking model does provide a general trend for the composition of the reservoir, but it cannot be used in finding the actual compositions of the reservoir. A model that would more accurately describe the process of kerogen cracking that is occurring under the earth would be the best model to use in this particular case and would give a better result.

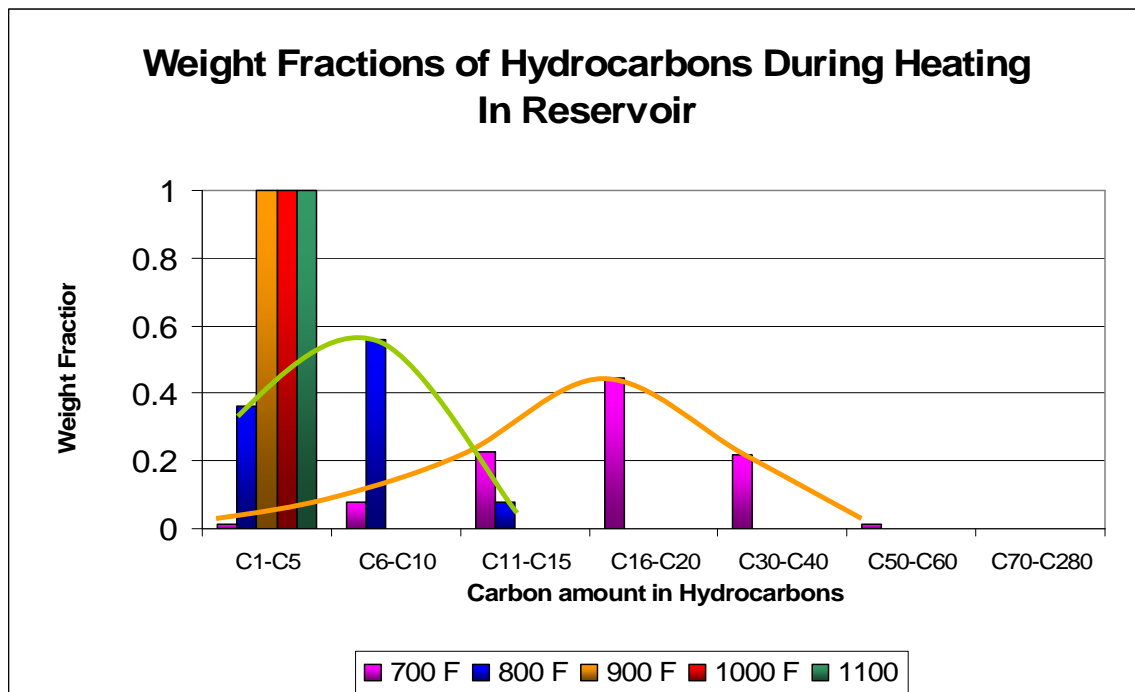


Figure 15: Composition Distribution for Continuous Heating Reservoir. Each bar color describes a different temperature. As the cracking continues, more light end hydrocarbons form as expected.

The values used to calculate the weight percent above can be used to calculate the average composition of the reservoir. If these results for the model were accurate to

those of the actual reservoir, this overall composition would be useful in determining the sizes for the processing facility. As expected, the composition of the reservoir is dominated by the ethane and methane. The weight fraction of ethane is 0.65 and that of methane is 0.35. The other hydrocarbons have no significant presence in the reservoir.

There is a complex mathematical model that has been developed by Burnham and Braun that can model the decomposition of kerogen into other hydrocarbon components. It is suggested that this model be used to determine an accurate estimation of what the composition of the reservoir maybe during the heating process.

Surface Facilities

Oil Processing

Once the kerogen in the reservoir has been heating for two and a half to three and a half years, as found from the temperature profiles, production can begin.²⁵ At this point in the heating process, the kerogen has cracked into several light hydrocarbons including gases and oils. The average production temperature of this fluid mixture is assumed to be around 700°F and at a pressure of 1000psi.

Because shale oil has never been produced on a large scale using a complete in-situ method of conversion, the composition of the product is unknown. However, Shell has released a report stating that the product from their experimental in-situ production site is approximately 1/3 natural gas and 2/3 light sweet crude oil on a heating

²⁵ Bartis, James T. Oil Shale Development in the United States: Prospects and Policy Issues. Rand Corporation: Santa Monica, 2005. pg 17.

basis.²⁵ This overall composition has been assumed for the calculations and simulations dealing with the oil and gas processing facilities on site.

Compositional issues that concern the design of surface facilities include sulfur content, producing non-hydrocarbon gases, and producing solid carbon. The average molecular weight of kerogen, the material that will be cracked, is $C_{200}H_{300}SN_5O_{11}$.²⁶ This chemical formula displays that there is very little sulfur associated with the large hydrocarbon molecules. Because of this average molecular formula and because Shell's experimental oil displaying very low amounts of sulfur, it is assumed that the surface facilities model will not need to include a sulfur processing unit. The molecular formula of kerogen shows that there is a small amount of nitrogen and oxygen associated with the compound. Because of such a small amount, it is assumed that there is no need for facilities to separate these gases as well. With the cracking of the kerogen, there will most likely be carbon solid that is formed in the pores of the reservoir rock. It is assumed that there will only be a trace amount of this carbon and there will be no production of it through the wells. This is based on the fact that there will be extra hydrogen from the cracking reaction that will bond with the carbon solid and therefore not allow much residual carbon solid.

Water is generally an issue with surface facilities because of the treatment necessary to place it back into the reservoir or to dispose of it. In the in-situ method of production of shale oil, the water is initially removed from inside the boundaries of the freeze wall before the heaters are turned on so that it is not contaminated. Once the oil production has stopped, the water is then pumped back into the reservoir. However, the

²⁶ Pan, Zhenglu, H.Y Feng and J. M. Smith. "Rates of Pyrolysis of Colorado Oil Shale." AICHE Journal 31.5 (1985): 721-728.

reservoir is at a very high temperature and pressure. The water that is being replaced immediately flashes when it is exposed to the temperature of the reservoir. This vapor comes back to the surface along with several residual light end hydrocarbons. The water is then treated on the surface, to separate the hydrocarbons from the water, and is pumped back into the well. This process continues, at the end of the production of the well, until the water flashing from the well comes back with very trace amounts or no amount of hydrocarbons.²⁷

²⁷ Seebach, Linda. (2005). Seebach: Shell's ingenious approach to oil shale is pretty slick. Retrieved 2/17/05 from Rockymountainnews.com.
http://www.rockymountainnews.com/drmn/news_columnists/article/0,1299,DRMN_86_4051709,00.html

The surface facilities that operate to strip the water of the hydrocarbons require a heat exchanger, a flash column, a valve, and a pump which can be seen below in the flow sheet. Because the temperature of the water and hydrocarbon mixture is coming to the surface facilities at 680°F, it is necessary to cool the mixture before it is separated. The mixture processes through an expander to recover some energy and then through a heat exchanger to ultimately decrease the temperature between the boiling point of water and the gaseous mixture in the water. Once this task is accomplished, the mixture is sent into a flash column that is able to separate the hydrocarbons from the water. The water exits from the bottom of the flash column. It is then cycled back through the heat exchanger to lower the temperature of the incoming mixture before it is sent into a pump which cycles it back into the well. The hydrocarbons are passed through a valve that leads to a mixer in the oil processing facility. The final step of this hydrocarbon mixture is to pass through

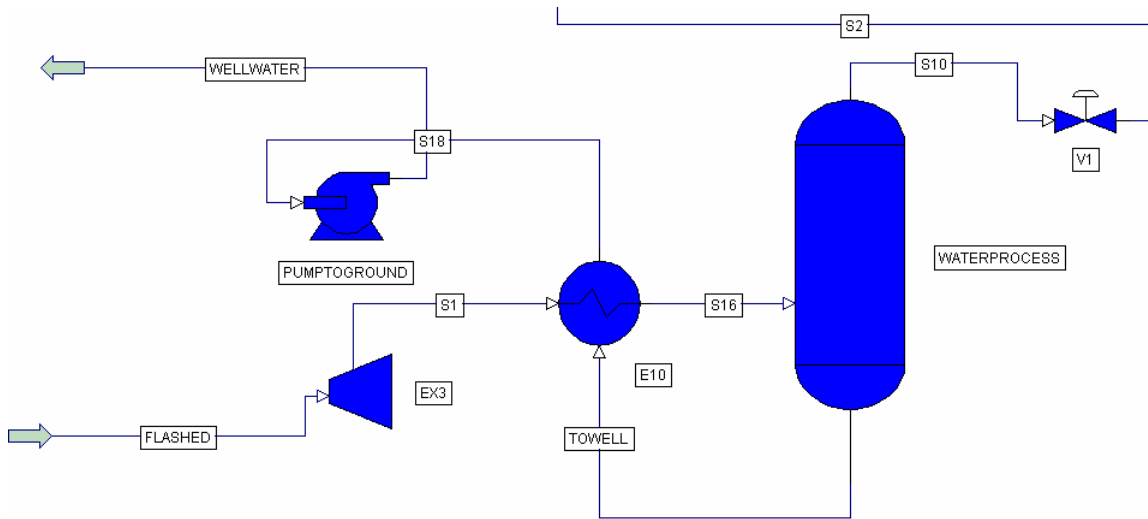


Figure 16: Water Processing Flow Sheet. Represents the water processing plant for the surface facilities. Will process water a fourth of the time that the oil is processing.

a distillation column for separation. The water processing facility will only be operating a fourth of the time that the oil processing facility operates.

The hydrocarbon mixture that enters into the oil and gas processing facility is entering at a high temperature and pressure. The flow sheet that this fluid passes through is displayed in Figure 17 below. The fluid first passes through an expander to recover

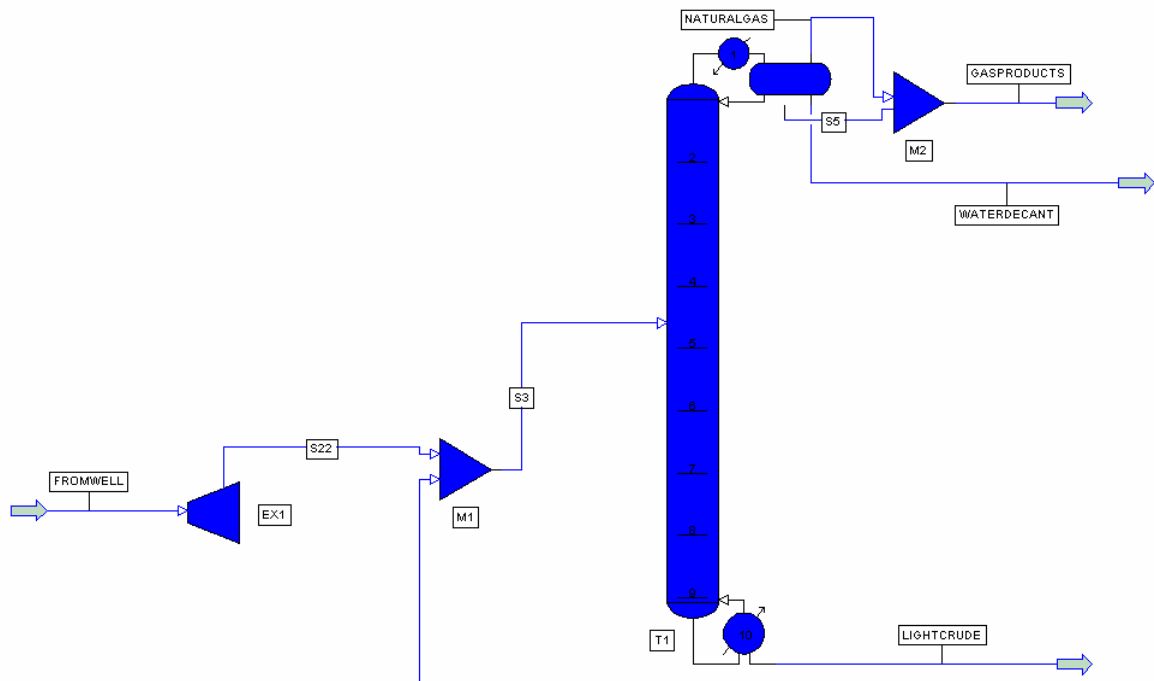


Figure 17: Oil Processing Facilities. Flow sheet created in PRO II for the oil processing skeleton plant for the shale oil surface processing facility.

energy from the high pressure. It is then sent into a mixer that mixes the hydrocarbon product coming from the water processing facility. This mixed product is sent into the distillation column where it is separated. The distillation column is able to separate methane through pentane from all of the heavier hydrocarbons. The heavier hydrocarbons exit the bottom of the ten tray distillation column and are sent to market. The lighter gases are extracted from the top of the distillation column. Once these products exit the top of the column, there are several options that can be reviewed for further processing and/or sales.

Results: Surface Facilities

The processing facilities for the full scale production are designed to be able to produce 80,000bpd which includes the gas that makes up one third of the heating composition of the hydrocarbons. By constructing the plant to process 80,000 barrels of oil per day, it is possible to produce twenty acres of land at one time. Pro/II is used to model these surface facilities and give initial estimations on the costs of equipment and utilities.

The first step in making the Pro/II model is finding the true boiling point data for a light sweet crude oil. This data is entered into Pro/II to allow the modeling of the hydrocarbons that are coming out of the reservoir. Table 4 below displays the TBP data used to make the pseudo properties in Pro/II.²⁸

²⁸ Bagajewicz, Miguel and Shuncheng Ji. "Rigorous Procedure for the Design of Conventional Atmospheric Crude Fractionation Units. Part 1: Targeting." Industrial and Engineering Chemical Research 40.2 (2001): 621.

Table 4: TBP data and Lightend Composition Data. True boiling point data for a light sweet crude oil sample that is used by Pro/II to generate pseudo components.

Vol %	Light Crude	Compound	Volume %
5	45	Ethane	0.6
10	82	Propane	0.9
30	186	Isobutane	0.39
50	281	n-butane	1.26
70	382	isopentane	0.95
90	552	n-pentane	0.9

Pro/II generated the graph below by using the above true boiling point data. The true boiling point data was modified to be able to account for the fact that products with a boiling point greater than 850°F would most likely not be produced. This assumption was made based on the idea that these heavier components would have already cracked into smaller components or would be too large to be able to move out of the reservoir.

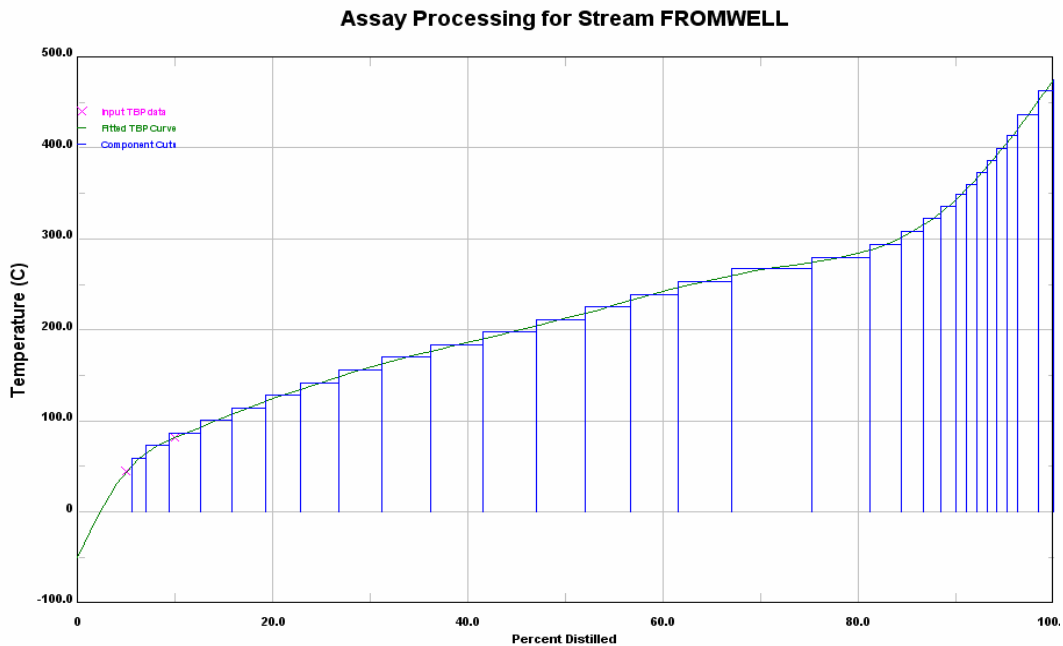


Figure 18: TBP diagram for the hydrocarbons being produced from cracking kerogen reservoirs.

The distillation column in Figure 17 is made to separate methane through pentane from the heavier hydrocarbons. The separation point is between pentane and the oil

pseudo component NBP 119 that has been generated by Pro II. As displayed in Figure 19 below, the boiling point difference between these two products is about 50°F.

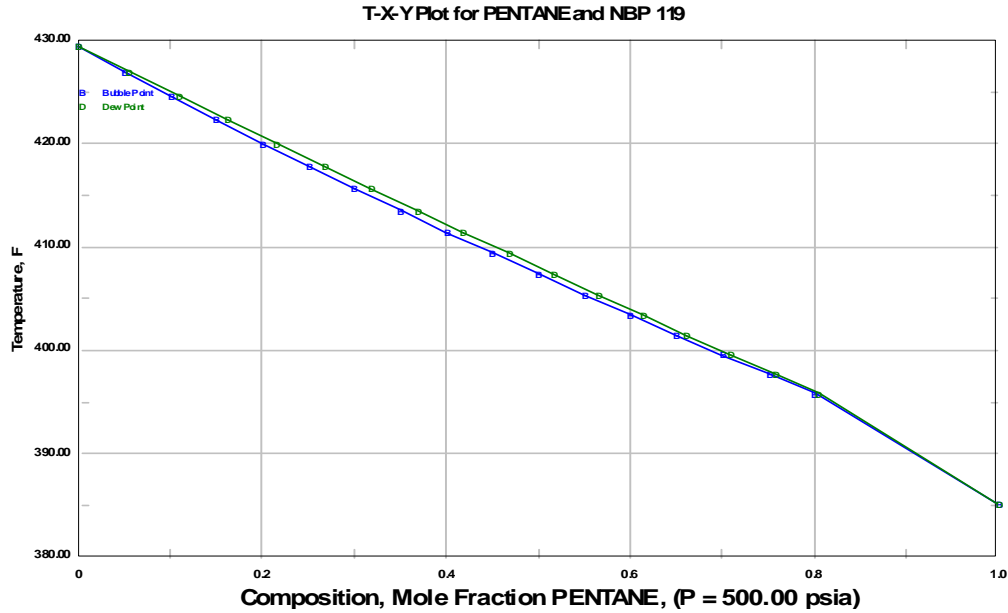


Figure 19: T-X-Y Plot for Separation Point in Distillation Column. Displays the two components that represent the separation point in the column.

The goal of the separation process is to get the lowest amount of methane through pentane in the heavy oil stream that exits the bottom of the distillation column. This stream will be sent to Denver for sales and a large amount of gas in the stream could cause two phase flow, therefore, the separation must take place. The methane through pentane components exit the top of the column once they have been separated. The compositions of these two streams can be viewed below in the Table 5. The data in the table displays that the composition of the gas products stream is mostly methane. The other gases do have a significant amount represented as well, but not as much as methane. The table also displays that the crude products stream is composed of very little gas. Pentane has the highest mole percent present in the crude oil stream of all of the

gases in the mixture. Because there is such a small amount of gas left in the crude oil stream, there will not be any problems related to two phase flow in the pipeline to market.

Table 5: Compositions of light ends in the two streams leaving the distillation column. Light crude is the bottoms product while natural gas is the top product.

Streams	Compositions (Mole Fractions)						
	Methane	Ethane	Propane	I-Butane	Butane	I-Pentane	Pentane
Gas Products	0.822	0.005	0.037	0.015	0.045	0.023	0.018
Crude Oil	0.002	0	0.001	0.001	0.004	0.008	0.009

The actual distillation column is constructed with ten trays including the condenser and the reboiler. The column condenser is operated at a constant 60°F while the reboiler operates at a temperature of about 790°F. These temperatures allow the gases to move to the top of the column and the liquids with higher boiling points to exit the bottom of the column. A summary of the tray temperatures are displayed in Table 6.

Table 6: Tray Temperature Summary.

Tray Number	Temperature (°F)
1-condensor	60
2	323.4
3	410.3
4	480.6
5	571.8
6	626.4
7	669.9
8	710.2
9	750.7
10-Reboiler	787.9

The pressure is held constant throughout the column. There is no pressure change considered across the trays though there would be a slight pressure drop in reality. The trays in the column are designated as sieve trays. The sieve trays are the most cost effective tray option and will perform the necessary separation. The entire column is made of carbon steel because there will be no hydrogen flowing through it. Finally,

based on the flow rate of the fluids entering the column and tray spacing, Pro II was able to determine the size of the column and trays. This sizing was then used in calculations for costs.

Because there is a large amount of energy needed to produce the oil and gases from shale oil, it is always favorable to be able to recover some of the energy generated for production. For this reason, expanders were placed at both the entrances of the water processing and oil processing facilities as displayed in Figures 16 and 17 above. The expander found at the entrance to the oil processing facility operates at 2592 hp. This means that the expander is able to recover 1933kW of energy from the producing fluid. The second expander is found at the beginning of water processing facility. This expander operates at about 9000hp which is equivalent to 6174 kW. This energy can then be used to run the pumps that feed water back into the wells or it can be used for other operations in the process of extraction. Overall, this is a small amount of the total energy that is produced to operate the project, but it is still significant enough to justify the expense of the expanders.

The flash column in the water processing facility is used to separate the residual hydrocarbons from the reservoir from the water that is being cycled in and out of the reservoir. This flash column operates at a constant temperature and pressure. The pressure that the flash column is operated at has to be the same or above the pressure that the mixer in the oil processing facility is operating. If this pressure is lower than that in the mixer, the hydrocarbons will not be able to enter into the oil processing facility. The temperature that the flash column operates at has to be in between the boiling point of the hydrocarbon gases and the water. This allows the two different substances to separate

with a simple flash and also decrease the duty of the flash column. Below is a summary of the operating conditions for the flash column used for the separation.

Table 7: Operating Condition of Flash Column.

Operating Condition	Value
Pressure	500 psi
Duty	-18.5 mmbtu/hr
Temperature	134.64 °F
Pressure Drop	0 psi

The overall flow sheet for the separation process is fairly simple but can become very complex with further analysis of products produced from the reservoir. With an accurate composition of sulfur, hydrogen, and oxygen production, there may or may not be added features to the skeleton flow sheet, displayed below in Figure 20.

Once the oil and gas products have been processed, they must be sent to market. There are several options for the future of the products coming from the production of shale oil. These options include building a refinery on site or shipping the products to a refinery that is pre existing. The gas that is produced from the top of the column must be separated so that the methane can be used to generate power for the power plant. The ethane that is produced can be used for power generation as well or else it can be used to make ethylene on site. The propane through pentane are products that can be separated and sent to a refinery with the oil products as liquefied petroleum products. All of these options depend on a decision to build a refinery on site or not. To ultimately obtain the answer to this question, a detailed economic and risk analysis must be performed.

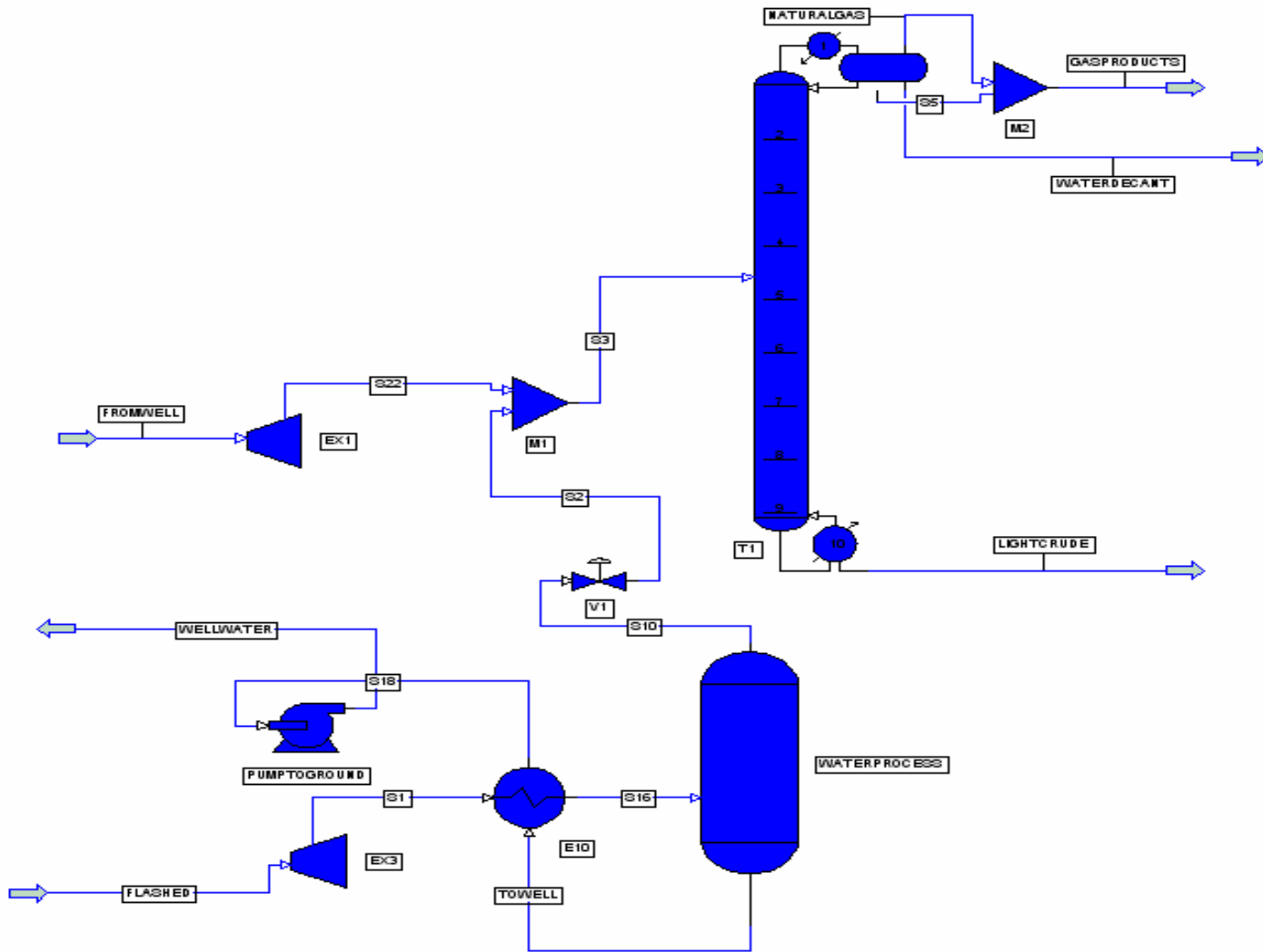


Figure 20: Complete Process Flow Sheet.

Pipelines

The pipeline network consists of all pipelines necessary to move produced oil and gas from the ground to their final destination with an estimated cost of \$51.37 million. The network of pipes begins at the wellhead. Eight pipelines from each acre, one per producing well, will connect to a header where the pipelines will converge to one. This will occur for all 20 acres that are producing at any given time. The pipeline from each acre will deliver the crude oil and natural gas to the main gathering pipeline. This pipeline is capable of carrying the full load of oil and gas produced by 20 acres, and delivers the product to the processing facility. The processing facility separates the oil and gas, where gas will be sent to the power plant and oil will be sent to a refinery.

Pipe Design

The size of the pipes used was estimated using one of two methods. Pipelines delivering oil and gas to the processing facility were estimated based on the optimum pipe diameter equation²⁹, $D_{i,opt} = 0.363q_f^{0.45} \rho^{0.13} \mu_c^{0.025}$, where q_f is the volumetric flow rate, ρ is the density, and μ is the viscosity of the fluid. However, variations in flow due to pumps and compressors on the oil and gas pipelines leaving the processing facility make the optimum pipe diameter equation inaccurate. For these cases PRO/II simulations are necessary using the *Line Sizing* calculation. PRO/II is used not only for sizing the pipe but also for sizing and simulating necessary pumps and compressors. In addition, PRO/II was used for determining the volumetric flow rate, density, and viscosity of the fluid in the gathering pipes.

²⁹ Peters, Max S., Timmerhaus, Klaus D., West, Ronald E., (2003). Plant Design and Economics for Chemical Engineers. P. 404. New York. McGraw-Hill.

All gathering pipelines are carrying an oil and gas vapor mixture that is estimated at 680°F and 1000 PSI. Based on these conditions, the volumetric flow rate, density, and viscosity are calculated. The pipeline from the wellhead to header was calculated to be a 4-inch, schedule 80 carbon steel pipe. Based on estimations of eight pipelines per acre and 40 acres of production, the length of pipe needed is approximately 400,000 feet. The pipeline from one acre, carrying fluid delivered from the eight producing wells per acre, is estimated as a schedule 80, 8-inch diameter carbon steel pipe with a total of 100,000 feet of pipe needed. The main gathering pipeline is a 20-inch, schedule 80 carbon steel pipe. Due to its large size and corresponding costs, it will be the shortest of all gathering pipes.

The distance between the production site and the Denver refinery is estimated at 225 miles with an elevation change of 1000 feet. Based on a PRO/II simulation, the diameter of the pipe must be 24 inches with a schedule of 80. Due to the length of the pipe it is necessary to include two pumping stations that split the pipe into three 75 mile long sections. The first pump has a pressure gain of 24 PSI and work of 30 kilowatts³⁰. The second pump, located 150 miles from the production facility, has a pressure gain of 54 PSI and work of 68 kilowatts³¹. The pumps were designed so that the fluid in the pipe remained liquid at varying temperatures and pressures. This is necessary due to safety concerns with LPG.

The product pipelines consist of everything leaving the processing facility: crude oil, natural gas, and LPG. The natural gas will be sent to the nearby combined-cycle

³⁰ Peters, Max S., Timmerhaus, Klaus D., West, Ronald E., (2003). Plant Design and Economics for Chemical Engineers. P. 519. New York. McGraw-Hill.

³¹ Peters, Max S., Timmerhaus, Klaus D., West, Ronald E., (2003). Plant Design and Economics for Chemical Engineers. P. 519. New York. McGraw-Hill.

power plant for energy production for the field and all leftover gas will be sold. The crude oil and LPG will be sent to the Suncor Refinery in Denver. The power plant will require 140 million cubic feet per day (MMcf/d). Approximately 75 MMcf/d of natural gas will remain. The pipeline to the power plant will be 10 inches in diameter and schedule 80, carbon steel pipe. It is expected that the power plant will be located approximately 2 miles from the processing facility. The gas that will be sold will be sent to Denver in a pipeline placed along side the crude oil and LPG pipeline. It is necessary to include a 5800 kW, centrifugal-rotary compressor on the 8-inch schedule 80, carbon steel pipe³².

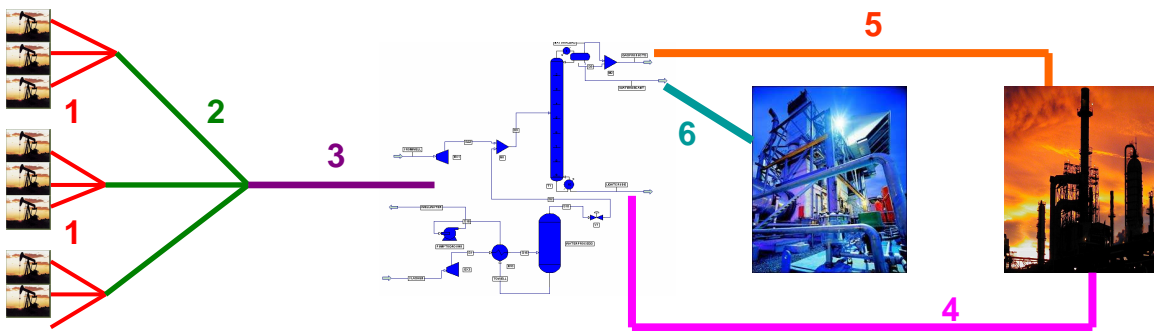


Figure 21: a diagram of how the pipelines will be laid out

³² Peters, Max S., Timmerhaus, Klaus D., West, Ronald E., (2003). Plant Design and Economics for Chemical Engineers. P. 531. New York. Mcgraw-Hill.

Pipe Costs

Pipe costs are estimated at almost \$174 million. The overwhelming majority of the costs are attributed to the 225 mile long crude oil/LPG pipeline and complementing natural gas pipeline. All pipe costs were estimated based on schedule 80, carbon steel pipe with welded construction. Therefore, the price variance is due completely to the diameter. The price per foot can be seen in the Table 8. The total price reflects the pipe necessary for the life of the project.

Table 8: Pipe Size & Cost Estimations³³

Pipe Description	Contents	D (in)	Schedule	Length (ft)	\$/foot	Total Cost
1. From Well	Oil & Gas	4	80	400000	\$ 10	\$ 4,000,000
2. From 1 Acre	Oil & Gas	8	80	100000	\$ 30	\$ 3,000,000
3. From 10 Acres	Oil & Gas	20	80	1000	\$ 100	\$ 100,000
4. Crude Oil to Sell	Oil	24	80	1188000	\$ 110	\$ 130,680,000
5. Gas to sell	Gas	8	80	1188000	\$ 30	\$ 35,640,000
6. Gas to Power Plant	Gas	10	80	10500	\$ 40	\$ 420,000

Power Supply

It is necessary to generate approximately 800 megawatts (MW) of power to supply the field with enough energy for production. The power needed is outlined with the equipment costs for most of the equipment. The majority of the power will be consumed by the heaters, over 700 MW. In addition, a buffer of approximately 100 MW has been added. This allows for such things as expansion, unforeseen power needs, or increases in production.

Due to a lack of infrastructure in the area, along with an already stressed Colorado power grid, it is necessary to build a new power plant. Current estimations show the cost

³³ Peters, Max S., Timmerhaus, Klaus D., West, Ronald E., (2003). Plant Design and Economics for Chemical Engineers. P. 503. New York. Mcgraw-Hill.

of a power plant of almost \$7 billion over the 25 year life of the project. This price includes natural gas used as fuel in the power plant that could have been sold. Although the costs are large, it will save between \$3 to \$8 billion dollars, depending on the price of electricity per kilowatt-hour, over 25 years. The purchase of electricity is only economical at prices less than \$0.03 per kilowatt-hour.

Power Plant

There are several options for the power plant. Nuclear, gas, and coal plants were all investigated. It is felt that a gas power plant is the best option for the current situation. Nuclear power plants are extremely expensive to build and have a bad public image. If a coal plant was chosen the coal would have to be shipped in from Wyoming. The efficiency of a combined cycle gas turbine power plant is almost double that of a gas turbine alone, with lower operating costs per megawatt-hour, and only slightly larger capital costs per megawatt³⁴. A combined cycle power plant combines a gas turbine and steam turbine, with the burning of

natural gas as a single heat source. The burning of natural gas turns the gas turbine. The exhaust from the gas turbine heats the water to steam, which enters the steam turbine. Combined-cycle power plants are a viable energy source for high power

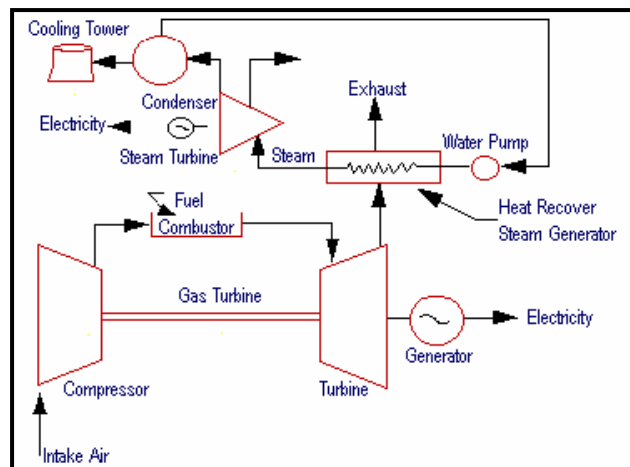


Figure 22: Combined-Cycle Power Plant Flow sheet
(www.cogeneration.net)

³⁴ Kehlhofer, Rolf H.(1999). *Combined-Cycle Gas and Steam Turbine Power Plants*: pg 15-26. Tulsa, Pennwell publishing

output needs until nuclear power becomes more widely accepted.

Power Plant Costs

The cost of constructing and operating a power plant is a large undertaking. However, as stated before, it is a much cheaper alternative in the long run than purchasing power. The capital investment for a 1000 MW power plant is just over \$400 per kilowatt (kW), or \$500 million with a 1.2 cost index³⁵. The power plant can be constructed in 20 months³⁶. Therefore it will be necessary for construction to begin 20 months before heating begins, and 12 months before the project begins. In addition, there are fixed and variable operating and maintenance costs. Fixed costs are estimated at \$3 million per year, and variable costs for the 1000 MW power plant are near \$3.00 per megawatt-hour. This variable cost ends up being \$86,500 per day, or \$31.5 million per year³⁷. The variable costs include the cost of cooling water. However, due to the condensing and recycling of steam, it reduces the need to purchase large quantities of water. This is very important for a power plant operating in the desert Midwest.

Natural gas is not technically a cost, since it is not purchased. However, there is an opportunity cost, since the gas cannot be sold. The gas necessary to produce the desired power is given by the equation³⁸, $HI = \frac{P}{\eta}$, where P is power, η is the efficiency, and HI is the heat input. The natural gas needed is equal to the HI, in BTU/s, input

³⁵ Kehlhofer, Rolf H.(1999). *Combined-Cycle Gas and Steam Turbine Power Plants*: pg 15. Tulsa, Pennwell publishing

³⁶ Kehlhofer, Rolf H.(1999). *Combined-Cycle Gas and Steam Turbine Power Plants*: pg 26. Tulsa, Pennwell publishing

³⁷ Kehlhofer, Rolf H.(1999). *Combined-Cycle Gas and Steam Turbine Power Plants*: pg 22-23. Tulsa, Pennwell publishing

³⁸ Kehlhofer, Rolf H.(1999). *Combined-Cycle Gas and Steam Turbine Power Plants*: pg 17. Tulsa, Pennwell publishing

divided by the energy in one cubic foot of natural gas, 1035 BTU³⁹. This suggests that we need around 140 MMcf of natural gas, which is about 65% of the 215 MMcf of natural gas produced each day.

Safety

Liquefied Petroleum Gas (LPG) is propane, butane, or a mixture of the two. Both substances are highly flammable and explosive. They are also simple asphyxiates that may cause death due to displacement of oxygen, but only at extremely high concentrations⁴⁰. Heat sources should be kept away from LPG vessels. All structures and vessels with the possibility of LPG concentration buildup should require ventilation equipment for entrance.

In pipelines and other vessels, LPG is kept as a liquid. This requires the vessel or pipeline to be pressurized to keep LPG in its liquid state. Pressurizing the line poses hazards for future excavations in the area of the pipe. This is also true for natural gas pipelines. All LPG and natural gas pipelines must be marked above ground with signage designating a high-pressure pipeline. Additionally, the chance for explosion in pipes increases when LPG is allowed to flow through the pipe in two-phase flow. In an attempt to prevent explosions, PHMSA requires carbon steel pipes to be seamless and specified for high-temperatures, and all fittings must be flanged, threaded, welded or brazed⁴¹.

High voltage electricity is also very dangerous. All electrical line should be properly labeled and insulated and all standard precautions should be used when handling

³⁹ (2006). *Annual Energy Outlook 2006*. Energy Information Administration. Washington D.C. U.S. Department of Energy.

⁴⁰ Marathon MSDS: Propane, Butane, and Iso-Butane

⁴¹ DOT – PHMSA, Operators Manual for LP Gas Systems. <http://www.mapl.com/msds/liqpetro.html>

electrical equipment. There is a special electrical danger associated with the heaters. If they are some how damaged and the heating element is able to short to the casing then an explosion could occur.

Environmental Impact

Though in-situ conversion of oil shale has less negative affects on the environment than other methods of producing oil shale, the impacts are still significant. Oil shale development affects several areas of the environment including humans, land, animals, water sources, and the atmosphere. Though the magnitude of the impacts varies, they all should be considered when developing oil shale production.

The area where the most oil shale reserves are located is in the Green River Formation in Colorado, Utah, and Wyoming. This area does not have a large population of people. Most of the towns are small and have little infrastructure. With a large industrial development like oil shale, there will be a large population growth in the surrounding areas. The rapid population growth would cause a strain on local schools, hospitals, and roads in the area that are not traveled heavily. To mitigate the affects of rapid population growth during the boom of oil shale in the Green River Formation area in the 1980's, the Bureau of Land Management, also known as BLM, set a constraint on the growth rate of small surrounding communities to 5-15% annually.⁴² It is expected that this constraint will once again apply if the oil shale industry is developed to its full potential

⁴²Allegro, Justin. Block, Steve. Facts About Oil Shale And Tar Sands Development. Southern Utah Wildlife Alliance. Retrieved 3/10/06

With a true *in-situ* method of extracting oil from oil shale, it is necessary to heat the kerogen material found in shale rock until it breaks into smaller hydrocarbon chains. This heating process requires several wells spaced an average of 60 feet apart. Also, to protect the surrounding ground water, it is necessary to construct a freeze wall around the oil shale reservoir.⁴² The freeze wall is maintained by environmentally friendly refrigerants that are continuously circulated through several wells that surround the reservoir. Finally, there are also wells that must be drilled to produce the gas and oil that is produced by the slow heating process of the kerogen material. With the several wells that are created along with the surface facilities that are necessary to process the hydrocarbons, the *in-situ* method of extraction uses almost 100% of the surface area above the reservoir that is being produced.⁴³ Most vegetation that currently covers the platted area for production will have to be removed for access by drilling rigs, installation crews, and maintenance crews. After production ends, the wells will have to be plugged and the vegetation will need to be replaced. It is estimated that a plot of cleared and developed land could take ten years to recover.⁴² This could cause long lasting effects on wildlife and other factors including erosion in and around the area of the production site.

In-situ oil shale extraction requires water to cool the oil being produced and also to clear the reservoir of any hydrocarbons that are left before the heaters are turned off and the freeze wall melts. There will be water that is taken from the well initially that can be re-injected, but there will still be a need for water to cool the hot liquid coming from the well. There are small streams that can be used but the amount of water necessary for a full scale operation is larger than that provided by streams. The concerns with using

⁴³ Allegro, Justin. Block, Steve. Facts About Oil Shale And Tar Sands Development. Southern Utah Wildlife Alliance. Retrieved 3/10/06

natural water bodies as supplies are associated with water salinity and temperature increases. The amount of water necessary to run a full scale operation of oil shale production can raise the salinity of surface water significantly.⁴⁴ This has the potential to threaten the survival of many of the animals and plants that have been living in the environment. When water is used for cooling and then entered back into its original source it can raise the temperature significantly. Over time, this temperature increase affects the living organisms in the water. It is not possible for the organisms to adapt quickly to the temperature change. Though these affects are not as visible as others, they are still significant in the analysis of the overall environmental impact of oil shale development.

The production of oil shale requires a large source of energy to operate the electric heaters that are responsible for heating the shale in the ground. The heaters are run by a power plant that produces 800 MW of electricity. The power plant functions by burning natural gas. When natural gas is burned it produces carbon dioxide, a green house gas which is strictly regulated by the EPA. To reduce the amount of CO₂ released to the atmosphere it may be necessary to look into recovery methods. It may be possible to inject the CO₂ into the reservoirs as a secondary recovery method. This would reduce the emissions as well as improve oil and gas emissions.

Economics

The process of extracting oil and gas from oil shale is difficult and complex. As with most cases, this translates to an expensive process. The economics of the process

⁴⁴Allegro, Justin. Block, Steve. Facts About Oil Shale And Tar Sands Development. Southern Utah Wildlife Alliance. Retrieved 3/10/06

below include most of the major costs incurred. The items included in the cost analysis are the equipment, heating, cooling, power plant, well drilling, production taxes, and operating taxes. These are the basic costs of the project if the technology has been proven and is functioning on a commercial level. The analysis does not include logistical costs associated with developing the area where production will be taking place. Therefore, large costs associated with extensive road building, transporting materials, and relocating employees are not included in the analysis. Other costs that are not analyzed are research costs do to the unproven technology and the costs of reclamation. Though all costs are not analyzed, the below estimations will give an idea of what an investment in this particular alternate energy source means economically.

Total Capital Investment

The total capital investment for the project involves the cost of purchasing the equipment needed for the processing and power generation, direct costs associated with installing the equipment, and the indirect costs. The indirect costs and direct costs are found from multiplying certain percentages times the total purchased equipment costs. These percentages are taken from PT&W and are based on industry averages. These calculated costs should be within thirty percent of the actual value of the costs. This error must be accounted for in the risk assessment. Below, in Table 9, it is possible to see that the total purchased equipment cost is \$541 million. The largest expense in this particular section is the power plant that is built to operate the heaters and refrigeration system. The direct cost total is equivalent to \$225.5 million. The largest cost in this section is directly related to the cost of the pipelines. The pipeline cost includes every pipeline that is installed in the gathering system as well as those that are being use to send the products

to market in Denver. The indirect cost total is \$59 million. This is relatively lower than the other costs. All of the calculations in this section are based on the predetermined percentage values from PT&W. Based on all of these costs and the working capital, the total capital investment for the project is \$867 million.

Table 9: Total Capital Investment. Project estimation for total capital investment.

Total Purchased Equipment Cost		
Component	Basis of Estimation	Cost
A. Purchased Equipment		
1. <i>Extraction Equipment</i>		
k. Heaters	25/acre @ \$100,000	\$25,000,000.00
l. Refrigeration plant	800 KW capacity	\$12,500,000.00
a. Pump	80, 1.6M gal/hr water, 2 weeks	\$1,840,000.00
	Extraction Equipment Costs	\$39,340,000
2. <i>Processing Equipment</i>		
a. Heat Exchangers	5 w/ SA=1500ft ² , \$15,867	\$80,000
b. Distillation	D=3m, H=6m, 10 trays	\$87,000
c. Mixer #2	D=.508	\$16,000
d. Mixer #1	D=.4572m	\$14,000
e. Flash #1	D=1m, H=10m	\$15,000
g. Pump	.0544 m ³ /s, 6800 kPa	\$40,000
h. Pumps (piping)	2 w/ .151 m ³ /s, 1035 kPa	\$32,000
i. Heat Exchangers	3 w/ SA= 100 ft ²	\$3,600
j. Expander	P=1932 kW	\$235,000
k. Expander #2	P=552 kW	\$105,000
m. Compressor	5800 kW, centrifugal-rotary	\$1,100,000
	Processing Equipment Costs	\$1,727,600
3. Power Plant	Combined Cycle, \$400/kWh	\$500,000,000
	Total Purchased Equipment	\$541,067,600
B. Direct Costs		
1. Equipment Installation	47% of processing equipment	\$19,302,000
2. Instrumentation and controls	36% of processing equipment	\$14,784,000
3. Piping (installed)	variable	\$173,840,000
4. Electrical systems (installed)	11% of processing equipment	\$4,517,000
5. Buildings (including services)	18% of processing equipment	\$7,392,000
6. Roads	\$20,000/mile	\$200,000
7. Land Lease	\$2/acre	\$100,000
8. Yard Improvements	3% of process equipment	\$1,232,000
9. Service Facilities (installed)	10% of processing equipment	\$4,107,000
	Total Direct Costs	\$225,474,000
C. Indirect Costs		
1. Engineering and Supervision	33% of processing equipment	\$13,552,000
2. Construction expenses	41% of process equipment	\$16,838,000
3. Legal Expenses	4% of processing equipment	\$1,643,000
4. Contractor's Fees	22% of processing equipment	\$9,035,000
5. Contingency	44% of processing equipment	\$18,070,000
	Total Indirect Plant Costs	\$59,138,000
D. Fixed-Capital Investment		\$825,680,000
E. Working Capital	5% of FCI	\$41,284,000
Total Capital Investment		\$866,964,000

Total Annualized Cost

The total annualized cost is calculated for what is considered full production which is 80,000 bpd. The total annual cost includes the manufacturing costs as well as general expenses. As displayed in Table 10 below, the raw materials include the cooling water used for the heat exchangers as well as the drilling, refrigeration, and operating labor. The drilling costs are included in the annual cost because there will be a drilling program continuously in operation every years. The refrigeration system is also an annualized cost do to the fact that it is recurring.

The largest cost in the total annualized cost is from the production taxes. The Bureau of Land Management as well as the state of Colorado tax petroleum production very heavily. The Bureau of Land Management is leasing the land on which the project is taking place for \$2 per acre at the current time. After production begins, a tax of 12.5% of the gross profit must be paid to the Bureau of Land Management, BLM⁴⁵. In addition to the BLM, there is a state production tax in Colorado of 1% of the gross profit⁴⁶. These taxes are included in the total annualized cost because they are charged for the amount of production.

The depreciation that is accounted for in the total annualized cost is based off of straight line depreciation over twenty-five years. Most of the other values found in table 10 are from percentages taken from PT&W. These values should be with in thirty percent of the actual prices that would be found when constructing the site. The total annualized cost is \$678 million which corresponds to a cost per barrel of \$23.21. Once

⁴⁵ Oil and Gas Leasing Instructions. Bureau of Land Management. Retrieved 3/9/06.
<http://www.co.blm.gov/oilandgas/leasinstruct.htm#FAQ>

⁴⁶ Colorado Department of Revenue, Taxpayer Service Division, Retrieved 3/9/06.
<http://www.revenue.state.co.us/fyi/html/withld04.html>

again this amount can be attributed to mostly the production taxes that accounts for 37% of the cost.

Table 10: Total Annualized Cost.

<i>I. Manufacturing Cost</i>		
A. Direct Production Costs		
1. Raw Materials		
a. Cooling Water	178M lb/hr \$0.08/1000kg	\$1,650,000
2. Operating Costs		
a. Drilling Costs (contract)		\$22,400,000
b. Operating Labor		\$2,000,000
c. Refrigeration	\$0.68 per KW	\$196,000,000
	<i>Total</i>	\$220,400,000
3. Direct Supervision and Clerical	15% of Operating Labor	\$300,000
3. Utilities (Power Plant)		
a. Variable Operating Costs	\$86,500/day	\$31,572,500
b. Fixed Operating Costs	\$3.6M/year	\$3,600,000
4. Maintenance and Repair	7% of FCI	\$57,798,000
5. Operating Supplies	15% of Maintenance and Repair	\$8,670,000
6. Laboratory Charges	5% of Operating Labor	\$100,000
7. Patents	not applicable	\$0
B. Fixed Charges		
1. Capital Costs	Straight Line Depreciation, 25 years	\$33,027,000
a. BLM Production Tax	12.5% of Gross	\$228,617,750
b. Insurance	.7% of FCI	\$5,780,000
c. State Production Tax	1% of Gross	\$18,289,420
C. Overhead Costs	10% of the Total Product Cost	\$56,000,000
<i>II. General Expenses</i>		
A. Administration Costs	20% of Operating labor and maintenance	\$11,960,000
	<i>Total Annual Cost</i>	\$677,800,000

Price Forecasting

Using predictions from the energy information agency, it is possible to calculate the average price of oil, gas, and LPG in the future. Figure 23 below displays future predictions for the prices of these three commodities listed above. From this graph, it is possible to estimate that the cost of oil will be on average \$57/bbl, the cost of gas will be \$4.50 per 1000 cubic feet, and the cost of LPG will be \$1.40 per gallon. Using these

estimated values, the revenue from sales for the twenty five years that the project is under consideration.⁴⁷ With the current prices that are being seen, the price estimates for the the oil, gas, and LPG seem to be low. Though the estimations are consistent with the Energy Information Agency, they are being used because it ultimately lowers the overall risk of the investment. The inflation is added into the prices during the calculation at a rate of 4% per year.

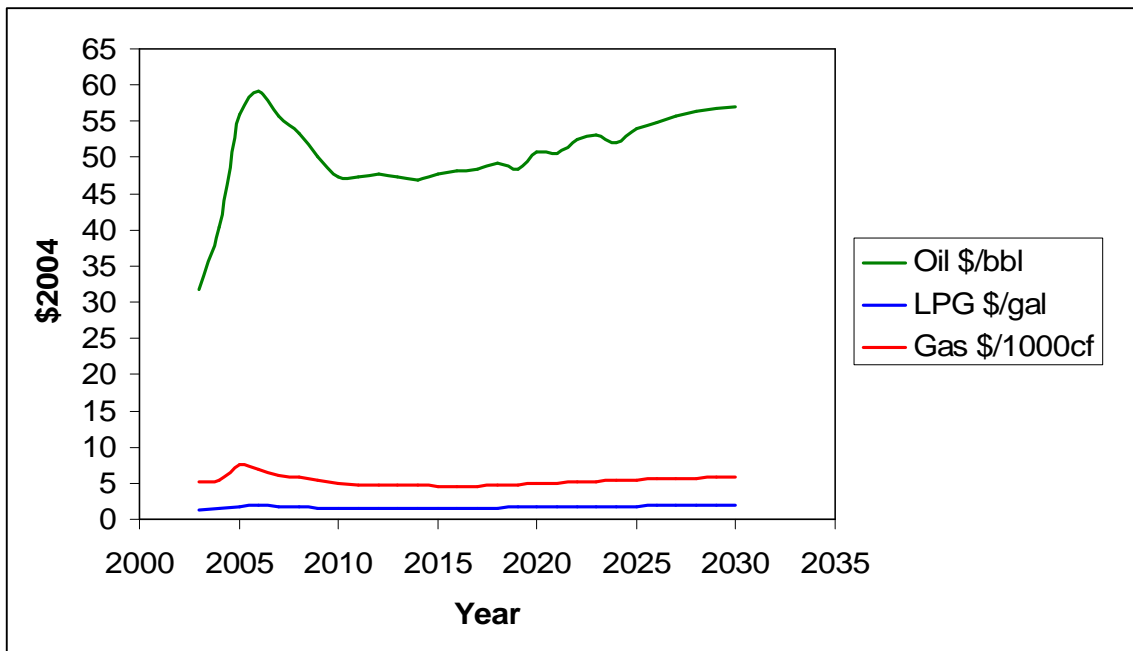


Figure 23: Future Commodity Prices (Energy Information Agency, Annual Energy Outlook 2006)

Figure 23 has the expected value of crude oil, LPG, and natural gas. The values are the median case obtained from the Energy Information Agency's *Annual Energy Outlook 2006*. All prices are in 2004 dollars; therefore, they do not reflect inflation.

⁴⁷ (2006). *Annual Energy Outlook 2006*. Energy Information Administration. Washington D.C. U.S. Department of Energy.

Annual Cash Flow

Table 11 displays the annual cash flow for the twenty-five years of the project. Year one represents the beginning of the project and year four marks the beginning of production. During these four years very large losses are incurred because of the large investment that is necessary in developing the site. Approximately \$2 billion is lost in addition to the \$573 million in capital investment, before a profit comes to fruition. The product cost increases in year five when the second tract of land begins producing and year five when a constant product cost is achieved as two tracts are in constant production. This causes a revenue for the first time during these two time periods as seen below. The annual cash flows below includes a 4% inflation rate.

Table 11: Annual Cash Flows with 4% Inflation

Year	Revenue	Annual Product Cost	Annual Cash Flow	ROI	Net Income
1	\$0	(\$609,800,000)	(\$609,800,000)	-168%	(\$609,800,000)
2	\$0	(\$634,192,000)	(\$634,192,000)	-175%	(\$634,192,000)
3	\$0	(\$659,560,000)	(\$659,560,000)	-182%	(\$659,560,000)
4	\$300,648,000	(\$685,942,000)	(\$385,294,000)	-106%	(\$385,294,000)
5	\$1,139,956,000	(\$713,380,000)	\$426,576,000	118%	\$426,576,000
6	\$1,828,942,000	(\$1,483,830,000)	\$345,112,000	95%	\$345,112,000
7	\$1,902,100,000	(\$1,543,183,000)	\$358,917,000	99%	\$358,917,000
8	\$1,978,184,000	(\$1,604,910,000)	\$373,274,000	103%	\$373,274,000
9	\$2,057,311,000	(\$1,669,106,000)	\$388,205,000	107%	\$388,205,000
10	\$2,139,603,000	(\$1,735,870,000)	\$403,733,000	111%	\$403,733,000
11	\$2,225,187,000	(\$1,805,305,000)	\$419,882,000	116%	\$419,882,000
12	\$2,314,194,000	(\$1,877,517,000)	\$436,677,000	120%	\$436,677,000
13	\$2,406,762,000	(\$1,952,618,000)	\$454,144,000	125%	\$454,144,000
14	\$2,503,032,000	(\$2,030,723,000)	\$472,309,000	130%	\$472,309,000
15	\$2,603,153,000	(\$2,111,952,000)	\$491,201,000	135%	\$491,201,000
16	\$2,707,279,000	(\$2,196,430,000)	\$510,849,000	141%	\$510,849,000
17	\$2,815,570,000	(\$2,284,287,000)	\$531,283,000	146%	\$531,283,000
18	\$2,928,193,000	(\$2,375,658,000)	\$552,535,000	152%	\$552,535,000
19	\$3,045,321,000	(\$2,470,684,000)	\$574,637,000	158%	\$574,637,000
20	\$3,167,134,000	(\$2,569,511,000)	\$597,623,000	165%	\$597,623,000
21	\$3,293,819,000	(\$2,672,291,000)	\$621,528,000	171%	\$621,528,000
22	\$3,425,572,000	(\$2,779,183,000)	\$646,389,000	178%	\$646,389,000
23	\$3,562,595,000	(\$2,890,350,000)	\$672,245,000	185%	\$672,245,000
24	\$3,705,099,000	(\$3,005,964,000)	\$699,135,000	193%	\$699,135,000
25	\$3,853,303,000	(\$3,126,203,000)	\$727,100,000	200%	\$727,100,000
Total	\$55,902,957,000	(\$47,488,449,000)	\$8,414,508,000	93%	\$8,051,544,000

The cash flow chart above gives several indications that this investment is profitable. Though there is a large initial cost incurred, the final outcome of the project proves to be lucrative. The average return on investment based on the cash flows is found to be 93%. The final cash flow at the end of twenty five years is determined to be \$8 billion. Graphing the cash flows over a period of time, as illustrated in Figure 24, displays that the total amount of time that it takes to pay out the initial investment is 9.7 years. Using the cash flows, it is possible to calculate the net present value at the commencement of the twenty-five years. This value, using an 8% discount rate was found to be \$1.5 billion. All of these factors contribute to the decision that this project will be very profitable and should be invested in. However, there has been no

consideration yet in how the price of the selling products will vary and how much it will affect the overall profit. This factor will be assessed in the next section.

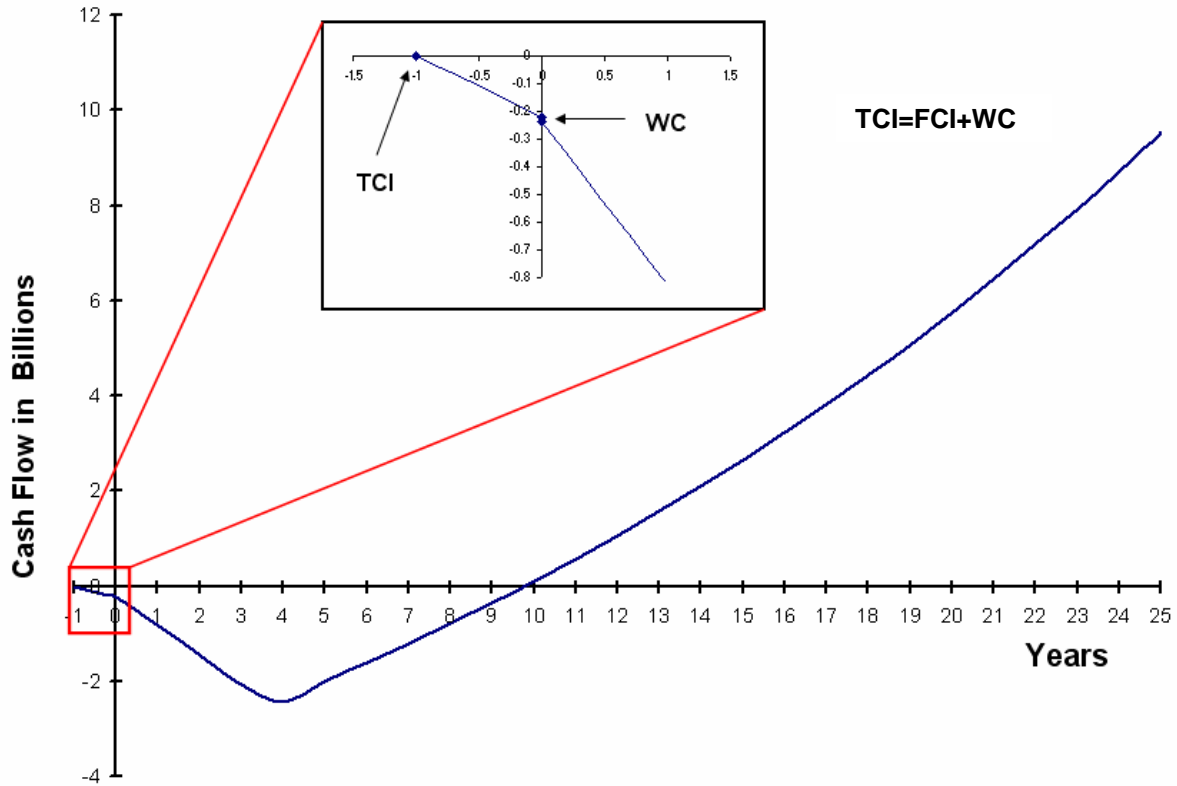


Figure 24: Cash Flows vs. Time. Graphical representation of the cash flows over the twenty five year period of the project.

Risk Assessment

There is a great deal of risk involved in any oil and gas project. However, with almost \$3 billion invested in a project before any production is realized, this project has a much higher risk than many others. Risk analysis was performed on the economics described in the previous sections. The software used was Palisade’s @Risk 4.5. The risk inputs were the equipment costs, operating costs, and prices of oil, LPG, and natural gas. All of these products were varied using a normal distribution. The variations were

used to determine the risk of the project based solely on product selling price variations and equipment cost variations.

Figure 25 below displays the risk distribution for the net present value. As displayed below, the mean net present value is \$1.45 billion. Though the mean is definitely well above zero, it must not be ignored that there is a very large chance of losing money according to this distribution. Within the 90% confidence interval, there is a possibility of having a negative net present worth of about \$1.5 billion. While overall the graph seems to be displaying a favorable decision for the project, it still must be noted that there is a high chance of losing several billion dollars.

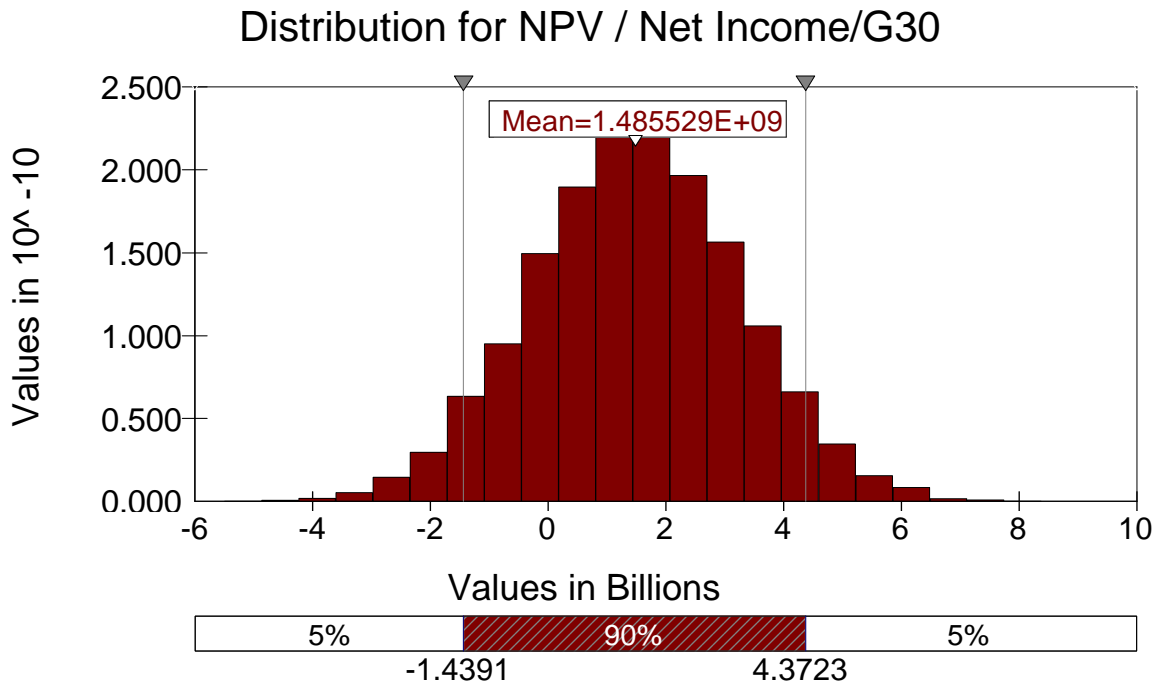


Figure 25: Net Present Value Risk Distribution for 8% Discount Rate. Displays probabilities of different NPV with a 90% confidence interval.

The risk can also be analyzed by looking at the variation in the return on investment as the prices of the products change. In Figure 26, the mean return on investment for the project is found to be 0.93. This return on investment is very high.

The risk for actually having a negative ROI is around 10%. This is low, but must be taken into consideration when looking further into the decision process.

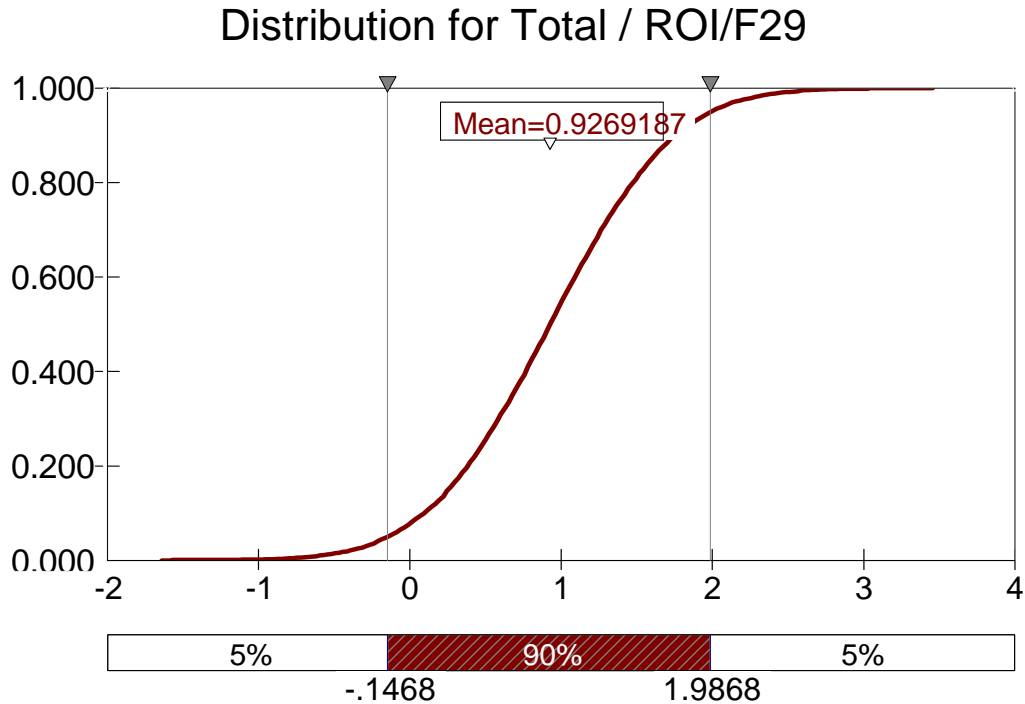


Figure 26: Risk Curve for Return on Investment. Displays cumulative probabilities.

Alternative Discount Rates

In the previous calculations, the discount rate was set at 8%. To make a final assessment on the investment, it is necessary to know how sensitive the net present value is to the change in discount rate. As the discount rate continues to increase, the net present value will decrease significantly. Table 12 displays the dramatic affect. As the rate reaches 15% the net present value has already declined to \$2 million. When the discount rate reaches 15.6%, the net present value goes to 0. This can affect financing of the project and ultimately the decision whether to invest in it or not.

Table 12: NPV Responses to Change in Discount Rates

Rate	NPV (25 years)
0.08	\$1.9 billion
0.10	\$1.2 billion
0.12	\$0.7 billion
0.15	\$0.2 billion

By varying the sales prices of the products and the equipment prices, it is possible to once again look at the risk curves associated with the three new cases of different rates of return. Below are the graphs for these three extra cases.

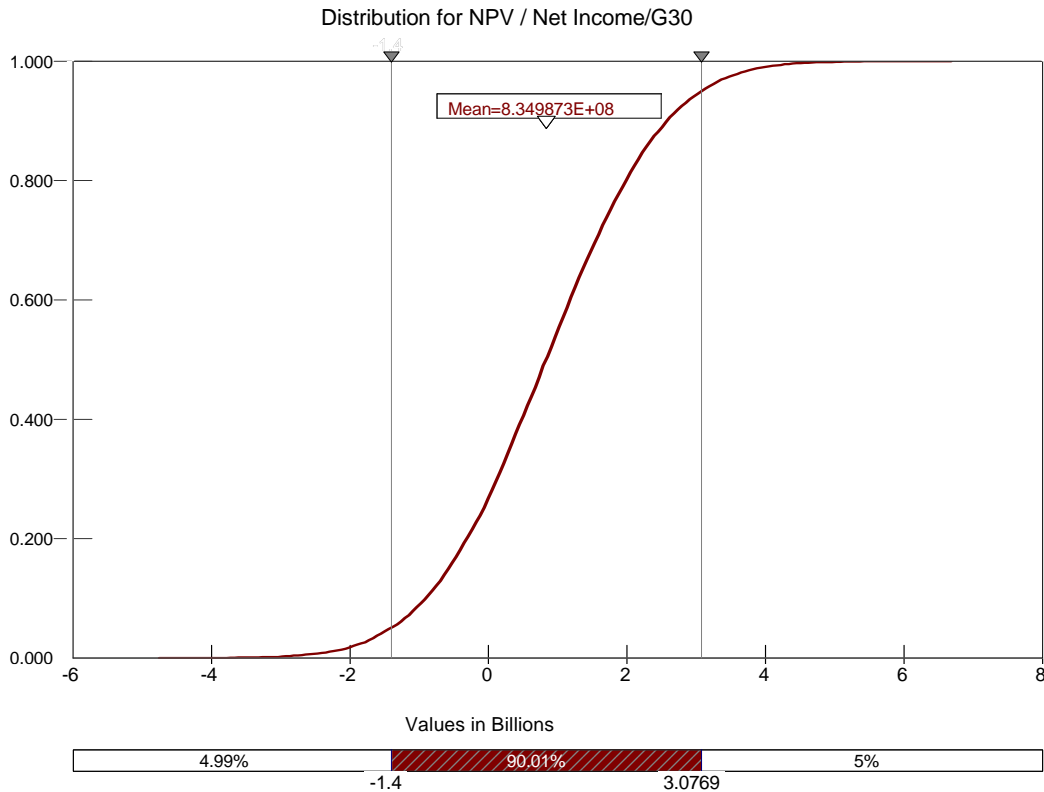


Figure 27: Risk Curve for NPV at Discount Rate of 10%.

The risk curve generated for the 10% discount rate displays a mean net present value of \$835 million but has about a 20% chance of losing money. With this discount rate, the overall outcome is still favorable; however, there is a considerable chance of losing the initial investment in the project.

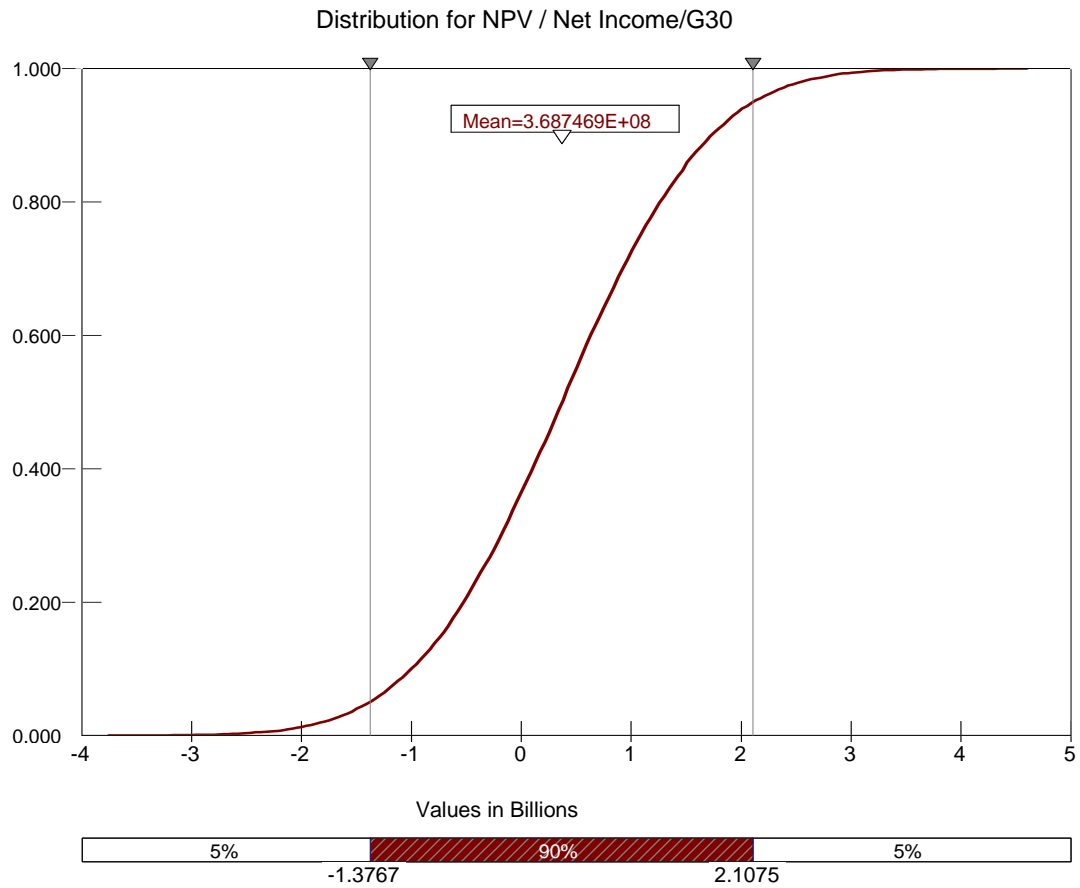
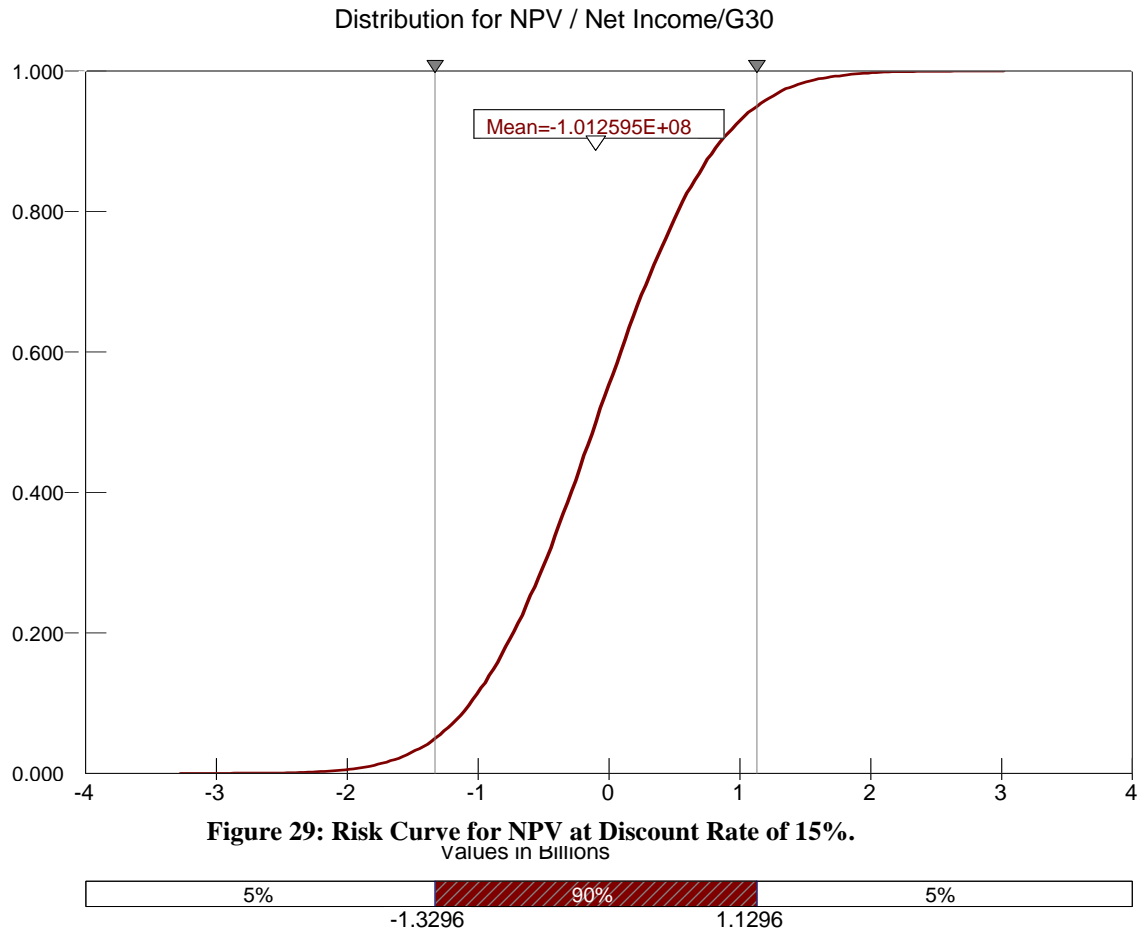


Figure 28: Risk Curve for NPV at Discount Rate of 12%

With a discount rate of 12% the mean NPV is determined to be \$368 million. The value is still positive, but the chance of having a negative NPV continues to grow. In this particular case, the chance of having a negative NPV is high at 35%.



This final curve displays the risk of the net present value at a discount rate of 15%. This example displays that there is more than a 50% chance of having a negative net present value. The mean of this particular risk curve displays a negative value of \$101 million. With this particular discount rate, the process would be less likely to be invested in by a company because the chance of losing the investment and not making money is high.

Future Work

This study is an initial look into the characteristics of the reservoir, subsurface equipment, and surface facilities. All of these particular subjects can and will need to be studied in more detail to determine the optimum operating conditions of the project as well as the best option for use of the gas and oil products.

The first major issue that will need to be addressed in more detail is the cost of the infrastructure needed to produce shale oil in western Colorado. There is limited access to this part of the state where the shale oil deposits are found and therefore, many roads, schools, towns, and even railroads will need to be constructed to transport the products of a commercialized project and supply the needed infrastructure for the influx of people. These costs will have a large affect on the overall economic analysis of the project.

Once a working composition model is developed, there will be a large amount of room for optimization work in the project. This optimization work will include heater spacing, temperature, the heating element, and the heating time. Because all of these characteristics will ultimately affect how quickly and what hydrocarbons are produced from the reservoir, they have a direct affect on the cost and profit of the project. All of these characteristics can be optimized to ultimately develop the optimum operating conditions for the project sites.

There are several options for the gas products that can be considered. Some of the gas that is produced will be used to power the plant that operates the heaters and other equipment on site. There is a possibility to build a gas processing facility as well as to build a plant to make ethylene from ethane. The LPG can be separated from the other products and be sent with the oil for sale in Denver. The final option is to build a refinery

that will process the oil and gases being produced for sale. An economic analysis and optimization on all of the options will need to be carried out to determine which option will be the most profitable.

Recommendations

Surmounting the technical challenges required to achieve commercial production of shale oil is a difficult task, but when it is accomplished a very large profit will be realized. After 25 years the project has a net present value of \$1.5 billion and a cumulative return on investment of 93%. The process also has an annual cash flow in the neighborhood of \$800 million. Though the economic numbers look promising, the true decision of investment in this project will be dependent on the technology being proven and implemented on a commercial level. A risk assessment based on changing product sales prices illustrates that if the rate of discount is 8%, the mean net present value will be \$1.5 million and the mean ROI will be 93% as well. There is however still a risk of about 10%-15% that these two values will be negative. If the technology as well as logistical costs were included in this risk assessment, the percent of loss would probably be much higher.

Because of the experimental stage of the in-situ production of shale oil, more research and analysis on the results of the experiment will need to be evaluated. There may be a higher risk of losing money depending on the difficulty associated with keeping the heaters powered, finding water resources, and analyzing the real risk of contamination of the water supply due to a faulty freeze wall. Though there are many challenges associated with the production of shale oil, the initial economic analysis points towards

developing shale oil with the in-situ method. It is a large upfront investment, but the ultimate product looks favorable.