Economics of Oil Mining by Gravity Drainage

by

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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science (Mineral Economics).

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ABSTRACT

Oil mining by gravity drainage, one of the enhanced oil recovery methods used to attempt to reach the approximately two thirds of the original oil in place left after conventional recovery, can play a substantial role in increasing the nation's oil reserves. Economic discoveries by conventional exploration are becoming more difficult. Conventional exploration costs, which can be entirely avoided by oil mining, have been estimated in the range of \$12 to \$15 per barrel of oil discovered (Adkerson, 1983). Companies, as well as the nation on an overall basis, are hard pressed to replace or maintain their proven reserve base. Approximately 300 billion barrels remain at the end of present recovery processes (Nehring, 1978). Of this total unrecoverable resource, it is estimated that 64 billion barrels are in reservoirs which are amenable to the oil mining by gravity drainage technique (Recovery of Oil By Mining, 1984). Present economics prevent raising the capital cost of a pilot oil mining project in the private capital markets.

This research includes a review of past and present oil mining endeavors. Diagrams of the world's most technically advanced oil mining project, located in Russia, are set forth. A detailed financial analysis of a proposed United States oil mining project is evaluated. The base case indicates a financial return (Discounted Cash Flow Rate of Return) of 28%.

The sensitivity analysis points out that the price of oil is not necessarily the most important parameter affecting the financial outcome. The parameters that most strongly affect the returns are the percentage recovery of the oil in place, the length of time it takes to recover this oil, and the operating costs. The most important tax consideration is the 15% depletion allowance. Specific recommendations for further areas of research are made. The high return indicated means continued investigation is warranted.

A wise national energy policy would not allow this resource to be wasted and would include whatever financial assistance is necessary to establish an oil mining pilot project in order to advance the technology.

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ACKNOWLEDGMENTS

I would like to dedicate this thesis to Dr. Charles W. Berry who pointed this student in the right direction and whose continued kindness and thoughtfulness made the completion of this thesis possible. Many thanks to Drs. John D. Wright and Oded Rudawsky for their counsel and their instruction over the years.

I would like to gratefully thank John T. McClimans for his artistic skills and dedication in preparing the mine plans and drawings found in this thesis.

Many thanks to Lita Dunham for her valuable assistance in putting this thesis in readable form.

CHAPTER 1

INTRODUCTION

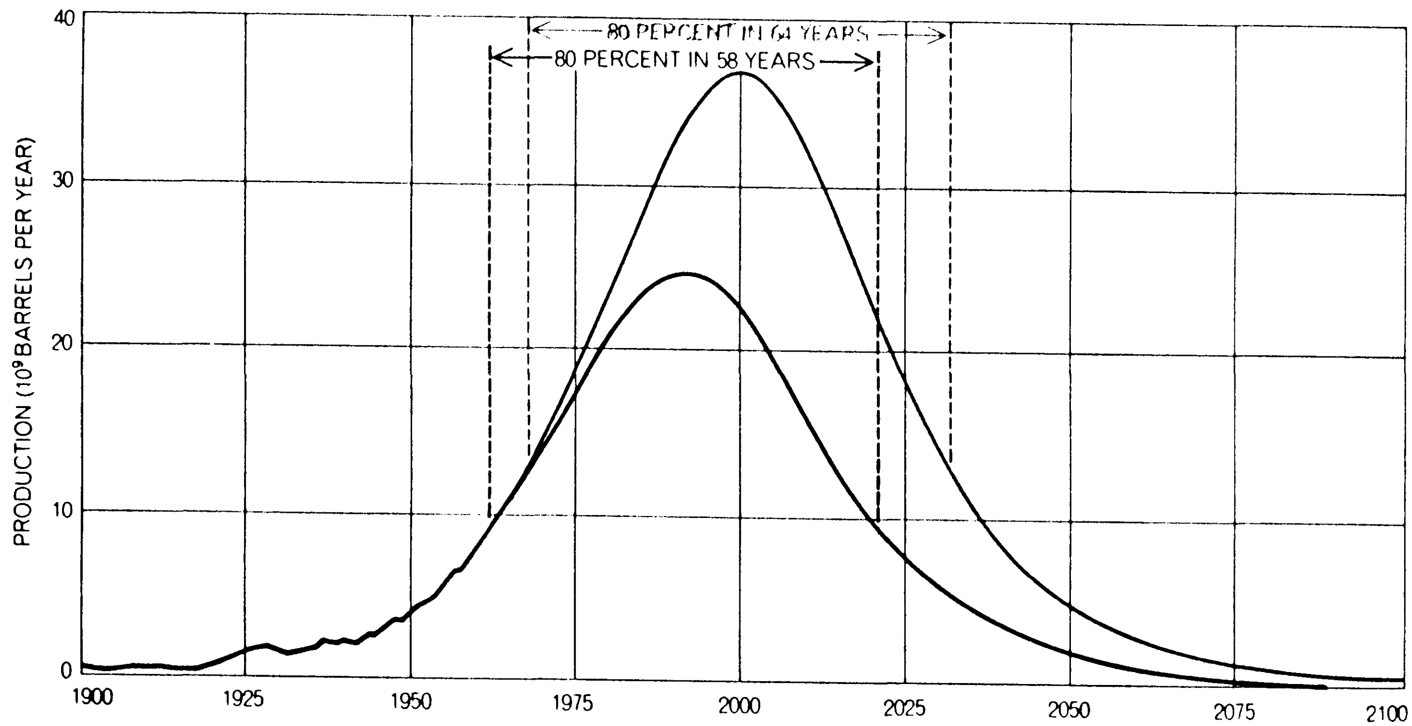
Statement of the Problem

This thesis attempts to show that oil mining by gravity drainage can play a substantial role in increasing U.S. supplies of oil to meet future domestic consumption requirements. Finding oil and gas in the past required substantial exploration creativity. In the future, finding oil and gas in the United States will require more creativity in enhanced oil recovery techniques and in oil recovery methods. Oil mining by gravity drainage is one method which is technically feasible but whose economics are questionable because of lack of experience in the field. The effort must be made to reach that two-thirds of the resource that presently remains unrecoverable in the reservoirs after using conventional methods. This can only be accomplished with government financial assistance for a pilot project due to the present economics facing the oil industry.

During the last 600 million years, organic material buried under great thicknesses of sedimentary sands, muds, and limes formed energy-rich but finite deposits of coal, oil shale, petroleum, and natural gas. Industrialization has necessitated withdrawals from this energy bank with increasing rapidity. Since the turn of the century, the world's consumption of energy for industrial purposes has doubled approximately once each decade.

According to M. King Hubbert, (1971) the complete cycle of exploitation of a fossil fuel reserve has the following characteristics. Beginning at zero, the rate of production tends to increase exponentially. Then, as the difficulties of discovery and extraction increase, the production rates slows, passes one maximum or more and, as the resource is progressively depleted, declines eventually to zero. If the past and future rates of production are combined with a reasonable estimate of the amount of fuel initially present, one can calculate the probable length of time that the fuel can be exploited. See Figure 1.1

The United States is well into that part of the curve shown in Figure 1.1 where it is unable to find and produce enough oil to replace the quantities used each year. The nation's past experience has shown that making up this deficit through foreign imports is risky, at best. Recovering the two-thirds of the oil that remains after primary, secondary, and enhanced oil recovery techniques have been employed is one method of closing the gap between



CYCLE WORLD OIL PRODUCTION is plotted on the basis of two estimates of the amount of oil that will ultimately be produced.

The top curve reflects Ryman's estimate of 2,100 x 10^9 barrels and the black curve represents an estimate of 1,350 x 10^9 barrels.

Figure 1.1

Cycle of World Oil Production

Source: Adapted from M. King Hubbert, "The Energy Resources of the Earth," Energy and Power San Francisco, W. H. Freeman and Company, 1971 production and consumption. Using mining technology to reach some of this resource and petroleum technology to extract it is a logical step to avoid waste.

The principle that the petroleum resource exists in a finite quantity indicates that only a finite number of oil and gas fields exists in a given area (Hubbert, 1971). As exploration proceeds, the shallowest and most evident fields are usually discovered first. The amount of exploratory activity required to discover a fixed quantity of gas or oil steadily increases over time; or putting it another way, the amount of oil or gas discovered for a fixed amount of exploration activity declines steadily over the years.

History and Literature Survey

Oil mining is not a new development. The methods used in the past were basic or crude when measured against today's technologies. As early as 5000 B.C., the Egyptians used bitumen to mummify their pharaohs. The ancient historian, Heredotus, cited an operation in Persia where oil, salt, and bitumen were extracted from shallow wells and short drifts as early as 450 B.C. (Energy Development Consultants, 1978). In the modern era, France and Germany, not being oil-rich nations, mined oil to augment their limited resources. In 1932, George Rice, the chief mining engineer of the U.S. Bureau of Mines, studied these operations and concluded that 60% to 80% of the resource could be reached by mining oil as opposed to leaving it in the ground after all surface pumping methods were applied (Rice, 1932).

The Soviet Union has developed a mine which combines undergound mining with thermal stimulation of the oil to produce oil previously unrecoverable. Though the U.S.S.R. is the world's largest petroleum producer, it has seen fit to spend the time, energy, effort, and money to develop what appears to be the world's most technologically advanced oil mining by gravity drainage operation. This mine design is described in a paper entitled, "Thermally Assisted In Situ Technique of Mining Oil," by Ronald M. Brimhall, prepared for the Society of Mining Engineers of AIME in 1979.

With the OPEC cartel controlling a good part of the world's supply and forcing its price up in 1973, a new look was taken at these older mining methods. Studies made in 1978 by Golder Associates and Energy Development Consultants emphasized that some of the huge resources left underground could be reached by mining technology. Later studies Energy Development Consultants (1983) and

Fuel and Mineral Resources (1984) pointed out that developing the technique will cost considerably less than an oil shale or an oil-from-coal process. The big advantage in oil mining is that the location of the oil is known. Instead of spending millions of dollars to discover new reserves, an investment can be made in the mine workings with assurance of finding the resource. Presently, a tax structure is needed to encourage these efforts and to make it economically feasible to invest the necessary sums to extract the resource.

Research Contribution

A major objective of this thesis is to indicate that government assistance must be sought in order to raise the necessary capital to develop, at the least, a demonstration project. This assistance could come in the form of outright grants, guaranteed loans, tax credits, and other considerations. In addition, a restructuring of the tax code is necessary to allow companies attempting to develop the technique of oil mining the economic incentive to continue. If financial assistance is forthcoming, to cover capital costs and perhaps operating expenses and if the tax code is changed, a new industry could be developed that eventually will return far more to the government than will be given up by the assistance or the tax re-structuring.

CHAPTER 2

MINE DESIGN AND POTENTIAL TARGETS

One possible method of alleviating the nation's declining ability to find and produce domestic oil is the oil mining process. This method uses mining technology to gain close access to the reservoir, and petroleum technology to extract the hydrocarbon from the reservoir (Figures 2.2-2.7). The reservoir material is not treated as "ore" and the material is not removed for processing at a facility that separates the oil from the "sands." The oil reservoir is reached by shafts and tunnels. Once the network of entries is developed, the deposit is reached by drilling a multiple array of drainage holes in an upward fan shape, and the oil is allowed to flow through the drainage holes to a central collecting point where it is pumped to the surface.

The major constraints to the technique are the physical competency and thickness of the rock strata below the reservoir and the temperature of the mine workings. Temperature of the mine workings is a function of the depth of the mine and the geothermal gradient of the area. Some areas of the United States that have oil reserves are considered "hot." These are the Texas-Louisiana coast and

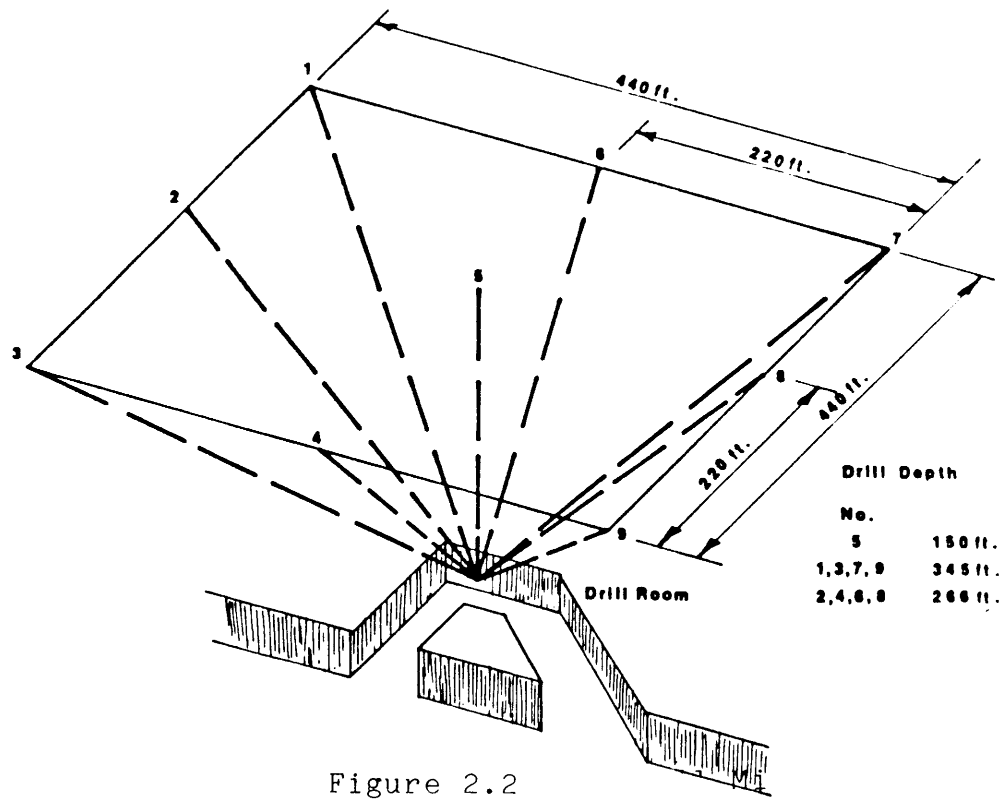


Figure 2.2

Drill Pattern for an Oil Mine

Source: Adapted from Ken. M. Welshimer, "Mining Potential Great in Shallow Fields," Northeast Oil Reporter, October, 1982

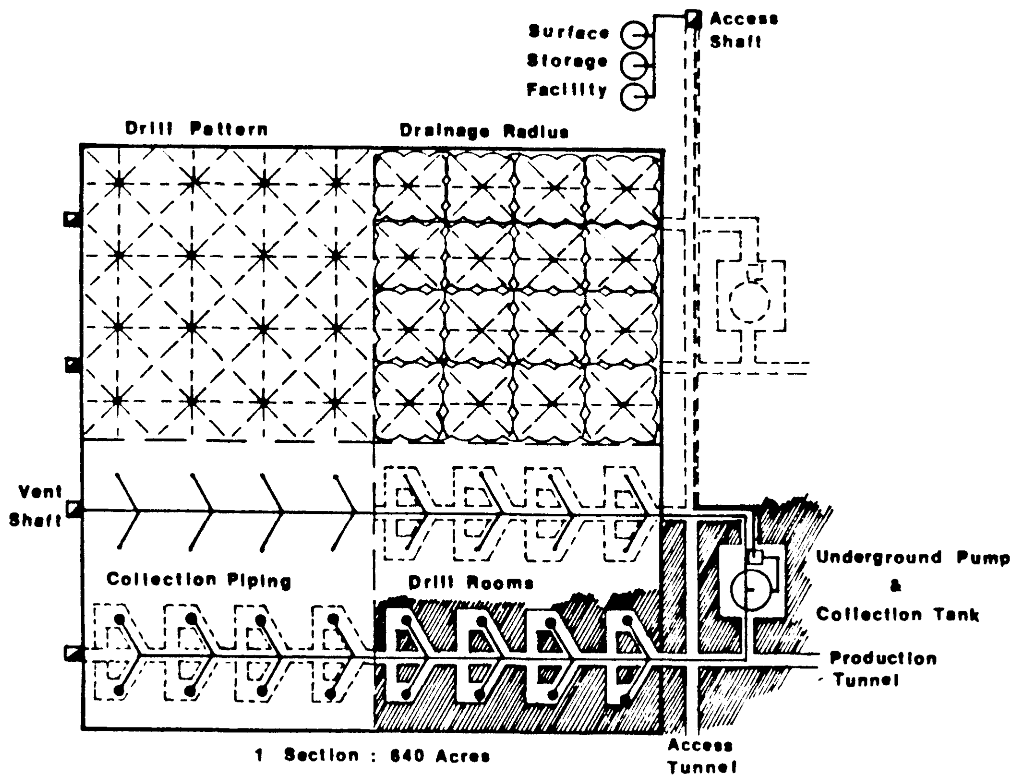


Figure 2.3

Reservoir Gravity Drainage Pattern

Source: Adapted from Ken. M. Welshimer, "Mining Potential Great in Shallow Fields," Northeast Oil Reporter, October, 1982

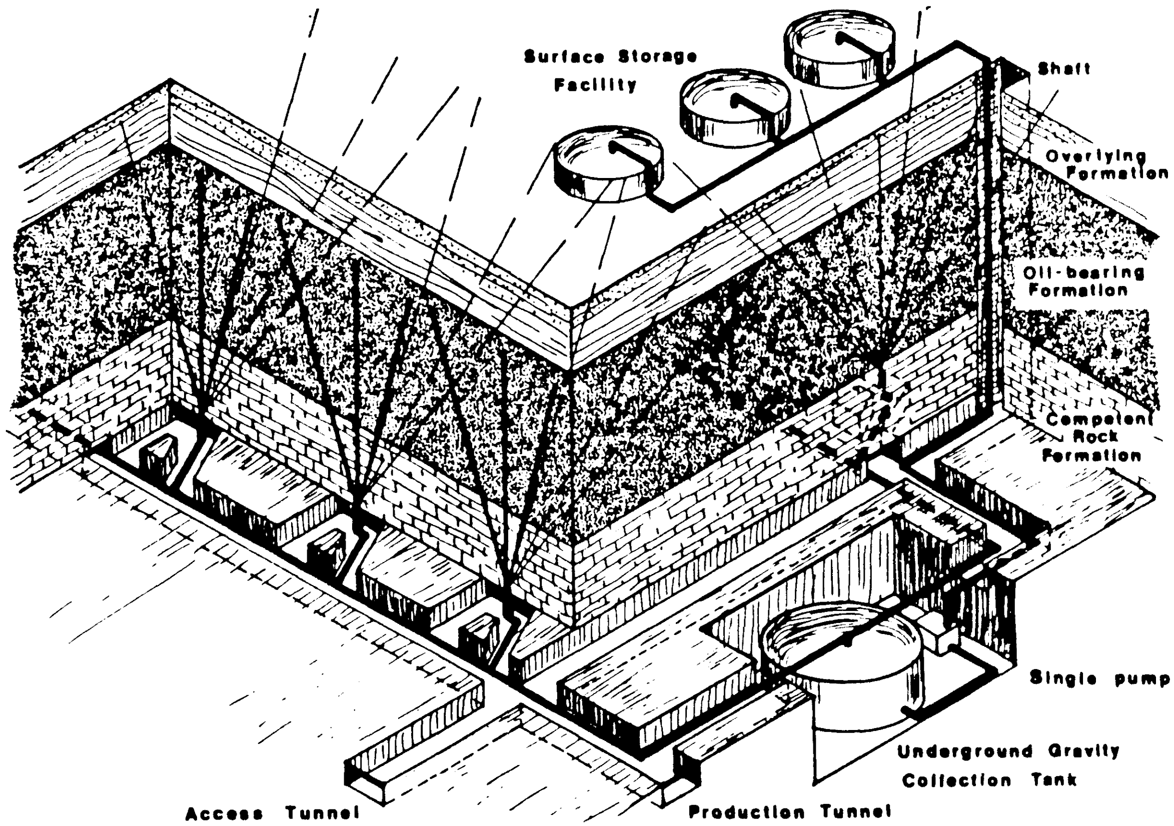


Figure 2.4

Gravity Drainage From Below Formation

Source: Richard A. Dick and Sheldon P. Wimpfen, "Oil Mining," Scientific American Vol. 243, No. 4, W. H. Freeman and Company, San Francisco, 1980

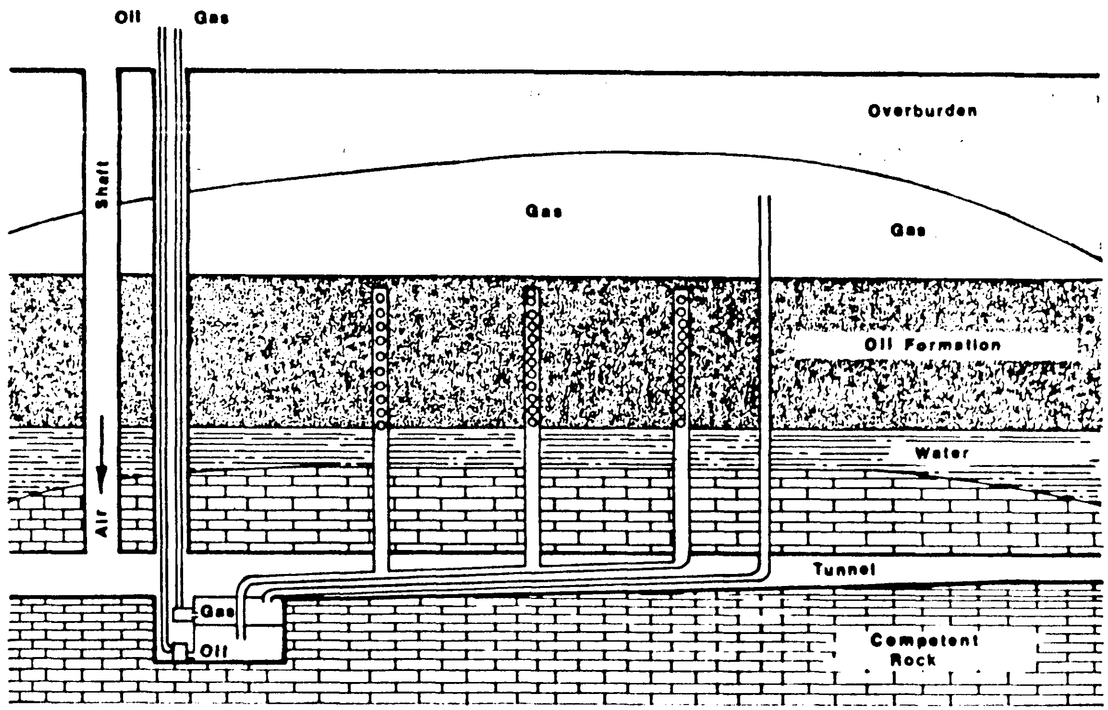


Figure 2.5

Gravity Drainage From Below Formation Side View

Source: Thomas H. Maugh II, "Mining Could Increase Petroleum Reserves," Science Vol. 207, March 21, 1980

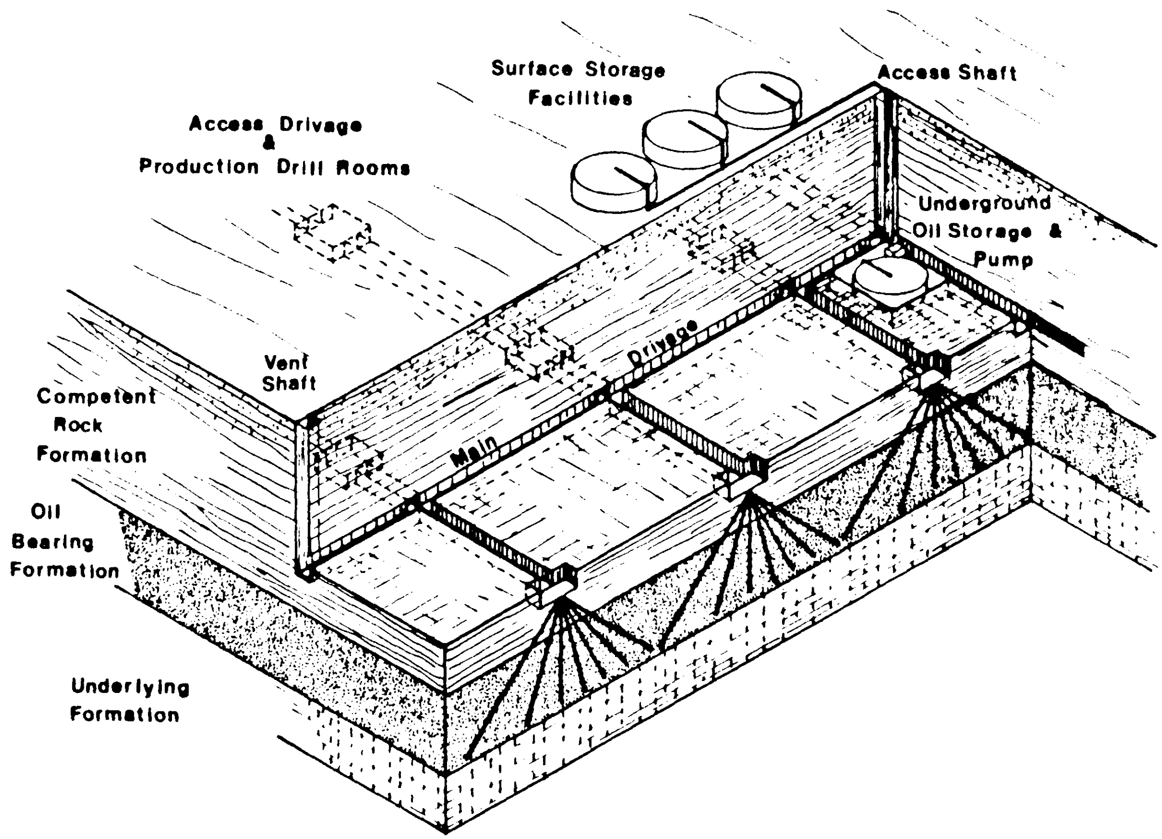


Figure 2.6

Gravity Drainage Mining From Above Formation

Source: Adapted from R. Dick and S. P. Wimpfen, "Oil Mining," Scientific American Vol. 243 No. 4, W. H. Freeman and Company, San Francisco, 1980

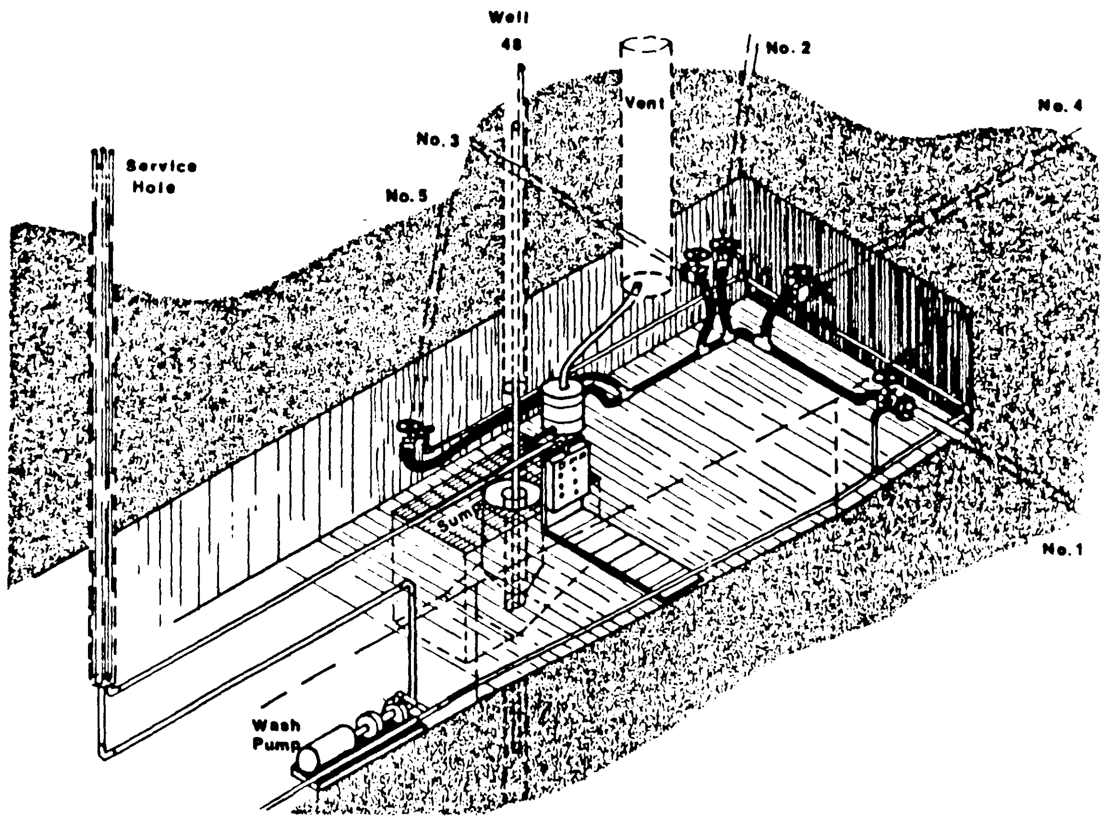


Figure 2.7

Underground Production Equipment

Source: Adapted from W. F. Dobson and D. R. Seelye, "Mining Technology Assists Oil Recovery From Wyoming Field," Journal of Petroleum Technology, February, 1982 the Los Angeles-San Joaquin Valley sections of southwestern California. Mining at depth in these areas will produce high mine operating temperatures. Other areas with petroleum deposits are considered "cool." These are the Permian Basin of West Texas-New Mexico where the mine workings can go much deeper before heat causes ventilation costs to rise. The geothermal gradient is not an absolute or technical barrier to mining at lower depth, but it is a limitation because of the economics. As the mine goes deeper, the increase in overburden pressure requires smaller diameter tunnels to support the overburden stresses. Ventilation requires larger tunnels for larger air flows. These two factors work against each other, indicating a practical depth limit for petroleum mining. The oil sands penetrated by the drainage wells must be at least 10 to 20-feet thick vertically because the hydraulic head must be sufficient for gravity to drive the resource to the drain holes.

When the viscosity of the crude oil is high at natural reservoir temperatures, the production rate will be low. Shallow oil reservoirs, while providing easier access to the deposit, usually have viscous oil. The viscosity of the oil can be reduced by thermal assistance to increase the flow of the oil through the reservoir to the drainage holes. To increase the flow, the spacing of the drainage wells can be placed closer together and made more numerous. However, this increases the cost of the operation. As the viscosity of the crude drops, the optimum well bore spacing increases, lowering the cost of constructing the mine. To calculate the flow or the rate of production, a detailed knowledge of the viscosity of the oil to be produced is required. The equation used to calculate the radial flow of oil into a borehole is given by (Energy Development Consultants, 1983)

$$Q = (7.1659 \times 10^{-4}) \frac{k_O\ h^2 G_O (y^2 - x^2)}{\mu_O \ln(.472 r_e / r_w)}$$

where

Q = The rate of flow of oil from the drainage slot in ft^3 per hour

k_O = The effective permeability of oil in the reservoir, md

μ_O = The viscosity of the produced oil, cp

h = The height of the oil column in the drainage zone, ft

G_O = The specific gravity of the oil

y = The fractional height of the oil column at the maximum drainage radius

x = The fractional oil column height of the borehole

r_e = The well spacing radius of influence (usually 1/2 of the well spacing), ft

r_w = The radius of the well bore, ft

The permeability, the oil viscosity, and the specific gravity of the oil are controlled by the reservoir selected. In some reservoirs, engineering methods can alter the viscosity and affect the rate of the oil flow. The height of the oil column is fixed by the physical character of the oil reservoir selected but may be indirectly affected by injecting steam into the reservoir to increase the pressure on the oil to flow toward the drain holes. Herman Dykstra (1978) stated that laboratory tests have shown that high rates of recovery could be obtained where gravity is an important part of the production mechanism.

The major constraints would appear to be a viscous oil causing a very low rate of recovery and the height of the oil column which is not sufficient to provide enough gravity drive. An oil column that is interrupted by impermeable shale layers will also have a low oil flow rate. Gravity drainage without the assistance of thermal heat may be applicable in a reservoir with a lighter crude oil (lower viscosity) and a sufficiently high oil column to give the oil sufficient drive to reach the borehole. These reservoirs will normally be deeper than those with a more viscous oil.

As mentioned, gravity drainage for heavy viscous oils can be improved by reducing the viscosity of the oil with the injection of steam into the reservoir. A steam drive operation can recover up to 50% of the residual oil in place as contrasted with a steam-soak process where the recovery of the oil in place is in the 5% to 15% range (Energy Development Consultants, 1983). The steam drive process is energy intensive, requiring 200 to 300 barrels of oil per acre-foot of reservoir to generate the required steam at the pressure and temperature necessary to recover that 50% of remaining oil in place. If there is insufficient oil in the reservoir, the cost of generating the steam means it will not be economical to use this method. The overall efficiency of the steam drive method is determined by the ratio of oil produced to the steam injected to produce that oil. When the energy produced is equal to the energy consumed, the ratio is approximately 14 barrels of steam per barrel of oil. This will vary from oil field to oil field because each reservoir reacts differently to the injected steam. The primary factors that affect the efficiency of the steam drive are the oil saturation, the thickness of the reservoir, the steam injection rate, its pressure and quality, and the viscosity of the oil. The limitations of the process are 1) the loss of the steam in the reservoir to "thief" zones which causes the steam to oil ratio to rise, 2) a limited ability for the steam to sweep the reservoir in a vertical direction, 3) heat loss from a water column or thermally conductive cap rock above the oil zone, and 4) the loss of conformance of the steam to the reservoir oil saturated horizon. (EDC, 1983)

In an oil mining process, the steam is injected into a well that is central to eight other producing wells. The oil is either driven from the injection well to the producing well in a semi-vertical "bank" of heated oil, or else it is stripped from the saturated sands by heating a thin layer of oil next to the steam zone thus mobilizing the oil. Ideally, injected steam forms a steam zone around the injection well. As the steam moves away from the well, its temperature drops as it continues to expand in response to the drop in pressure. At some distance from the injection well, the steam condenses and forms a hot water bank. In the steam zone, oil is displaced by steam distillation and steam drive. In the hot water zone, physical changes take place in the oil--thermal expansion, reduction of viscosity and reduction in residual saturation with changes in relative permeability. If gravity override occurs, the steam moves to the upper one-third of the reservoir and the other two-thirds is swept by hot water, resulting in low efficiency. Injection of the steam at the bottom of the reservoir may be effective in reducing override severity, but only when the reservoir properties and oil viscosity are homogeneous throughout the reservoir and no bottom water zone is present (this is an easy conduit for the steam). Using steam is feasible only when the net value of the oil displaced exceeds the cost of heat generation. The rate of heat loss to adjacent strata is one of the most important factors in determining the economic feasibility of using steam. (Lewin, 1981; EDC, 1983) A simplified oil recovery rate can be estimated by the following simple relation (H. K. Van-Poollen and Associates, 1980):

$$\text{Q hot BBLS/day} = \text{Q cold} \frac{(\text{Viscosity before steam})}{(\text{Viscosity after steam})}$$

If breakthrough occurs, and the steam overrides the oil-saturated zone (gravity override), the steam-to-oil ratio can rise to the point where the process is no longer economic. Some research will be necessary on the effect of high pressure steam on the tunnel network below the oil zone.

Unlike in-situ combustion, surface steam injection is a conventional technology. The capital and operating costs are more predictable. The following are some of the risks. (EDC, 1983)

1) The potential for early breakthrough of the steam to the producing wells is high, particularly when narrow production well spacing is used.
2) The production rate when steam is applied to gravity drainage is still uncertain.
3) The creation of a severe water/oil emulsion exists when steam enters into the production wells.
4) The large cost involved for the high pressure steam equipment and the cost associated with generating this steam as compared to the lower cost of low-pressure steam injection.
5) The reservoir must not be deeper than 5,000 feet. This depth limitation is imposed by the critical pressure of steam and a reservoir must be thicker

than 10 feet as the thickness of the reservoir determines the rate of heat loss to the cap rock (inverse proportion).

The cost of operating a gravity drainage process in a light oil reservoir has been estimated at $.56 to $1.00 per barrel (EDC, 1983).

Low pressure steam injection is thermally more efficient than steam drive. It will use 20 to 30 barrels of oil per acre-foot to generate the steam compared with the 200 to 300 necessary under the high pressure method. The advantages of low pressure steam are a low steam to oil ratio, a less critical gravity override, and the lower capital and operating costs. (EDC, 1983)

In the Yarega project in the U.S.S.R., as described by Ronald M. Brimhall, the steam is produced at a central plant on the surface. It is injected at low pressure (75 to 120 psi) from underground steam injection galleries constructed near the main works level at the tunnel bottom just above the oil reservoir. The steam injection wells are drilled downward and outward into the reservoir just above the drainage holes that produce the oil. This causes an intense heating (93^oC, 200^oF) of the area surrounding the injection well which lowers the viscosity of the oil above the drainage wells, reduces the residual oil saturation, causes thermal expansion effects and increases the sweep efficiency due to improvement in the mobility ratio. (Fuel and Mineral Resources, Inc., 1984) The water recovered from the production is recycled. This operation is said to recover 60% of the volume of oil in place, a very high recovery for a low pressure process. (Brimhall, 1979) Its efficiency might be attributed to the underground injection of steam just above the oil reservoir.

In an oil mine, a shaft and a tunnel network are driven. The drainage production wells radiate in an upward fan shape into the oil bearing formation from selected intervals throughout the tunnel network in order to gain access to the oil reservoir. Generally two shafts will be sunk. One shaft is used for the movement of workers, supplies, oil, and waste. The other is used as an escape way and as a ventilator. The shafts can be developed by the conventional method or by mechanized drilling. In conventional shaft sinking, the cycle consists of 1) drilling and blasting, 2) mucking, and 3) installing concrete lining and support. Blind-hole drilling or downboring is done with a rotary drill operated at the surface, eliminating the need for workers in the shaft. The hole is kept filled with a mud mixture while the cuttings are drawn up through the drill stem. With rotary drilling, shaft walls are not fractured or damaged because no blasting is required in the shaft. The disadvantages are the limited hole diameter, the high costs in drilling through hard formations, and the very expensive equipment. Raise boring is another mechanical method. If a shaft and tunnel already exist, a small diameter pilot hole can be drilled from the surface to the mine tunnel. The hole is then upreamed by drilling upwards from the tunnel. As the drilling begins, the cuttings fall to the bottom of the shaft and are removed.

In oil mining, the shaft may have to be sunk through the depressurized oil reservoir. The nature of the oil reservoir may require a shaft sinking method where no workers are required to work underground. In this technique, any encountered pressure pockets, gas, or fluids do not constitute a hazard to the workers. Once the shaft is sunk, it can be lined, or lined as the work progresses, and workers can be hoisted later to a level below the oil reservoir. Grouting is another method that may be useful in sinking a shaft through an oil reservoir. A cementing agent is injected under pressure into the unstable ground to increase its stability and to reduce the rate of fluid flow. The injected material may be cement or a chemical grout that fills small voids and may help to seal fluid flow. In sedimentary formations, cement grout has been used successfully to strengthen the formation and to stop major water flows.

If the formation in which the shaft is to be sunk is extremely incompetent, or if there is considerable water, freezing might be considered. Freeze holes are drilled in a concentric circle with the proposed shaft centerline. A refrigeration system is installed consisting of pumps, circulation pipes, and refrigeration units. The refrigerant is usually a brine such as calcium chloride which is circulated in the ground through the concentric piping system. Once the entire area is frozen, the shaft sinking can begin.

Most shafts are lined with concrete to provide support, protect the wall from deterioration, and to seal out excess water or petroleum fluids. The lining can be done concurrently with the sinking operation or after the excavation is completed. Rock bolts, wire mesh, and gunite can be used as temporary suppport. The exact type of support will be determined by the ground conditions.

Once the shaft has been sunk, a tunnel is excavated under or above the oil reservoir. Its location depends on the reservoir specific geological characteristics. It is from this tunnel that an array of drain holes will be drilled into the oil zone. The tunnel can be driven by the conventional drilling, blasting, mucking, and support installation. The cycle can be interrupted for grouting when necessary. Mining methods for penetrating highly incompetent work may have to be used which will involve the use of concrete and/or steel ribs as the tunnel advances. Rock bolts, wire mesh, and shotcrete may also be used to provide a support in incompetent rock below the reservoir. A tunnel-boring machine, used in place of the conventional tunnel-driving cycle, may result in faster progress. A tunnel-boring machine is designed for a particular tunnel and for the particular rock condition to be encountered. The use of the machine takes the place of blasting and should be used when conditions indicate it to be the most economical method. To put it simply, the machine drives a hole to an exact size instead of roughing it out by the use of the force of explosives. Tunnel boring machines have been successfully used in comparatively soft rock such as limestone, sandstone, mudstone, or shale with a Mohs' hardness scale of less than 4.5. In most reservoirs, this is the type of rock one would generally encounter.

Oil mining on a large scale began at Pechelbronn in 1916 because Germany, holder of the properties, needed oil for the war. In 1919, the oil properties were returned to France and the mining of oil continued under French engineers. (see Appendix C and D) Oil mining at the Wietze mine in Germany was begun in 1919 by the same company that developed the mine at Pechelbronn (France) between 1916 and 1919. The technique of mining oil is an old one. The oil mine operations in Russia, Wyoming and California hereinafter described, as well as the previous operations in France and Germany, indicate it is a technically feasible process.

The Soviet Thermal Oil Mine at Yarega

The Soviet thermal mining method has been in use commercially since 1972. Up to 60% of original oil-in-place is recovered using this technique. Because of the high oil viscosity and the near absence of reservoir energy, only 2% of the oil in place could be recovered by conventional primary well recovery.

Russia seems to have developed the world's most successful and most technically advanced project to date. Its Yarega operation uses steam generated above ground and injected underground just above the oil reservoir

(Brimhall, 1979) See Figures 2.8-2.15. An array of drainage holes is drilled from an underground access tunnel that penetrates the oil sands. The low pressure steam is injected, in close proximity, just above the drain holes. The mining operation is described as follows:

The oil reserves are contained in a consolidated, fine to medium-grained quartz sandstone with conglomerate in some areas at a depth of 180 to 200 meters (590 to 660 feet) below ground level. The rocks are folded with a high degree of fracturing and are also faulted. The thickness of the oil-bearing rock varies from 14 to 27 meters, the average being 21 meters. Some other reservoir characteristics are:

Porosity	20 to 25%
Permeability	.5 to 5 darcies, (average 3.2) darcies
Temperature	6°C (43°F)
API Gravity of Oil	17.5° API
Viscosity	15,000 to 20,000 centipoise at 6°C (43°F). Reduced to 30 centipoise at 93°C (200°F).

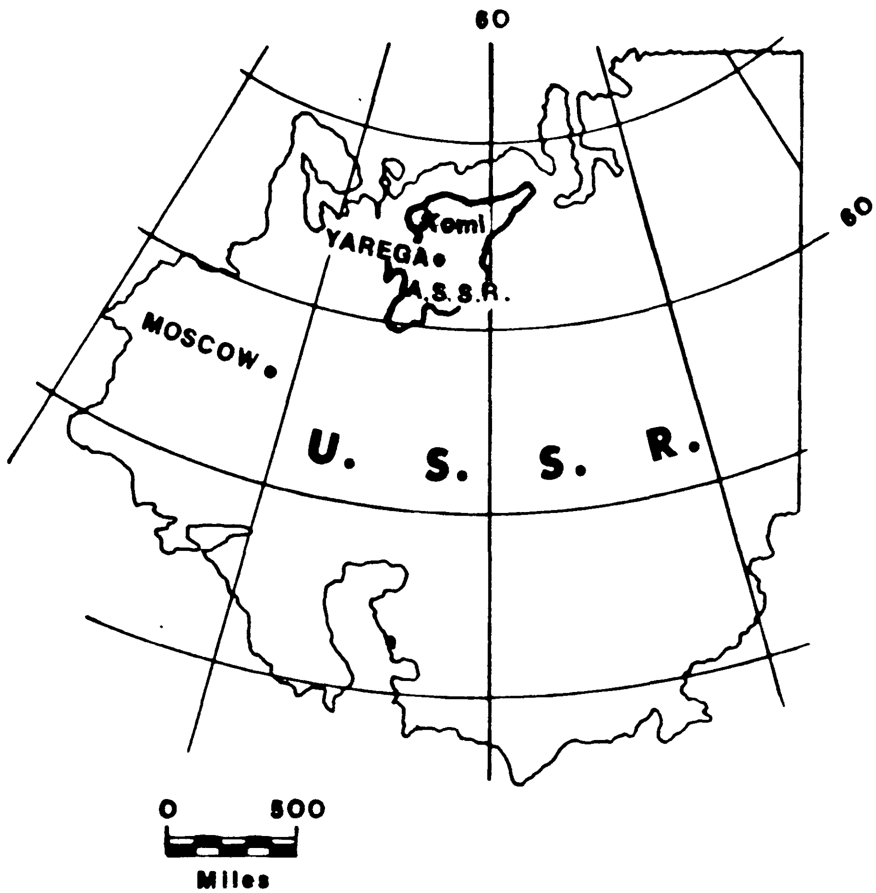


Figure 2.8

General Location Map (Yarega)

Source: Adapted from Ronald M. Brimhall, Thermally Assisted In situ Technique of Mining Oil, Society of Mining Engineers of AIME, New Orleans, February, 1979

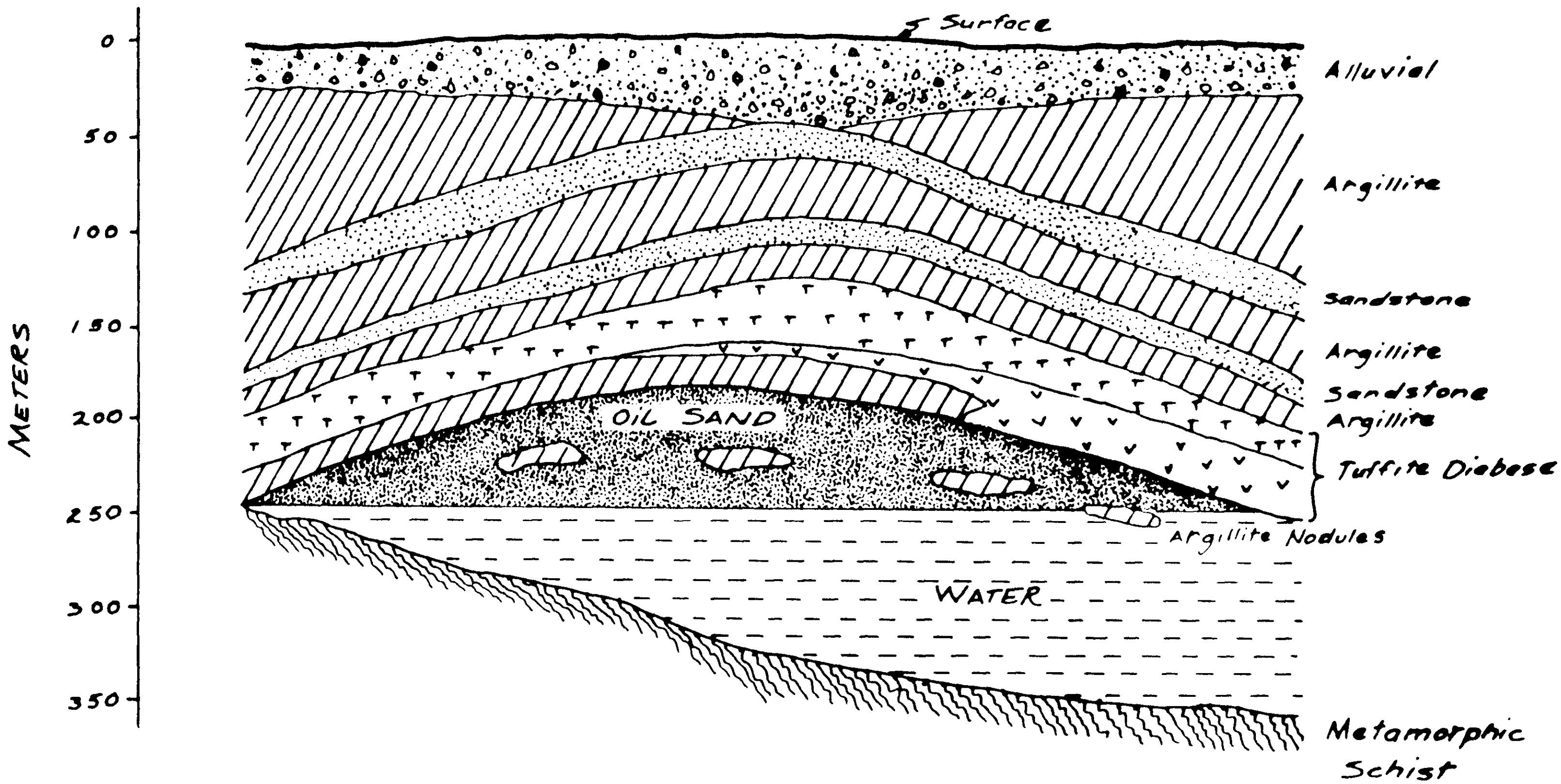


Figure 2.9

Geologic Cross Section of Yarega Oil Producing Region

Source: Recovery of Oil By Mining, Hearing Before the Subcommittee on Energy and Natural Resources, United States Senate, March 2, 1984 U.S. Government Printing Office, Washington, D. C.

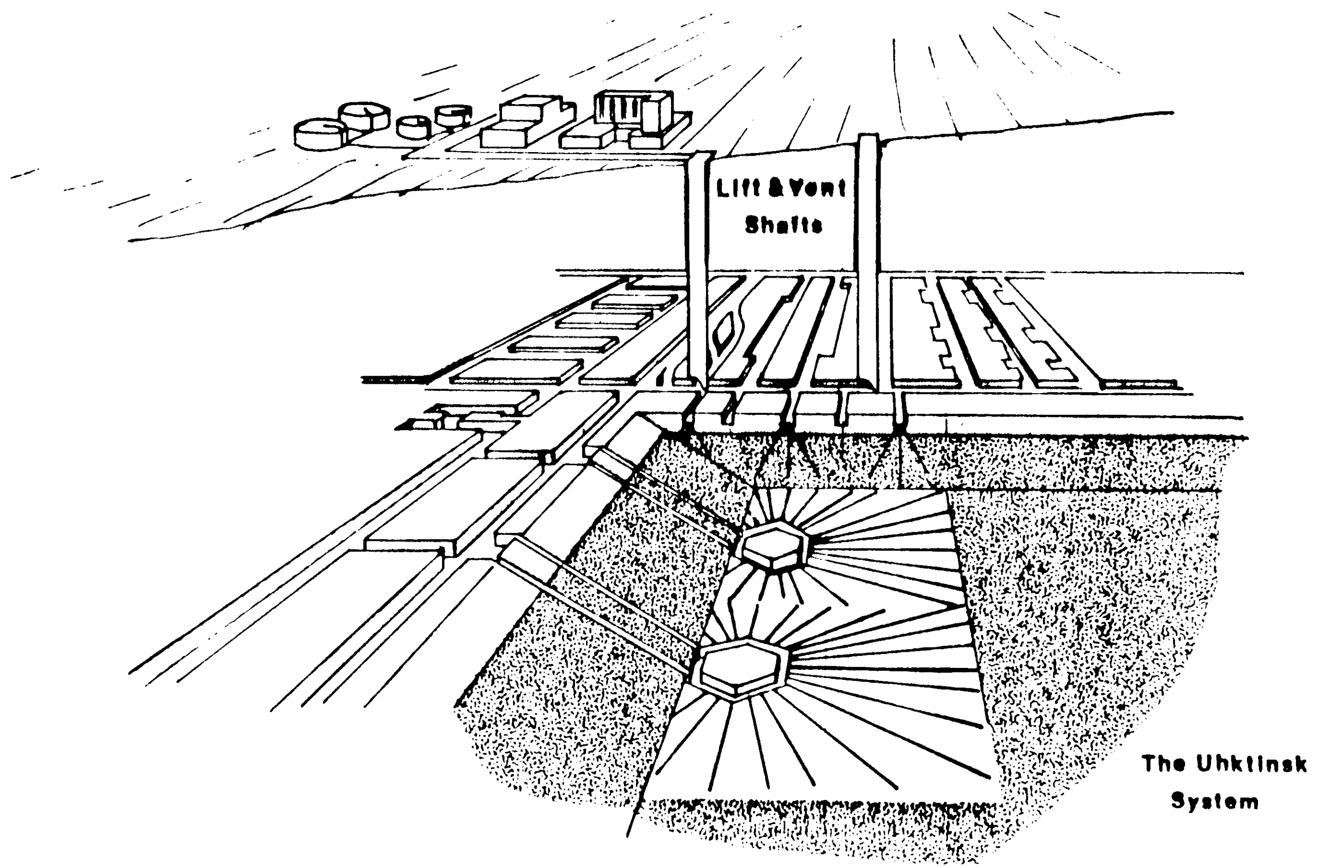


Figure 2.10

Schematic of Oil Producing Mine, Yarega, Komi A.S.S.R., U.S.S.R.

Source: Recovery of Oil By Mining, Hearing Before the Subcommittee on Energy and Natural Resources, United States Senate, March 2, 1984 U.S. Government Printing Office, Washington, D. C.

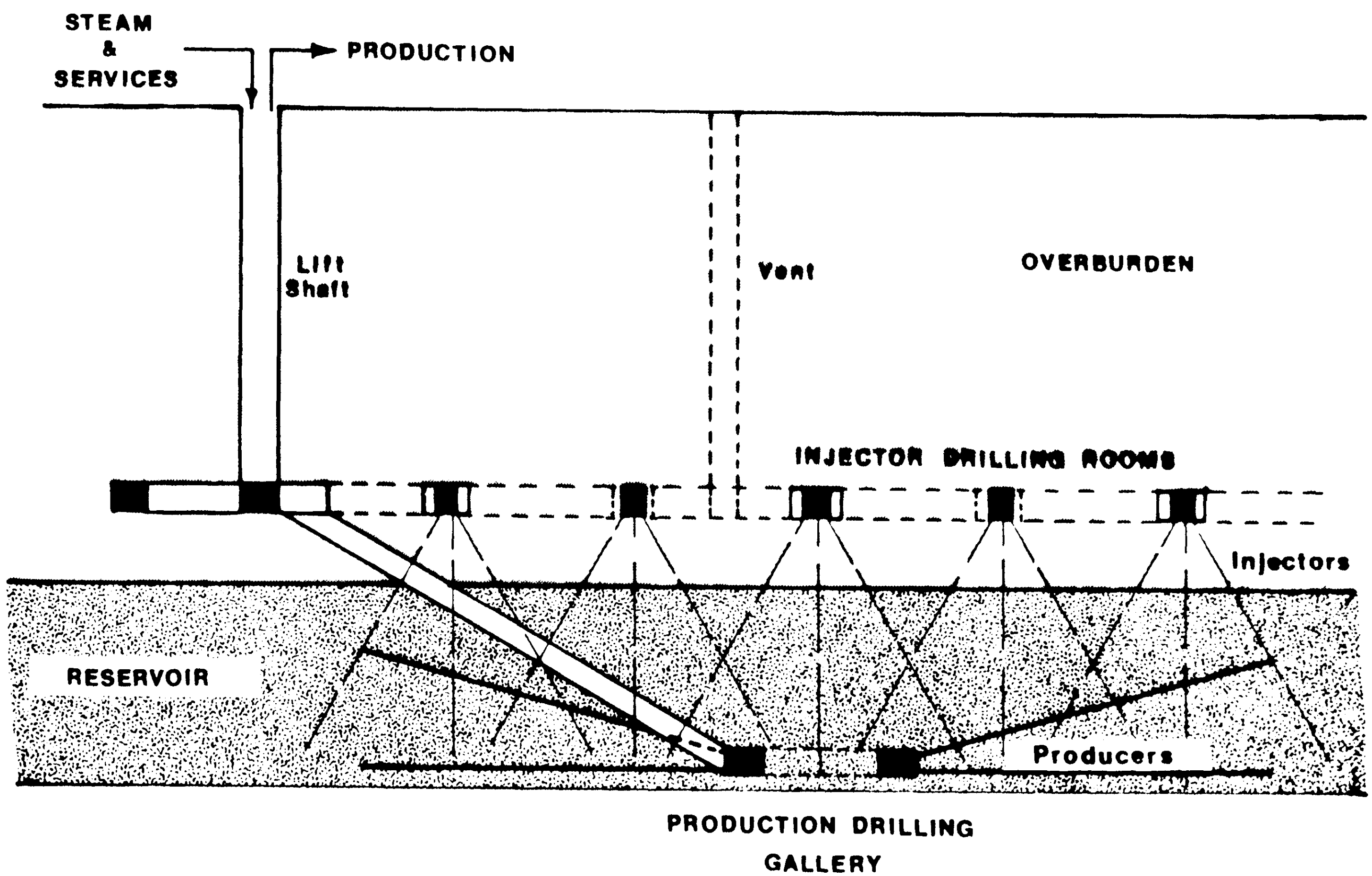


Figure 2.11

Soviet Thermal Mining Method

Source: Adapted from Ronald M. Brimhall, "Thermally Assisted In situ Technique of Mining Oil," Society of Mining Engineers of AIME, New Orleans, February, 1979

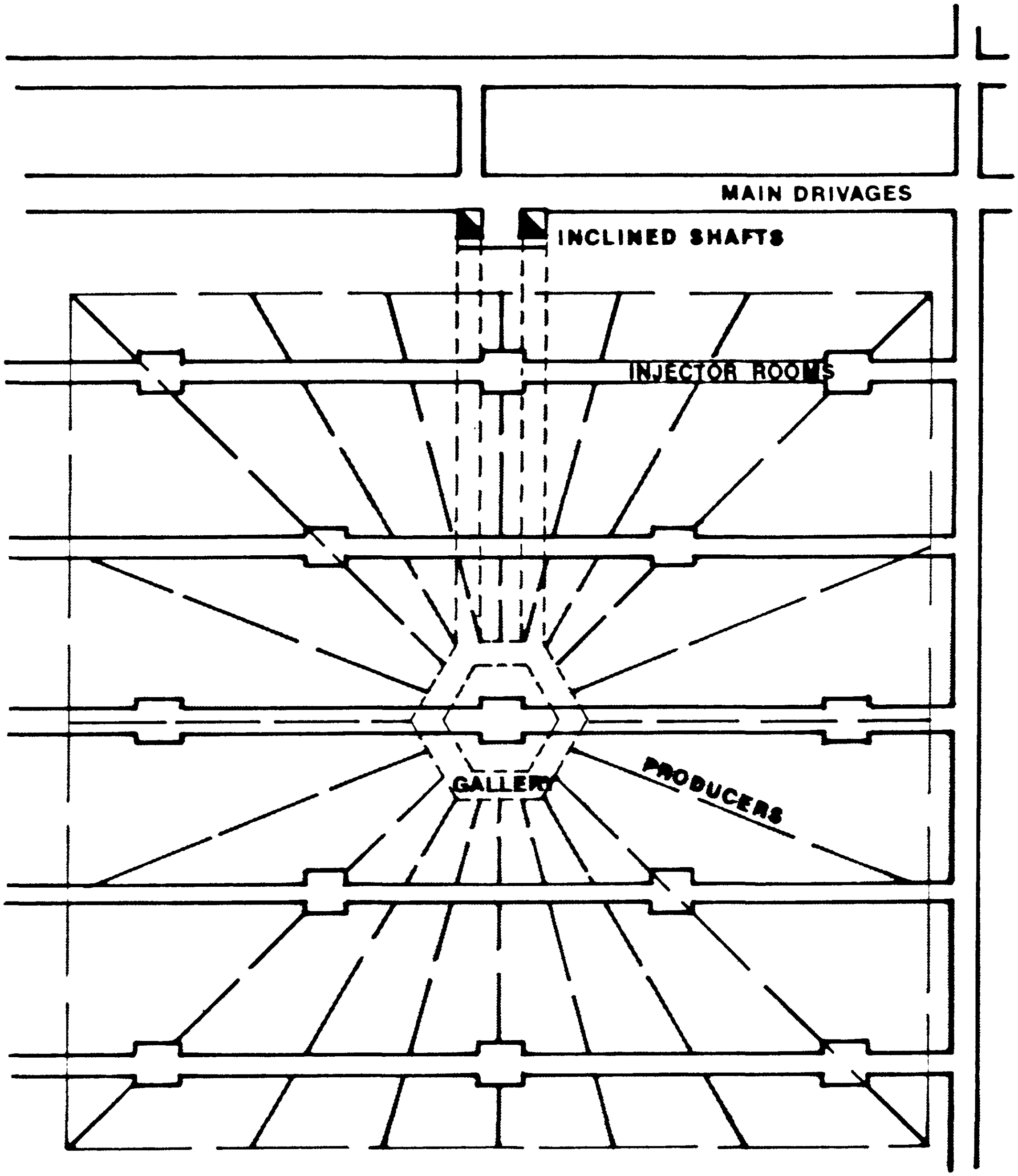


Figure 2.12

Soviet Thermal Mining Production Drilling Pattern

Source: Adapted from Ronald M. Brimhall, Thermally Assisted In situ Technique of Mining Oil, Society of Mining Engineers of AIME, New Orleans, February, 1979

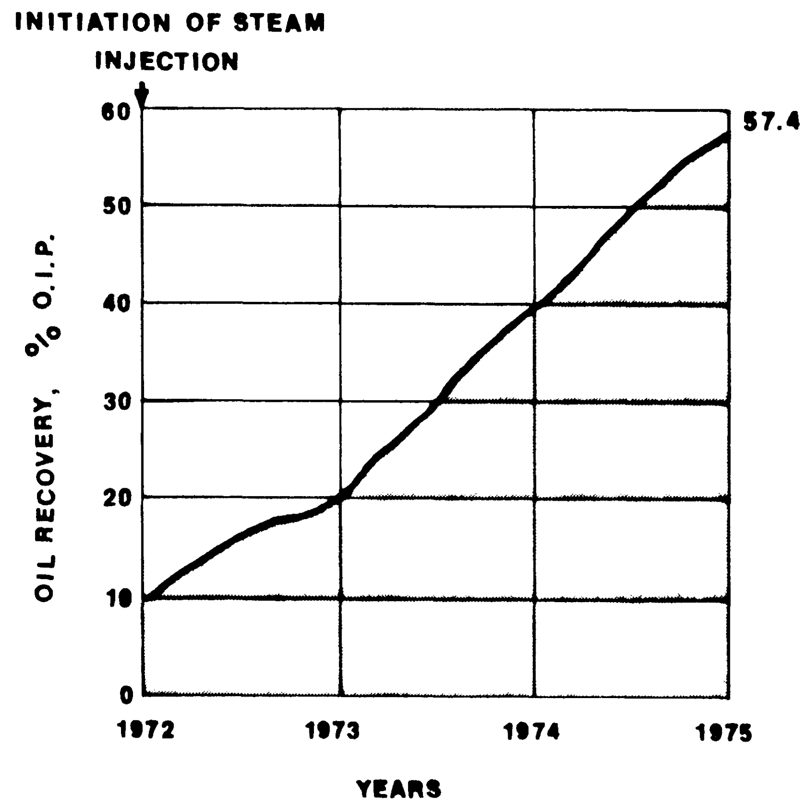
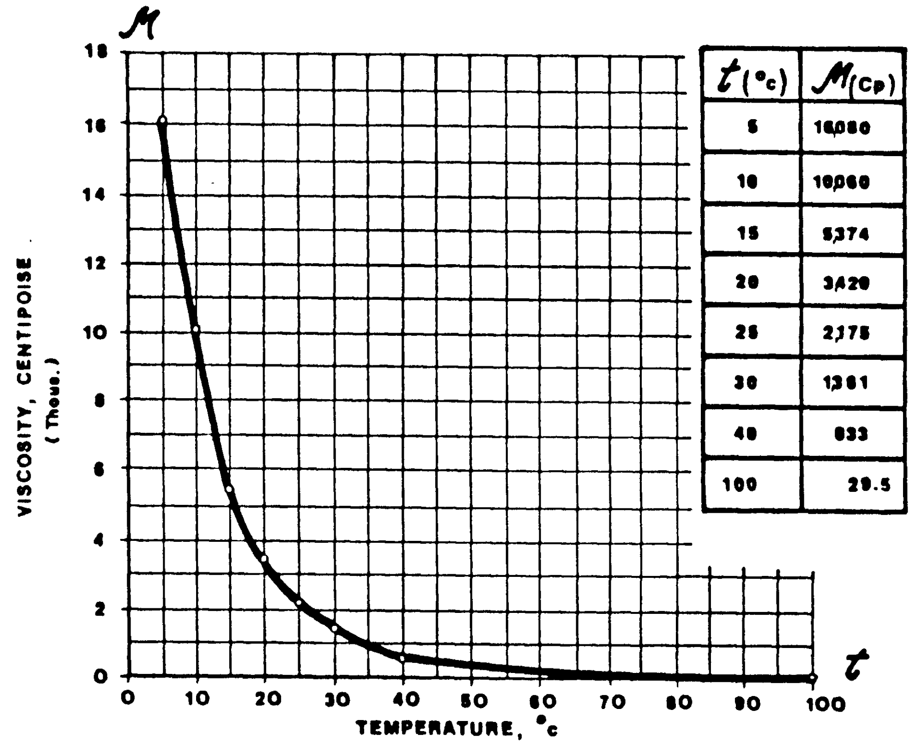


Figure 2.13

Oil Recovery For Oil Mine No. 1, Yarega, Komi A.S.S.R., U.S.S.R.
(Since Application of Thermal-Mining)

Source: Adapted from Ronald M. Brimhall, "<u>Thermally Assisted In situ Technique of Mining Oil</u>," Society of Mining Engineers of AIME, New Orleans, February, 1979



t (°c)	μ (cp)
5	16,080
10	10,060
15	5,374
20	3,420
25	2,175
30	1,361
40	833
100	29.5

Figure 2.14

Variation of Oil Viscosity With Temperature, Yarega Oil Producing Region

Source: Recovery of Oil By Mining, United States Senate, March 2, 1984 U.S. Government Printing Office, Washington, D.C.

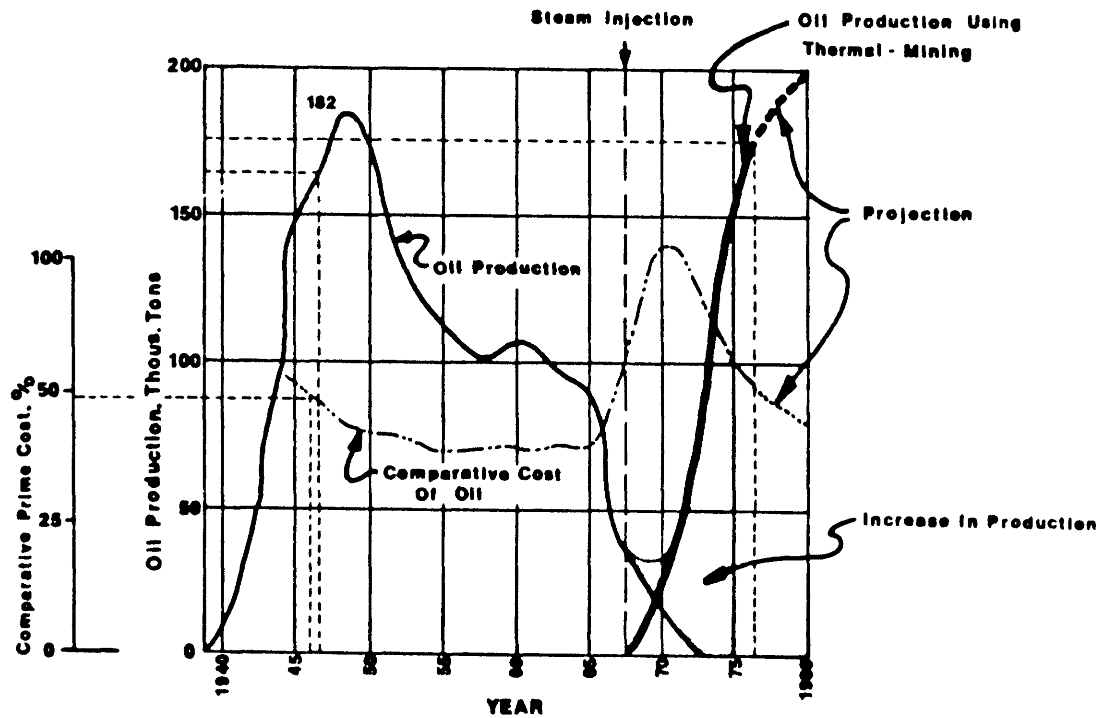


Figure 2.15

Production History For Mine No. 1 Yarega, Komi A.S.S.R., U.S.S.R.

Source: Ronald M. Brimhall, "<u>Thermally Assisted In situ Technique of Mining Oil</u>," <u>Society of Mining Engineers of AIME</u>, New Orleans, February, 1979

An aquifer which imparts no energy to the oil reservoir underlies the entire field. The natural energy for fluid movement is from fluid expansion and compression of the reservoir by the weight of the overburden.

Access to the reservoir and adjacent rock structures is made by conventional shaft mining techniques. Access drifts and main work areas are constructed in the tuffite diabase 18 to 30 meters above the reservoir. Access drifts to the hexagonally shaped production galleries are constructed from the main working level into the oil reservoir with a downward incline of about 15°. Production galleries are located near the bottom of the reservoir and contain about 250 production wells radiating outward and upward from 182 to 244 meters. The steam injection galleries are constructed at the main work level above the reservoir with the steam injection wells being drilled downward and outward into the reservoir and just above the production wells. Intense heating of the oil reservoir (93°C, 200°F) occurs in an area just above the production galleries. Produced oil and water are transported underground via open gutters, pumping substations, and pipelines to the central underground storage facility where the oil is separated from water and then pumped to the surface.

Bore holes for steam injection and liquid production are drilled with a drilling machine which uses a hydraulic turbine similar to a conventional power swivel. Energy to operate the rig is supplied by water presure from a pump station. The maximum drilling depth is 300 meters and the maximum hole diameter is 37 centimeters.

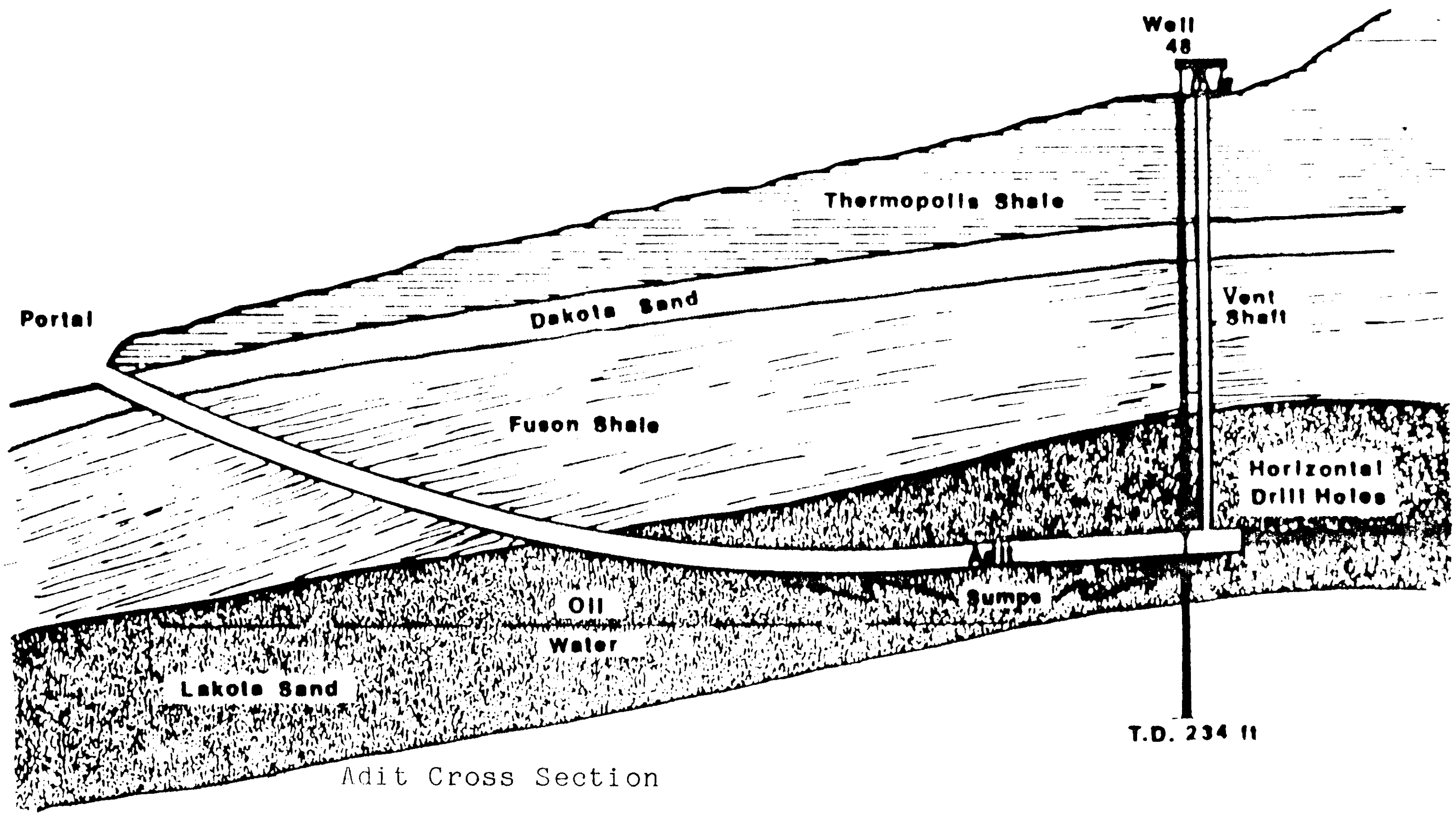
Normal production and injection wells are drilled with a 12 centimeter bit to a depth of 2.4 to 3 meters and then a 10-centimeter conductor pipe is installed which may be equipped with a blowout preventer. The drilling rig provides a safe working condition in a mine environment. Production wells are equipped with a master control valve after drilling operations are complete.

Generally, steam injection wells are drilled first and used as a producer to eliminate gas and reduce pressure. Only then are production galleries constructed and wells drilled. Sand control is obtained by the angle at which the production wells are drilled.

To initiate production, steam is injected into the wells on the upper level, thus heating the oil to reduce the viscosity and provide a pressure differential to move the oil to the production wells. Steam injection pressures are on the order of 75 to 120 psi, and injection rates are several pounds to four or five tons per hour per well. Specific steam consumption is about 6,600 pounds of steam per ton of oil (approximately 7 barrels of oil). Cyclical steam injection is used. Hot water and surfactants are recycled into the reservoir. Anticipated production for the three Yarega fields is 6,700,000 bbls. of oil per year. Development ratio is 85 bbls. per foot of development and six bbls. per foot of well drilled. Costs were reported at $5.29 per bbl. in April, 1976, with a capital expenditure of $8.8 million for a mine of 972,000 bbls. per year capacity.

The Conoco Mining Operation

In the United States, the first oil mining operation on a large scale was begun by Conoco Inc. in Wyoming in the North Tisdale field (Figure 2.16). Due to low reservoir energy pressures, it was estimated that only 2 percent of the oil could be recovered by primary methods. With the rising oil prices in the 1970s, the company began an oil mining operation which is described below. The North Tisdale field is located structurally on the asymmetric, north-plunging nose of the large Tisdale Mountain



Adit Cross Section

Figure 2.16

Conoco Oil Mine, North Tisdale Field, Wyoming

Source: W. F. Dobson and D. R. Seelye, "Mining Technology Assists Oil Recovery From Wyoming Fields," Journal of Petroleum Technology, February, 1982

Anticline. The Lakota structure generally parallels the surface topography of the mountain's crest and decreases in depth in the eroded draws where a number of outcrops are evident. The Lakota oil sands average a depth of 300 feet across the field with an average thickness of 58 feet. Some of its characteristics are:

Porosity	18.9%
Water saturation	40% to 50%
API Gravity of oil	28° API
Viscosity	19 cp at 70°F
Average Reservoir Temperature	60°F.

From the characteristics of the oil reservoir, a value of 733 bbl/acre-foot of original oil in place was estimated.

A vertical surface well was driven through the oil sands to verify the presence of the oil-saturated reservoir rock and to confirm the mine site. An adit was begun by conventional drilling, blasting, and mucking with the middle Lakota sands and the vertical well from the surface as the target. The instability of the shale above the oil reservoir required conventional timber supports for the adit. These were replaced with steel beams as the clays in the shale began to swell with the seasonal wet periods. When the adit reached a length of 720 feet, well within the competent upper Lakota sand roof, bolting and wire mesh replaced timbering. At a length of 985 feet, the adit intersected the vertical well.

Six horizontal drain holes were driven from the adit into the oil formation as close to the bottom of the oil saturated sand as possible. It was thought that this would take full advantage of the oil column height. The mine averaged 68 barrels of oil per day (BOPD) from August 1979 to August 1980, its first year of operation, and declined to 28 BOPD a year later. The operation of the mine has been turned over to the New Tech Mining Company which is planning to drill an array of vertical drain holes from the adit into the oil sands. The spacing and angles of these drain holes are proprietary. A steam assist is planned, at the time of the writing, though the oil was thought to be of low enough viscosity to drain through the reservoir.

Other known oil mining operations include Lawrence Allison, near Casper, Wyoming, on property owned by the Naval Oil Reserve. Here studies are underway to determine what type of mining operation is most suitable for the reservoirs involved. This operation is to be completely funded by the U.S. government.

The Heavy Oil Recovery Pilot Project at Kern River, California (HOPCO)

The Heavy Oil Recovery Pilot Project (HOPCO) at Kern River, California, (Figure 2.17) employs a method that can overcome the problems in driving a tunnel in incompetent rock under an oil reservoir. (Fuel and Mineral Resources, Inc., August 1984). This method uses a cavern, a 30-foot high cylinder reinforced with concrete, at the end of the shaft at a depth of 500 feet. From the cylinder at the base of shaft, a series of production drain holes are driven out into the formation in a hub or spoke pattern. Each lateral production hole serves alternately as an injector of steam and as a producer carrying a separate line for each function. The steam is generated at the surface and is injected into the sub-surface spool well-head at the base of the shaft and is distributed along the horizontal or lateral steam lines. The steam front percolates up, forms a gas cap at the top of the oil formation, and then drives down into the oil reservoir. Eight vertical steam injection wells which bisect the lateral injectors have also been installed. It was thought that a combination of horizontal and vertical steam injection holes would give maximum thermal efficiency. A feasibility study showed that the HOPCO method could achieve as

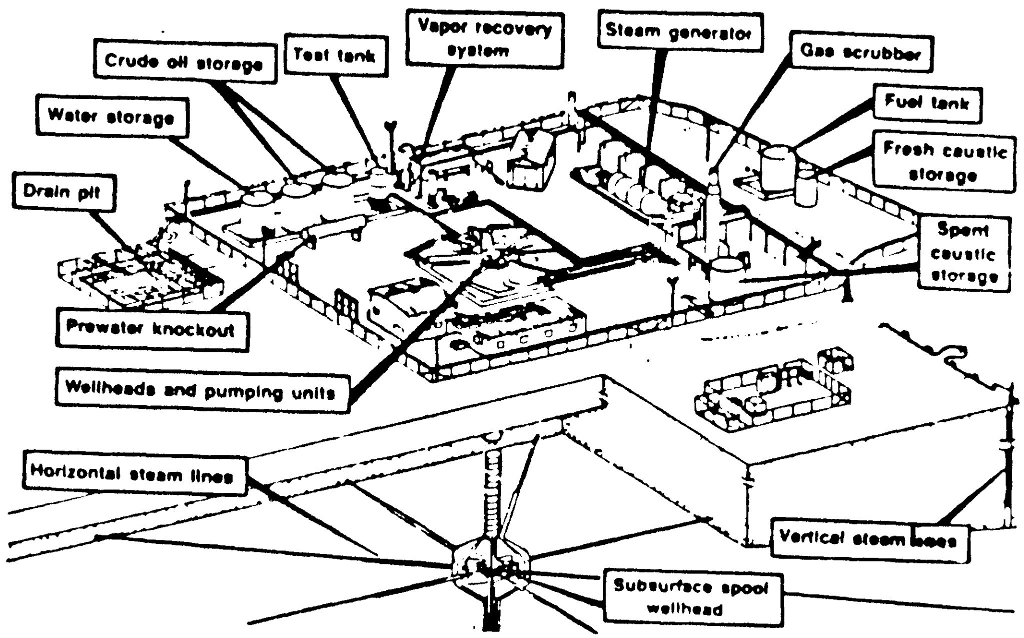


Figure 2.17

Layout for the Hopco Heavy Oil Recovery Pilot Project

Source: Ferioun A. Albayrak and Taho E. Protopapas, <u>Detailed Technical and Economic Feasibility of Light Oil Mining in the United States</u>, U.S. Department of Energy, Technical Information Center, Bartlesville, 1984 much as a 77% recovery of oil in place over a 6-year period. Production was at 300 BBL per day level in April, 1985. The mining method is supported by both the Department of Energy under the tertiary incentive revenue program, and by the Synthetic Fuel Corporation with a loan guarantee of $80 million toward the project's $125 million capital cost. Present economic conditions have resulted in a closing of this operation by the operator, the Ladd Petroleum Corp. of Denver, Colo. in April 1985.

Reservoir Targets for Oil Mining

Conventionally produced oil and gas is not a long term energy resource. The petroleum accumulations are limited. The declining ability of the United States to find and produce domestic oil when coupled with high rates of consumption of petroleum and natural gas are compelling reasons to contemplate the availability of this resource in the future. One method of increasing our production capabilities is to reach that portion of the resource now being unutilized by oil mining techniques.

Estimates vary as to the amount of oil remaining in place after extraction by conventional methods. The evidence is that significantly more than one-half of the oil originally estimated to be in place remains, and in many cases, it has been estimated that as much as two-thirds of the original oil in place remains after all recovery techniques have been applied. An American Petroleum Institute (API) study (Nehring with Van Driest, 1981) has indicated that for the United States as a whole, 67% of the original oil in place remains at the end of the economic recovery processes. The 100 largest oil fields that have been, or presently are, under conventional recovery production techniques were studied separately; it was estimated that 63% of the original oil in place will remain after full production. The total estimate of original oil in place remaining after conventional extraction methods is approximately 300 billion barrels. The API study broke down its estimate of oil left in place as follows:

Structural Traps	65.7%
Stratigraphic Traps	72.10%
Sandstone Reservoirs	66.32%
Carbonate Reservoirs	71.67%
Other Reservoirs	81.22%

The study further found that 85.7% of the unrecoverable resource is to be found in eight states, each with a residual resource of more than 10 million barrels. In order of decreasing estimated unrecoverable resources, these states are Texas, California, Oklahoma, Louisiana, Alaska, New Mexico, Kansas, and Wyoming.

Carbonate reservoirs are generally highly variable and can be evaluated only on an individual basis. Carbonate rocks are harder to drill. They tend to inhibit enhanced oil recovery techniques because injected fluids tend to carry carbonaceous material in solution and to deposit the same material elsewhere in the reservoir, reducing permeability. Dolomite is a better carbonate reservoir due to a higher porosity and a higher elastic modulus which results in more fracturing.

An oil reservoir with the simplest geological structure should result in the fewest problems for an oil mining operation. Those oil reservoirs that are folded and faulted in various ways, or that have steeply tilted beds, complicate the development of the mine and increase its cost. The hydrology of the reservoir area will also affect the mine plan. High ground water inflow into an underground opening may cause construction problems, delays, and increased costs necessary to install a dewatering system. When the mine is completed and is operating, the drainage holes will produce a certain amount of water with the oil. If the water is of poor quality, requiring disposal elsewhere, the costs will be increased.

The reasons for the lack of flow to the surface through a drilled well can be seen by examining Darcy's law for a linear system.

$$q = \frac{k\ A}{\mu} \quad \frac{d\ \phi}{d\ x}$$

where

k = permeability to oil,

μ = viscosity of the oil,

q = rate of flow,

ϕ = flow potential (sum of pressure and position potentials)

Basically, fields that have lost their contained natural pressures because of conventional recovery techniques, or have a highly viscous oil (low API gravity) or where the host rock is not permeable (i.e., chalk deposit) might be candidates for the oil mining by gravity drainage technique, with or without a steam assist, depending on the viscosity of the oil. Highly viscous oils need thermal assistance to enhance their flow characteristic, while less viscous oils (high API gravity) may drain through an array of production drill holes without thermal assist.

The natural pressures, or reservoir drive mechanisms, are solution gas drive, gas cap, and/or water drive. As recovery continues from a reservoir, fluid pressures decline, reducing the natural forces (or one of the above described mechanisms) that drive the petroleum fluid to the well bore and simultaneously forming a discrete gas phase that impedes fluid flow. It is at this point that secondary or tertiary recovery methods may be applied. Secondary recovery includes immiscible gas injection and water flooding. Tertiary recovery methods include steam injection, chemical flooding, or in situ combustion. After the application of primary and enhanced oil recovery techniques, up to 65% of the original oil in place remains. This remaining oil is the target for oil mining.

Three major factors in determining whether a reservoir is amenable to the oil mining by gravity drainage technique are: 1) the amount of original oil in place, 2) the depth of the reservoir, and 3) the competency of the rock below or above the reservoir. Information about rock competency below the reservoir is either scant or nonexistent. The petroleum industry usually obtains no data on the physical conditions below the oil reservoir. A speculative estimate as to the competency of the rock below the reservoir must be made from the nature of the lithology, the percentage of porosity and the permeability data. A limestone or dolomite with low porosity and permeability may be assumed to be competent. A reservoir with this lithology and a low porosity, but with a high fluid flow, even when measured core permeability is low, must be assumed to have many fractures and, therefore, its competency would be suspect. Sandstones and conglomerates with porosities greater than 30% and with high permeabilities can be assumed to be incompetent rock not strong enough to hold the mine works without supporting structures. Some fields, depending on the strength of the rock above the oil zone as compared to the rock below the oil zone, may be amenable only to gravity drainage from above the oil zone. The necessary parameters can be further defined as follows: (Recovery of Oil By Mining, 1984)

1) An oil saturation greater than 750 bbl/acre-feet with a net pay thickness of 10 feet or more, and sufficient mobility of the oil. A total of 10 million barrels of oil in place is a target.

$$\text{Mobility} = \frac{\text{Permeability to Oil}}{\text{Viscosity of Oil}}$$

2) A reservoir depth of no greater than 3,000 feet. The shallower the reservoir, the lower the mine vertical development costs will be, and the

faster the mine can be constructed. This implies more rapid production, and thus income can be generated more quickly. The shallower the reservoir, the lower the API gravity and generally the more viscous the oil.

3) The competency of the rock will affect the time of mine construction, the cost, and the safety of the mine works. The use of a tunnel-boring machine over the conventional drill-blast-muck method is a question of economics.

4) Since a steam thermal assist is considered necessary in many potential projects, a minimum overburden of 500 feet is considered necessary to employ this enhanced oil recovery technique so the heat generated will not be lost. A steam assist can add additional operational and capital costs of $12 to $14 a barrel to the mining operation. (EDC, 1983)

5) The seismic activity of the area must be considered, especially if the reservoir target is located in California.

The depleted fields in the basins of the Northeast contain 80% or more of their original oil in place (Indiana-Ohio Arch, Illinois and Appalachian Basins). During the late nineteenth and the twentieth centuries, these fields were rapidly developed. Drilling and production techniques were in their infancy. The natural reservoir energies of these fields were dissipated by uncontrolled drilling and the indiscriminate flaring of gas. The primitive plugging and abandonment techniques rendered many of these fields unsuitable for secondary recovery techniques because pressure could not be maintained in the reservoirs with injected water or gas. The net result is that the Northeast has numerous oil reservoirs with high oil saturations containing high API gravity oils that are of low viscosity. This implies a mining technique that may not need the additional expense of a thermal assist. Many of these fields are shallow, indicating that the cost of reaching the oil reservoir via a shaft and tunnel will be much less when compared to a deeper reservoir. Many of these older fields in the Northeast will have numerous title problems. The leases will be old, the assignments many, and the mineral interests may have been split or severed over the years.

On March 2, 1984, at the U.S. Congressional hearing on recovery of oil by mining before the subcommittee on Energy and Mineral Resources, a study by Lloyd E. Elkins, petroleum consultant, dated April 1980, was submitted for review. Potential reservoirs in the United States were examined with the following conclusions by Mr. Elkins.

1) The residual oil resource left after primary and secondary recovery in United States reservoirs amenable to mining or tertiary-aided mining recovery is estimated to be about 64 billion barrels located in some 94 different reservoirs.
2) Fifteen of the 54 reservoirs analyzed in the sample are rated good to superior for mining related recovery operations. The others are fair to poor. For the total U.S., the good or better prospects extrapolate to about 25 reservoirs containing 15 to 20 billion barrels of residual oil resource.
3) Based upon the ratings developed in Mr. Elkins's report, five reservoirs are identified as prime candidates for research and development of mining related processes. They are listed as follows:

		Resource (Billions Bbls)
Kern River, Calif.	- Excellent	3.5
Cymric, Calif.	- Superior	.18
Big Sandy, Kansas	- Good	.04
Caddo Pine, La.	- Excellent	.97
Healdton, Okla.	- Good	.35

4) Mining recovery processes are frequently referred to as "Drip Drainage" with demonstrated and quantifiable flow rate characteristics. Gravity head (effective height, i.e., continuous pay thickness), permeability to the oil phase, and area of the pressure sink are critical factors not easily quantified.

a) Bedding planes (very thin shale lamina) within a pay interval will serve as a no flow vertical barrier and may limit effective height.

b) Permeability to oil in a water-flooded, water-wet formation will be essentially zero; in oil-wet formations never zero, but low, depending on water flood intensity. Gravity drainage alone may be very slow or ineffective under these conditions.

c) Drainage area can be increased by design of mining processes.

The study further pointed out that

> most reservoirs having sustained natural or stimulated production in the United States will have oil, water, and often gas under pressure sufficient to cause problems if shafts (especially tunnels) are driven through them. Gravity drainage down dip in steeply dipping reservoirs where flow is parallel to "bedding planes" provides opportunity for very high recovery efficiency. Vertical drainage across bedding planes (even thin shale lamina) can be reduced to nil. However, if vertical joints are open and have permeability, oil moving laterally parallel to bedding planes can and will move downward by gravity to lower levels. But the oil still has to be displaced laterally out of matrix rock using energy and some type of displacement fluid.

This may explain why the horizontal wells at the Conoco project are not productive and why the present operator, New Tech Corp., is installing an array of vertical drain holes.

The essence of the hearing was to motivate Congress either to modify its tax structure or to lend financial aid of some kind to the fledgling companies attempting to initiate oil mining projects. The economics of 1985 do not permit raising capital in the public money market; some financial assistance, tax credits, or a restructuring of the tax code is essential.

CHAPTER 3

ENVIRONMENTAL ASPECTS

The growth of environmental law has been phenomenal since 1970. For that reason, it is important to note at the outset that the environmental impact of oil mining by gravity drainage seems to be minimal when compared with other mining techniques or with industrial activity designed to produce synthetic fuels. The economic benefits to be gained by gravity drainage far outweigh the slight surface disturbances that occur as a result of the excavations necessary for the construction of the shafts and tunnels, and the support facilities for the underground workings. The waste material from the excavations is stored and then disposed of on-site at the surface. A chemical analysis of the waste material determines how these spoils should be handled. The effect of the waste on the air, water, and local esthetics must be considered in any plan devised for its disposal. Its physical stability should withstand gravity and earthquakes; this implies permanence. Therefore, wastes must blend into and become part of the landscape in as natural a manner as possible within a economically realistic framework. The spoil pile should be stabilized against air and water erosion. This is usually done by revegetation with local flora and by using the topsoil saved from both the site of the surface of the disposal area and from the excavations. Using the local topsoil should stimulate plant growth compatible with and related to the local ecosystem, providing a beneficial esthetic effect.

Mine wastes sometimes contain toxic or other hazardous substances that oxidize or leach into the groundwater, are taken up by the surrounding plants and, in turn, poison local grazing animals. This is why a chemical analysis should be made of mine spoil prior to the formulation of a plan on how the spoils are to be disposed of. A chemical analysis of the runoff from the stockpile should also be made to indicate whether the water has to be treated before being allowed to return to the local ecosystem.

We have mentioned that esthetics in a mine development is an important factor. In this operation, any headframe remaining over the shaft as a permanent installation can be made to look like an agricultural building, or anything else for that matter, by covering the skeletal frames. Tourists or passersby on the highway will probably never know that an oil mining project exists at that location.

The National Environmental Policy Act (NEPA)(42 U.S.C. Sec. 4321, 4331-4335, 4341-4347; 1969) requires a detailed environmental impact statement of a proposed major activity if that activity will significantly affect the quality of the human environment. This legislation requires that environmental values be considered in any government agency decision-making process, and that these values must be balanced against the economic benefits as well as any alternative procedures. This procedure focuses attention on the issues and allows prior public input. In this environmental impact statement many of the concerns alluded to here will be raised and procedures will be adopted to solve them in the best possible manner. NEPA is a balancing statute; no activity is banned under this statute. It merely requires that environmental values must be considered and balanced with the economic benefits of the proposed action. This is done with the required environmental impact statement as the focusing medium.

The use of a generating plant and boiler for a steam or thermal assist in order to reduce oil viscosity and increase its flow rate may require a dispersion analysis in order that air quality is maintained pursuant to federal and state regulations. The Clean Air Act (42 U.S.C.

Sec. 7401 et seq.; 1963) vests the head of the Environmental Protection Agency with control over this area. Quality standards for ambient air have been established by the EPA. These standards govern emission limitations for nonmoving, "stationary" sources, such as power plants or factories, as well as for moving sources such as automobiles. The main thrust of the stationary source emission standards is on "new" stationary sources, including oil mining.

The pollutants regulated are particulate matter, sulfur oxides, carbon monoxides, nitrogen dioxide, ozone, hydrocarbons, and lead. Although the federal government has set the air quality standards, each state has the opportunity to implement them as they see fit. The stationary source emission standard that will be permitted should be a product of the balancing of the environment with the economic factors. The available control technology and the cost of such technology must be taken into account in any decisions concerning the emissions of pollutants into the atmosphere.

The Clean Water Act (33 U.S.C.S. Sec. 1251 et seq.; 1972) leans very strongly toward pollution control by limiting the discharge of effluents as opposed to the Clean Air Act which makes substantial use of the ambient air quality standards with state implementation to achieve them. Discharges of effluents are allowed only if they are in compliance with the effluent limitations, and only by obtaining a permit to discharge within those limits. Permits are issued by the states to discharge effluents if they have an EPA-approved plan with limitations at least as strict as those of the EPA. Congress has included heat within the definition of a pollutant under the Clean Water Act. Thus, water quality control measures governing effluent limitations include thermal discharge standards. These will have to be considered should the mine plan have a steam assist. The effluent limitations require the application of the "best conventional pollutant control technology" (BCT) available before a permit will be issued, allowing the effluent discharge.

Any groundwater encountered when sinking shafts is to be treated as the existing state regulations require in order to protect water quality. It probably will be discharged to a surface water body or reinjected into the ground.

Overall, the environmental impact in connection with an oil mining by gravity drainage operation seems to be minimal compared with other methods.

CHAPTER 4

ECONOMIC CONSIDERATIONS

Introduction

The previous chapters indicate that future additional domestic oil production can come from known oil fields. Methods of extracting the presently unreachable two-thirds of the oil resources left after all conventional recovery techniques have been applied must be developed. Oil mining by gravity drainage is one method to reach the oil that is being left in the ground. Russia's project at Yarega, as well as those in France and Germany (Appendix C and D), indicate that this technique is technically feasible. The question then presents itself, is it economic under our system? This chapter will try to analyze some of the financial considerations in a sensitivity analysis from a base case selected as the most likely situation. This case is detailed in the next section of the chapter. To reflect some uncertainties in parameters, as used in the base case a sensitivity analysis was applied. In the 19 sensitivity analyses performed (on program ECON, Colorado School of Mines Computing Center) the key economic variables were varied to gauge their effect on the financial outcome of the project under examination. The analysis was made in constant 1985 dollars. We must rely on the soundness of the engineering cost estimates and accept the fact that, since they are based upon an untried mining technique, they are subject to some estimating error.

Case Study

The northeast McKittrick Field, Kern County, California consisting of 744 acres, was selected by Energy Development Consultants (1981) for development by gravity drainage with a thermal assist. This property was previously exploited using conventional recovery methods and data were available as to the specific characteristics of the reservoir. The author used data from this field because it concerns a reservoir with a steam assist and is from a recent feasibility study (EDC, 1983). The data indicate a heavy oil reservoir with an API oil gravity range of 11^{o}-17^{o}. A steam assist is necessary to lower the viscosity of the oil so that it may flow through the reservoir and into the drainage holes. The recovery of oil is inversely related to its viscosity (EDC, 1983). The reservoir is amenable to the oil mining technique due to its relatively shallow depth of 400 feet to 1200 feet, its large proven resources, and the thick net pay of the reservoir. The main producing zones, the Olig member and the Tulare, have high permeability and porosity. The oil in place, after primary recovery and before a gravity drainage operation, was calculated using the standard formula:

$$N = \frac{(7758)\ A\ h\ \phi\ (1-S_{wi})}{B_o}$$

where

A = the producing area of 743.8 acres

h = 84 ft height of the oil column

ϕ = porosity, 35%

S_{wi} = initial water saturation (37%)

$(1-S_{wi})$ = So = initial oil saturation (63%)

B_o = Oil Formation Volume Factor (1.05 $\frac{RB}{STB}$)

N = oil in place, Stock Tank Barrels (STB)

$$N = \frac{(7758)\ (743.8)\ (84)\ (.35)\ (.63)}{1.05} = 101{,}800{,}000$$

These 101,800,000 barrels of oil are estimated to be in place after primary recovery and before the application of the gravity drainage technique. Of this potential target, 50% was estimated to be recoverable over an 8-year period (about 50,000,000 barrels) by using an energy intensive steam drive in this heavy oil reservoir (Lewin, 1981; EDC, 1983).

In order to calculate flow rates in a gravity drainage operation without a steam assist, the following equation (EDC, 1983) was used:

$$Q = (7.1659 \times 10^{-4}) \frac{k_o \quad h^2 G_o \ (y^2 - x^2)}{\mu_o \quad \ln(.472 \ \frac{r_e}{r_w})}$$

where

- Q = the rate of flow of the oil from the drainage slot in Ft^3 per hour
- K_o = permeability in millidarcys (md)
- μ_o = viscosity in centipoise (cp)
- h = height of the oil column from the drainage zone in feet
- G_o = the specific gravity of the oil
- y = fractional height of the oil column at the maximum drainage radius
- x = fractional oil column height at the bore hole
- re = well spacing radius of influence (1/2 of well spacing) in feet
- rw = the radius of the well bore in feet

The calculated flow rate was then modified for the application of the high energy steam drive to the reservoir. This model determines oil recovery as a function of steam injection, steam zone growth, heat balance equations, and key reservoir characteristics (Lewin, 1981; EDC, 1983). The recovery of the oil in place, and the rate of flow can be expressed in the simplified form

$$Q = f\ (\text{steam, reservoir characteristics}).$$

Energy Development Consultants, in their 1983 study, arrived at the following flow rates for a 50% recovery of oil in place. The rates of production for their steam model were adopted from the results of several steam drive operations in California's heavy oil fields and were incorporated into the base case. They assumed that the field would be developed with 40 production patterns.

	% of Total Recovery	50% of Total Recovered (BBLS)	One 9-Spot Production Pattern (BBLS)
Year 1	7%	3,562,645	89,066
Year 2	11%	5,598,442	139,961
Year 3	15%	7,634,240	190,856
Year 4	15%	7,634,240	190,856
Year 5	15%	7,634,240	190,856
Year 6	13%	6,616,341	165,409
Year 7	13%	6,616,341	165,409
Year 8	11%	5,598,442	139,961
Totals	100%	50,894,931	1,272,374

An analysis of the per barrel cost of obtaining the oil from this one 9-spot pattern over the 8-year operating life at a crude oil price of $26 per barrel is presented in Table 4.1

For tax purposes, 70% of the capital cost was taken as mine development and was expensed for tax purposes in the first operating year. The 70% figure is a typical number for an underground mining operation. (Berry, 1985) The remaining 30% was depreciable capital, with the assumption that 80% of it was eligible for the 10% Investment Tax Credit.

The entire operation consists of 40 9-spot pattern configurations. The steam injector is the ninth spot located in the center of each of the 40 patterns. The area serviced is approximately 18.5 acres for one pattern. The other eight slots are gravity drainage holes which surround the centrally located steam injector. The eight slots are drilled in a slight upward direction from a production gallery in the tunnel beneath the formation. Capital costs of the mine workings, with a 300 ft drain hole spacing, 360 holes in total, was estimated at $126,565,000, with an additional $40,280,000 calculated to represent the cost of the steam injection facilities (EDC, 1983). To this total of $166,845,000, a 10% contingency

TABLE 4.1

Costs Per Barrel of Oil at $26 Price (Base Case)

#2 Fuel Oil at $.80/gal		$12.08	(15.10 gal fuel oil used bbl oil)
Non-steam Operating Costs		$ 1.98	($315Kx8)/1,272K bbl
Gross Capital Costs	$3.61		($4,590K)/1,272K bbl
Less Tax Credits	$1.25		($1,590K)/1,272K bbl
		$ 2.36	($3,000K)/1,272K bbl
Royalty		$ 3.25	(12.5%x$26 bbl)
Finding Costs		$ 0	
Total Costs Per bbl Before Federal Income Tax & Interest		$19.67	
Interest at 15%		$ 1.85	(669*x8-3,000K) 1,272K bbl
Income Tax at 23%***		1.03	
Gross Total Cost		$22.55	

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* A = P x factor = $3000x0.22285** = $669/yr.

Tax Credit = 8% x 30% x $4.59M + 46% x 70% x $4.59M
= $.11M + $1.48M = $1.59M

Net Capital = $4.59M - $1.59M = $3.00M

** $A/P_{15\%,8}$ (Stermole, 1982)

***Full tax rate = 46%; with Percentage Depletion Allowance, Effective Tax Rate = 23%.

Income Tax = 23% ($26-$19.67-$1.85) = $1.03

K = in 1,000 = 10^3

M = in 1,000,000 = 10^6

was allowed ($16,684,500) for a total mine construction capital cost for the 40 producing patterns of $183,529,500 or $4,588,238 for one 9-spot pattern. This one production pattern with a $4.59 million cost is used for the base case.

Annual 1983 operating costs for this one pattern were estimated at $2,539,700 (EDC, 1983) with 88% of this cost attributable to the purchase of 2.4 million gallons of #2 fuel oil. The fuel oil is used to generate the 70% quality steam at 600 psi from a portable skid-mounted steam generator on the surface. (.072 x $.925/gallon x 42 gallon 2,179 bbls/day x 365 days) = $2,224,700 as the basic fuel cost to which is added $315,000 in incidental fixed annual steam generating costs to reach the total yearly operating costs of $2,539,700 (EDC, 1983). [The coefficient (.072) is derived from the BTU requirements to generate 1 barrel of steam. (Lewin, 1981)] The total cost of generating the steam was reduced to $1,920,000 for the base case due to the drop in the price of #2 fuel oil since 1983 from $.925/gallon to $.80/gallon in 1985; this #2 fuel oil price is used in the base case when the crude oil price is $26 per barrel.

The yearly operating cost in 1985 dollars for one production pattern is $2,235,000; this is equal to $89,400,000 for the 40 patterns. Over an 8-year operating life the total costs would be $715,200,000 to produce 50,894,931 barrels of oil. This is equal to an operating cost of $14.06 per barrel of oil produced at the 50% recovery level. Should the recovery level drop to 40%, the operating cost per barrel of oil climbs to $17.57. If the recovery level drops from 50% to 40%, annual oil production drops by 20%; yet the annual operating costs remain the same. Likewise, if recovery increases to 60%, operating cost per barrel decreases to $11.72 per barrel of oil. The average annual production rate at the 50% recovery level is 6.25 million barrels over the 8 years for the 40 pattern operation. If the recovery level drops to 40% the average annual production rate falls to 5.00 million barrels. The annual steam generating costs remain constant and are spread over less barrels of production if recovery drops, causing a sharp rise in the operating cost of each barrel of oil produced. An increase in the price of oil will not represent a pure increase in profits for an oil mining operation as the price of #2 fuel oil used to generate the steam drive will also increase, causing the operating costs to go up, absorbing part of the additional revenue. Likewise, a decrease in the price of crude oil will be partially offset by a decrease in the price of #2 fuel oil. It is assumed that the price of #2 fuel oil changes linearly with a change in the price of crude oil. For example, if the price of crude oil drops from $26 to $22 per barrel, the price of #2 fuel oil will drop from 80 cents to 67.7 cents per gallon, resulting in the cost of #2 fuel oil per barrel of crude to drop from $12.08 to $10.22, a difference of $1.86.

If we use 88% of total operating costs as a rough rule of thumb guide for the cost of producing the steam, we arrive at $1,966,800 (2,235,000 x .88) as the cost of steam production for one production pattern. Using $.80 as a cost of one gallon of #2 fuel oil per production pattern per year, over an 8 year operating life this equals 19,668,000 gallons of No. 2 fuel oil consumed to produce 1,272,000 barrels of oil from the reservoir, which is equivalent to burning 15.46 gallons of #2 fuel oil in order to produce one barrel of oil from the reservoir. Using $.80 as a cost, we arrive at a steam generating cost per barrel of oil production of $12.37 (15.46 x $.80). The non-fuel costs of $2,520,000 ($315,000 x 8) add an additional $1.98 to the cost of a barrel of oil. Total cost of each barrel of oil produced is $14.35 (12.37 + 1.98).

Since approximately $14 is spent to obtain 1 barrel of product worth $26, it costs $.55 to get $1 of gross revenue.

Financial Results

A base case for the sensitivity analysis was adopted with the following parameters included: a 15% depletion allowance for tax purposes, accelerated depreciation, no state severance tax; a crude oil price of $26, no windfall profits tax, a 50% recovery of oil in place over an 8-year operating life, 70% of the $4.59M capital costs are treated as development and are expensed for tax purposes in the first year, a 10% investment tax credit on 80% of 30% of the capital costs, a 12.5% royalty payment, and an $.80 #2 fuel cost per gallon to generate the steam. No front end bonus was assumed, there was no working capital requirement and no minimum tax in this base case. These parameters were selected for the base case as the 15% depletion allowance is available to oil shale producers and oil mining should be treated similar to oil shale for tax purposes. The state of Wyoming has waived the 5% severance tax for oil mining projects and the assumption has been made that the state of California would do the same. The crude oil price of $26 is the present 1985 price which will vary in the market place and over which an oil mine operator has no control. Tier 3 oil producers (those in the Enhanced Oil Recovery category) generally are not subject to the windfall profits tax at an oil price of $26 as presently calculated. The 50% of oil in place recovery over an 8-year period is based upon steam assist operations in California's heavy oil reservoirs and the $.80 #2 fuel oil price has been selected as an average price when oil is at $26 per barrel. The base case royalty of 12.5% of the wellhead price of crude oil is based upon the EDC, 1983, feasibility study on the McKitrick Field; this is the standard 1/8 royalty in the petroleum industry. For income tax purposes, it was assumed that the operator could take full advantage of the investment tax credit and was able to expense the mine development costs against income from other sources so as to benefit from this allowable tax write-off. These variables seem to justify the base case as being the most likely scenario. For the sensitivity analysis we varied the crude oil price, and the percentage of oil that could be recovered from the reservoir, as well as the length of time it would take to recover this amount of oil. The capital and operating costs were varied by a plus and minus 25% in order to assess their sensitivity to the change. Royalty rates were varied from 12.5% to 6.25% and then to 0%. The depreciation was varied along with the 15% depletion allowance and other tax parameters. The results of 19 different financial runs (all assuming 100% equity financing) are given in Table 4.2. We found that the base case DCFROR equals 27.9% and that the percentage recovery of oil in place is the most critical factor affecting the DCFROR. Should this recovery increase from 50% to 60%, the DCFROR would increase from 27.9% to 42.5%. Also, operating life is very important to the financial results. When operating life was reduced from 8 years to 6 years, resulting in higher production per year for the same operating and capital costs, the DCFROR went from 27.9% to 40.5%. Both a 60% recovery and a 6-year operating life appear possible based upon the reported experience at Russia's Yarega Oil Mining Project where 47.4% recovery of oil in place was obtained over a 3-year period with the steam assist. (see Figure 2.13) On the other hand if the recovery level of oil in place dropped to 40%, or the recovery is produced over a 10-year operating span, the DCFROR falls below 15%. If the oil mine operator owned the entire fee, and thus 100% of the mineral interests, there would be no royalty expense. The DCFROR would climb to 38.6% from 29.7%. If there is a mineral lease and a royalty of 6.25% can be

TABLE 4.2

Sensitivity Analysis: 19 Different Computer Runs

	Sensitivity Run	% Recovery of Oil in Place	#2 Fuel Oil Price/gal	DCFROR After Tax
1.	Base Case	50	$.80	27.9%
2.	Base Case	40	.80	9.7
3.	Base Case	60	.80	42.5
4.	Base Case	30	.80	Negative
5.	Straight Line Depreciation	50	.80	27.2
6.	No Depletion Allowance	50	.80	20.6
7.	With a 5% Severance Tax	50	.80	24.1
8.	$18 Oil Price	50	.55	15.1
9.	$22 Oil Price	50	.677	21.9
10.	$30 Oil Price	50	.923	33.4
11.	With a Windfall Profits Tax	50	.80	25.8
12.	Royalty at 0%	50	.80	38.6
13.	Royalty at	50	.80	32.9
14.	Capital Cost plus 25%	50	.80	21.6
15.	Capital Costs minus 25%	50	.80	39.2
16.	Operating Costs plus 25%	50	.80	14.8
17.	Operating Costs minus 25%	50	.80	39.4
18.	Production Over 10-Year Life	50	.80	12.7
19.	Production Over 6-Year Life	50	.80	40.5

negotiated, the DCFROR would go from 27.9% to 32.9%. In most mining leases, the royalty rate as a percentage of revenue seldom exceeds 7%. (Berry, 1985)

If we assume that the risks involved in applying this undeveloped technology to uncertain conditions calls for a hurdle rate of 15% as a minimum return, we find that this condition is met in all of the sensitivity runs except where the percentage recovery of oil in place falls from an expected 50% to 40% level or the production is recovered over 10 years as opposed to an 8 year operating life. Where the operating costs increase 25% above the base case costs of $2,235,000, the DCFROR falls to 14.8%, or still relatively close to our hurdle rate. A decline in the price of oil from $26 to $18 per barrel does not affect the DCFROR as strongly as the non-price variables.

It should be pointed out that the $4.59 million capital cost of each 9-spot producing pattern was arrived at by dividing 40, the total number of patterns, into the total estimated capital cost. Should a pilot project be financed by the U.S. government, the capital costs would exceed this $4.59 million as there would be fewer drainage patterns and thus less oil production to adsorb the high cost of driving the shaft and tunnels. In order to avoid the large front end capital costs of developing the mine workings, any oil mine presently being operated might be used for the development of the steam assist in the drainage process. This would save a considerable sum of money.

The oil mining technique was not considered when present hydrocarbon legislation, such as the windfall profits tax, was passed, nor is the technique defined by statute which makes interpretation of where it fits in the tax or regulatory scheme almost impossible. Clarification is necessary so that oil mining receives equal treatment as a tertiary recovery method and the financial incentives necessary for the industry to develop oil mining. Because of the statute's lack of clarity, oil mining could possibly be taxed at the highest windfall profits tax rate instead of at a lower rate at which, by law, the enhanced oil recovery and tertiary methods are taxed. These secondary recovery methods are not as capital intensive as oil mining. This results in an inequitable construction of the tax law that was probably never intended. A lower windfall profits tax rate was given to tertiary recovery techniques because of the technical problems that must be overcome when these methods are used and also presumably to encourage development in this area. The author firmly believes that tax treatment of oil mining should be equitable with other enhanced recovery methods because it is in fact an enhanced recovery method.

A further analysis using the base case, one of the most likely situations, indicates a payback period of 2.4 years for this one 9-spot pattern as follows:

Net Capital Investment equals $3,000,000 (see Table 4.1)

Net Cash Flows after Taxes of

Year 1	$1,570,032
Year 2	$ 800,558
Year 3	$1,570,504
Year 4	$ 648,906

The payback method is fast and simple to calculate but is considered a poor economic evaluator as the time value of money is not explicitly considered and the method does not consider the cash flows beyond the payout period or over the project life. (Berry, 1972) It is a handy screening device. Companies needing a payout of less than three years as a minimum requirement may consider further analysis since this requirement is met.

The base case has a DCFROR of 27.9%. Since this is substantially above the hurdle rate of 15%, it is accepted as a satisfactory rate of return (ROR) for the risks involved in this oil mining project. The decision therefore would be to pursue the project. This assumes that 50% of the oil in place is recovered at a price of $26 per barrel of oil. Even if the oil price falls to $22 per barrel of oil the rate of recovery of oil in place remains at 50%, the DCFROR is 21.9%. An $18 oil price yields a DCFROR of 15.1% which is still acceptable by the financial standard we have chosen.

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

In 1985 the oil surplus and the soft oil prices prevented a small untried company from raising the large capital sums necessary to finance a commercial oil mining project in the United States. (Recovery of Oil By Mining, March, 1984)

United States consumption of oil has dropped from 18.8 million barrels a day in 1978 to 15.2 million barrels a day in 1983 (Albracht, 1984) because of the price elasticity of demand. To further illustrate the continued decline in consumption, domestic imports of oil and petroleum products dropped 31.4% the month of February 1985 from the same month a year earlier. (API, 1985) The public's interest in investing in new oil recovery methods has been dissipated by the lower consumption of oil, the decline in the price of oil, the weakness of oil company securities, and the projected small increase in oil consumption over the next few years.

The investment options of the larger oil companies cause them to seek short-term objectives and quicker financial returns as opposed to a long-term oil mining project, which, to them, is unconventional, untried, and ties up their capital. The larger oil companies seek the highest returns possible in the shortest possible time from established conventional production methods to meet their overhead and to generate an acceptable profit for their stockholders. An oil mining pilot project that establishes commercial feasibility should cause industry to develop this resource now left in the ground.

U.S. research and development efforts by industry and government have tended to concentrate on the large-scale, long lead time technologies (i.e., oil shale, coal gasification, oil from coal, etc.). These technologies can possibly provide large volumes of petroleum products. It is probably the ease of controlling the large volumes of oil shale and coal that led the larger industries to choose these technologies over oil mining. Oil mining would require the task of assembling large tracts of land with their numerous lease and title problems in order to control development rights to a large enough block of land for a commercial oil mining project. Needless to say, the unfamiliar task of sinking shafts, driving tunnels, and drilling the many production holes necessary to exploit the resource might be unattractive to large-scale industries when compared to the ease of controlling a large volume of oil shale or coal for volume oil production.

The situation seems to imply that oil mining by gravity drainage is better adapted to new or small companies who have more time to devote to working out the problems. A new company does not have a massive overhead and a large number of stockholders to contend with.

The financial analysis in Chapter 4 was based upon published information and we were able to develop an oil mining economic model. The base case was adapted from the most likely parameters in order to determine a potential financial return. This base case indicated a DCFROR of 27.9%. The sensitivity analysis was run on key variables which included physical variables, oil price, royalty, and some tax parameters. It was found that the most critical of all the physical variables is the percentage of oil in place to be recovered from the reservoir. A 60% recovery over 8 years yields a DCFROR of 42.5% that falls to 9.7% should the recovery level drop to 40% of oil in place. The next parameter in importance on its effect on financial outcome is the length of time it takes to extract this production. A 6-year operational life at a 50% recovery of oil in place yields a DCFROR of 40.5%, an 8-year production level yields a DCFROR of 27.9% (base case) and a 10-year production life a DCFROR of 12.7%. The importance of the crude oil price parameter is not as sensitive as one might expect due to the fact that the price of #2 fuel oil moves up or down, either raising or lowering the operating costs, in a linear fashion, as the price per barrel of oil moves up or down. The 15% depletion allowance is the most important tax parameter affecting the financial results. (DCFROR drops from 27.9% to 20.6%).

After reviewing the literature on past and present oil mining operations existing on a world-wide basis, one can assume that oil mining is technically feasible. The present high cost of exploration for primary production when viewed against finding cost in oil mining makes technique attractive. Additionally, a review of the published material on the seemingly irreversible downward trend in domestic oil production coupled with a large potential target of 64 billion barrels of oil left in reservoirs that are amenable to the oil mining technique render the method even more attractive. There is always the great risk involved when a new technology is attempted. The high returns indicated as possible in the financial analysis have yet to be achieved in a full scale commercial oil mining operation. However, they indicate that further research and investigation is warranted. Russia would seem to have a technically successful operation, but it is not yet possible to determine if it is economic. There is always the inertia, the inability to persuade or convince management to attempt a new technology with which management is not familiar. Conventional oil production and the enhanced recovery techniques are established methods of recovering oil and gas from nature's reservoirs. A wise national energy policy should encourage all possible alternatives. Government financial aid is necessary because the technique has not yet been successfully demonstrated in a commercially successful project. Industry and the public will not bear the financial risks under present economic conditions. Once the operating risks have been solved, industry will step in and this resource will be developed and made available as an additional source of domestic supply.

Costs and benefits of a government program supporting a gravity drainage oil mining technique are summarized below:

Costs

The taxpayer pays part of the development costs of a pilot project by assistance in the form of production price support, investment tax credits, or elimination of the windfall profits tax for companies involved in oil mining by gravity drainage. Price guarantees with purchase agreements or loan guarantees with direct government participation are other methods whereby the taxpayer shares part of the development costs. From a tax standpoint, percentage depletion allowance is important with accelerated depreciation having a lesser effect on the economics. There will be some interference by the public sector in private enterprise and this is deemed a cost by many. Economic forecasters' projections for increased overall domestic oil consumption may not materialize. There seems to be a downward revision of energy forecasts over the years due to the high price of the commodity and because of elasticity of demand. The growth in the forecasted use of oil may be met from other sources such as new discoveries or substitute fuels.

Benefits

Increased domestic oil production will lead to a reduced dependence on foreign supplies located in politically unstable areas. Balance of payments would improve. There would be a reduction of OPEC power and its control over prices which implies lower oil prices and influence worldwide political stability. Creation of a new industry means additional profits and employment which, in turn, will increase tax income and eventually earn a large return for the taxpayers initial cost. The project results will be seen more quickly than the long-term results from oil shale or synthetic fuels. Minimal environmental damage is another advantage, as detailed in Chapter 3. More domestic oil and lower prices for the product implies a growth in GNP because of price elasticity of demand for oil. A number of financial incentive methods can be utilized which will require little administrative review and thus very low operational costs. Making this large potential resource available to future generations will mean more efficient utilization of the nation's resources. Slowing the switch to coal also implies less environmental damage. There should be growth of a number of small oil mining firms to compete in the marketplace. A lower cost for oil implies more chemical byproducts that will be made in the United States. Oil is the basic feedstock of the chemical industry. Oil-rich nations are all developing their chemical industries and moving into the world markets. With their low energy cost and access to the raw material, they could dominate the chemical market to the detriment of the U.S. chemical industry unless chemical raw material costs are kept down.

Based upon the author's research, it is concluded that:

1. Each oil-mining-by gravity-drainage project must be examined on an individual basis.

2. The necessity of steam injection in a reservoir must also be examined on an individual basis because each reservoir will react differently to the steam.

3. There must be some improvement of the data available as to the estimates of oil remaining in place after conventional primary and enhanced oil recovery techniques have been utilized. More information on the rock characteristics of the lower strata beneath the oil reservoirs is necessary to determine the feasibility of their supporting mine workings.

4. Our estimates of recovery of the oil in place by gravity drainage are not sufficient because of a lack of actual experience in the field and the differences that might occur due to reservoir characteristics.

5. More research and development is necessary in either a pilot operation or an industry mine in order to identify the technical problems and work them out. An increased knowledge of industry's understanding of the economics involved will also be gained.

6. More information from Russia as to the operation of the Yarega Mine would be helpful.
7. More detailed cost and production analysis of low pressure steam injection vs. high pressure steam injection rates must be done.
8. Laboratory experiments as to how the steam will react in a particular geological setting pending actual field experience would increase the knowledge in this area.

Energy independence means that government policies have to be redirected to give priority to the development of oil in all its forms. This will lay the foundation for an upsurge in production activity. Oil mining by gravity drainage is a technology with enormous potential. A pilot project would enable industry to solve the technical problems associated with the percentage of recovery of oil in place, the length of time it takes to recover this oil (sweep efficiency) and to find ways of reducing operating costs, such as using gas, leased crude or coal to generate the steam required in order to reduce oil viscosity. The cost to the taxpayer should be insignificant compared to the potential benefits that would be derived should the government decide to financially support the capital and operating costs of an oil mining by gravity drainage pilot project. Due to the long lead times involved in obtaining the necessary financing and setting up a pilot operation of this type, it would be wiser to act now rather than to wait for the next energy crisis.

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APPENDIX A

Computer Output Base Case and Comparative Reservoir Characteristics of Oil Mining Operations

Table A.1

Computer Output Base Case

Year	Gross Oil Production (MBbl)	1 PROD PAT Net Oil Production (MBbl)	Oil Price ($/Bbl)	1 PROD PAT Oil Revenue (M$)	1 PROD PAT Operating Costs (M$)	1 PROD PAT Share of WP Tax (M$)	1 PROD PAT State + Local Tax (M$)	1 PROD PAT Net Inc before FIT (M$)
0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1983.00	89.066	77.933	26.000	2026.252	2235.000	0.000	0.000	-208.748
1984.00	139.961	122.466	26.000	3164.113	2235.000	0.000	0.000	949.113
1985.00	190.856	166.999	26.000	4341.974	2235.000	0.000	0.000	2106.974
1986.00	190.856	166.999	26.000	4341.974	2235.000	0.000	0.000	2106.974
1987.00	190.856	166.999	26.000	4341.974	2235.000	0.000	0.000	2106.974
1988.00	165.409	144.733	26.000	3763.055	2235.000	0.000	0.000	1528.055
1989.00	165.409	144.733	26.000	3763.055	2235.000	0.000	0.000	1528.055
1990.00	139.961	122.466	26.000	3184.113	2235.000	0.000	0.000	949.113
	1272.374	1113.327		28946.508	17880.000	0.000	0.000	11066.509

Year	1 PROD PAT Deprec-iation (M$)	1 PROD PAT Depletion Allowed (M$)	1 PROD PAT Taxable Income (M$)	Investment Tax Credit on TANG (Decimal)	1 PROD PAT Federal Income Tax (M$)	1 PROD PAT Total Investment (M$)	1 PROD PAT Net Cash Flow (M$)	1 PROD PAT Disc Net Cash Flow (M$)
0.00	0.000	0.000	0.000	0.080	0.000	4590.000	-4590.000	-4590.000
1983.00	206.741	0.000	-3627.215	0.080	-1778.781	0.000	1570.032	1496.967
1984.00	303.221	322.946	322.946	0.080	148.555	0.000	800.558	693.911
1985.00	289.438	651.296	1166.240	0.080	536.470	0.000	1570.504	1237.534
1986.00	289.438	651.296	1166.240	0.080	536.470	0.000	1570.504	1125.031
1987.00	289.438	651.296	1166.240	0.080	536.470	0.000	1570.504	1022.756
1988.00	0.000	564.459	963.597	0.080	443.254	0.000	1084.800	642.229
1989.00	0.000	564.459	963.597	0.080	443.254	0.000	1084.800	583.845
1990.00	0.000	474.556	474.556	0.080	218.296	0.000	730.817	357.572
	1378.275	3880.307			1083.991	4590.000	5392.518	2569.844

Year	Oil Price ($/Bbl)	Adj Base Price for WPT Calc ($/Bbl)	1 PROD PAT Severence Tax Adj ($/Bbl)	1 PROD PAT "Windfall Profits" (M$)	1 PROD PAT WP Tax Bef TI Limit (M$)	1 PROD PAT Tax Inc (WPT only) (M$)	1 PROD PAT WP Tax Net Inc Limit (M$)	1 PROD PAT Share of WP Tax (M$)
0.00	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1983.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1984.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1985.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1986.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1987.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1988.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1989.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1990.00	26.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
				0.000	0.000	0.000	0.000	0.000

Table A.1

Computer Output Base Case

SINGLE POINT VALUES	
Discounted Cash Flow ROR (Before Tax), %	23.7730757403064694[illegible]
Discounted Cash Flow ROR (After Tax), %	27.878460769783199960
Sum of Net Cash Flow AFIT Disc @.100, M$	2569.844
Sum of Net Cash Flow AFIT Disc @.150, M$	1627.32[illegible]
Sum of Net Cash Flow AFIT Disc @.200, M$	884.765
Sum of Net Cash Flow AFIT Disc @.250, M$	290.067
Sum of Net Cash Flow AFIT Disc @.300, M$	-193.102
Sum of Net Cash Flow AFIT Disc @.350, M$	-590.953

COLUMN TOTALS	
Gross Oil Production (MBbl)	1272.374
1 PROD PAT Net Oil Production (MBbl)	1113.327
1 PROD PAT Oil Revenue (M$)	28946.508
1 PROD PAT Operating Costs (M$)	17080.000
1 PROD PAT Share of WP Tax (M$)	0.000
1 PROD PAT State + Local Tax (M$)	0.000
1 PROD PAT Net Inc Before FIT (M$)	11066.509
1 PROD PAT Deprec- iation (M$)	1378.275
1 PROD PAT Depletion Allowed (M$)	3880.307
1 PROD PAT Federal Income Tax (M$)	1083.991
1 PROD PAT Total Investment (M$)	4590.000
1 PROD PAT Net Cash Flow (M$)	5392.518
1 PROD PAT Disc Net Cash Flow (M$)	2569.844
1 PROD PAT "Windfall Profits" (M$)	0.000
1 PROD PAT WP Tax Bef TI Limit (M$)	0.000
1 PROD PAT Tax Inc (WPT only) (M$)	0.000
1 PROD PAT WP Tax Net Inc Limit (M$)	0.000
1 PROD PAT Share of WP Tax (M$)	0.000

Table A.1

Computer Output Base Case

```
ECON Version A.036                              Last Revision 29-Mar-84
Output from program ECON - run at 13:57          on 17-Nov-85
LISTING OF INPUT DATA
NAME "1 PROD PAT"
OUT* YEAR GROIL NIOIL OPRICE OILREV NIOPC WPTXMD SLTAX NIBTX
OUT* YEAR DEPR DPIL TAXIPC ITC FITAX WITINV ACF DNCF
OUT* YEAR OPRICE AHP STA WPMP WPTBIL WPTI WPNIL WPTXMD
SUM* DCFBTX DCFATX DNCF1 DNCF2 DNCF3 DNCF4 DNCF5 DNCF6
OLIN DNCF
SIZE 8
CALC ML
HED1 BASE CASE 11/15
HD1A $26.00/BBL OIL PRICE
HED2 GRAVITY DRAINAGE WITH THERMAL ASSISTANCE
HD2A $1,378,275 TOTAL DEPRECIABLE AMOUNT
HED3 BASE+ACC DEPR+DEPL+NO ST TX
HD3A AFIT CASH FLOW ($ THOUSANDS)
VARBC NII .875
VARBC WII 1
VARBC EFFDAT 0101.1983
TABL GROIL 99.066 133.961 190.856 190.856 190.856
TABL GHOIL 165.409 165.409 139.361
VARBC OPRICE 26.00
TABL OPCOST 2235 -9
TABL TANG 1378.275 0 -8
TABL INTANG 3211.725 0 -8
VARBC INDIV 1
VARBC PDRTE .15
VARBC PDTIL .5
VARBC RESERV 1272
VARBC WPTR .00
VARBC WPBP 22.25
VARBC FTXRTE .46
VARBC ADVTAX .00
VARBC DPRL 5
VARBC DPRTY 5
VARBC DPRTI 0
VARBC ITC .08
VARBC DISC1 .1
VARBC DISC2 .15
VARBC DISC3 .2
VARBC DISC4 .25
VARBC DISC5 .3
VARBC DISC6 .35
GO
```

Table A.2

Comparative Reservoir Characteristics of Oil Mining Operations

	French Mine at Pechelbronn	German Mine at Weitz	Steam Assist Proposed Mine in California N.E. McKittrick Field (EDC, 1983)	Conoco Wyoming Mine. North Tisdale Field. Now New Tech Mine	Steam Assist Russian Mine at at Yarega
Oil Sand Thickness	0 to 30 ft.	200 to 2,600 ft.	84 ft. Average	30 to 100 ft.	45 to 90 ft.
Depth of Reservoir	650 to 1,300 ft.	200 to 2,600 ft.	400 to 1200 ft.	300 to 500 ft.	596 to 660 ft.
Mine Depth	to 900 ft.	to 840 ft.	to 1000 ft.	to 550 ft.	to 700 ft.
% Recovered by Gravity Drainage	43.3%	42%	Estimated 50%		57.4%
Seepage Output or Production	2.57 BBLS per square ft. of seepage area 6,280,000 BBLS to 1952 cum. prod.	.98 BBLS per square ft. of seepage area 3,600,000 to BBLS to 1952 cum. prod.		68 BBLS per day declining to 28 per day 52,050 BBLS in 26 months	1974 Production 147,000 tons or 1,029,000 BBLS of oil
Viscosity	At 68°F 20 to 160 cp at 122°F 4 to 25 cp	(68°F) 1200 to 2300 cp (122°F) 140 to 175 cp	(90°F) 8500 cp	(70°F) 19 cp	(42°F) 16,000 cp (200°F) 30 cp
Porosity	22.5 to 35%	15% to 42%	35%	18.9%	20 to 25%
Permeability	(.4 inch) of water per minute passing through a disk 5.5 mm (one-fifth inch) thick, 1 cm diameter under a head of 85 lbs pressure	1,000 to 20,000 md	3,000 md	45 to 3,000 md to air	3.2 Darcies (Avg.)
API Gravity	26° to 29°	18.9°	11° to 17°	28°	17.5°

SENSITIVITY RUN

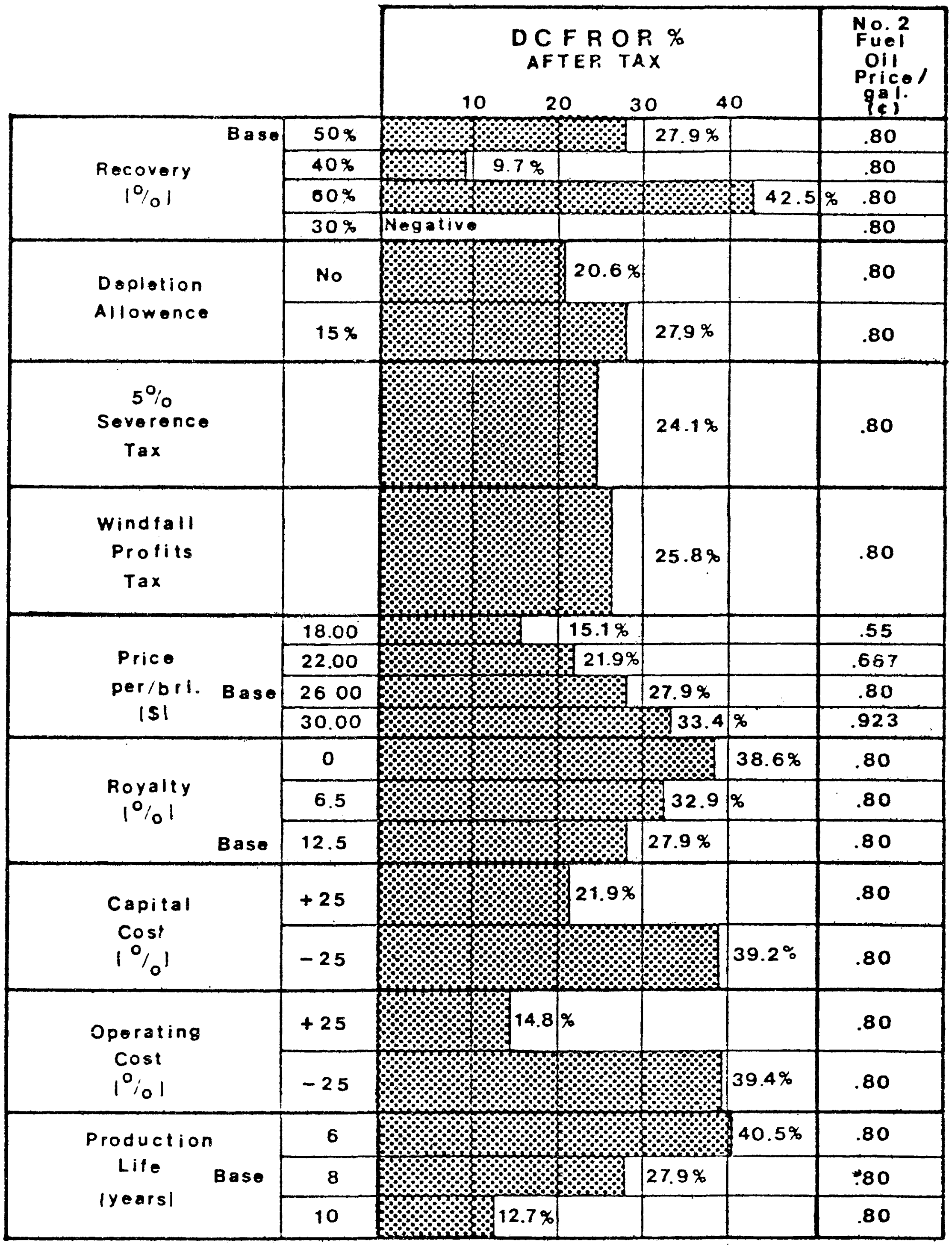


Figure A.3

Bar Chart of Sensitivity Runs

APPENDIX B

Declining Petroleum Production and Reserves in the United States and the High Cost of Exploration

Declining Petroleum Production and Reserves in the United States and the High Cost of Exploration

In a Rand study, "The Discovery of Significant Oil and Gas Fields in the United States," prepared in 1981, it was made very clear that the petroleum resources of the United States are highly concentrated in a limited number of productive provinces, as indicated in Table B.1. This indicates that certain geological characteristics are necessary for the accumulation of petroleum and that these particular characteristics will be either harder or impossible to find in the future. The eighteen provinces listed in Table B.1 contain 91.3% of the total national petroleum liquids and 92.9% of the national natural gas resources. The four largest provinces contain 61.6% of the known petroleum resources nationwide, 53.5% of the petroleum liquids, and 72.7% of the natural gas. The nine largest provinces contain 80.7% of the total known petroleum resources, 77.4% of the petroleum liquids, and 85.3% of the natural gas. These resources of the United States are not only concentrated in a small number of significant provinces but are also located in a relatively small number of significant fields (see Figures B.1 and B.2).

Table B.1

The Major Petroleum Provinces of the United States

Province	Geologic Age of Reservoirs	Petroleum Resources: Petroleum Liquids (10^9 bbl)	Petroleum Resources: Natural Gas (Tcf)	Petroleum Resources: Petroleum (10^9 bbl L&LE)	Distribution of Petroleum Resources by Field Size Category: AAAA	AAAA-A	AAAA-C
1. Gulf Coast	Cenozoic	40.1	299.5	90.0	22%+	77%+	94%
2. Permian	Paleozoic	31.3	74.4	43.7	51%+	82%+	94%
3. Anadarko-Amarillo	Paleozoic	6.7	117.6	26.3	72%	87%	96%
4. East Texas-Arkla	Mesozoic	15.2	50.6	23.6	48%	84%	94%
5. Arctic Slope	Mesozoic	10.1	26.0	14.5	98%	100%	100%
6. San Joaquin	Cenozoic	11.4	11.3	13.3	67%	95%	99%
7. Chautauqua	Paleozoic	8.5	15.0	11.0	22%+	61%+	86%
8. Appalachian	Paleozoic	3.6	39.0	10.1	N.A.	N.A.	N.A.
9. Los Angeles	Cenozoic	8.6	7.4	9.8	70%	98%	99%
10. South Oklahoma	Paleozoic	4.0	10.2	5.7	49%+	74%+	93%
11. San Juan	Mesozoic	0.8	22.0	4.5	75%	90%	96%
12. Illinois	Paleozoic	4.1	1.7	4.4	0%	59%	78%
13. Mid-Gulf Coast	Mesozoic	2.8	7.7	4.1	0%	68%	88%
14. Ventura	Cenozoic	3.1	5.3	4.0	44%	81%	97%
15. Bend	Paleozoic	2.2	5.4	3.1	0%	18%+	38%
16. Central Kansas	Paleozoic	2.6	1.8	2.9	0%	51%+	73%
17. Big Horn	Paleozoic, Mesozoic	2.4	1.5	2.7	23%	83%	95%
18. Powder River	Mesozoic, Paleozoic	2.4	1.3	2.6	30%	63%	86%
Total		159.9	697.7	276.3	43%+	81%+	94%

Source: Adapted from *The Discovery of Significant Oil and Gas Fields in the United States* by Richard Nehring with E. Reginald Van Driest, II, A. Rand Study, January 1981

Note: * See P. 15 of the Rand Study for Field size classification and L&LE (Liquid and Liquid Equivalants) conversion rate

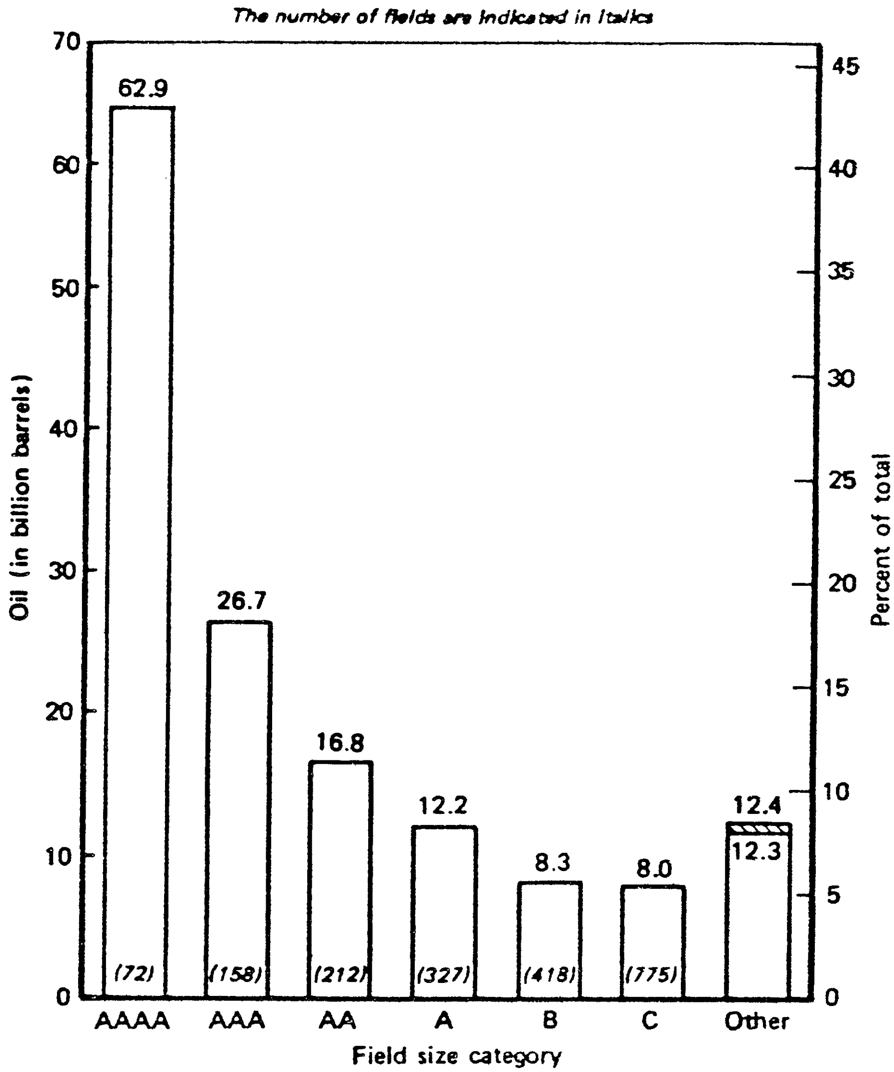


Figure B.1

Distribution of Crude Oil By Field Size Category In The United States (excluding Appalachia)

Source: <u>The Discovery of Significant Oil and Gas Fields in the United States</u> by Richard Nehring with E. Reginald Van Driest, II, A Rand Study, 1981

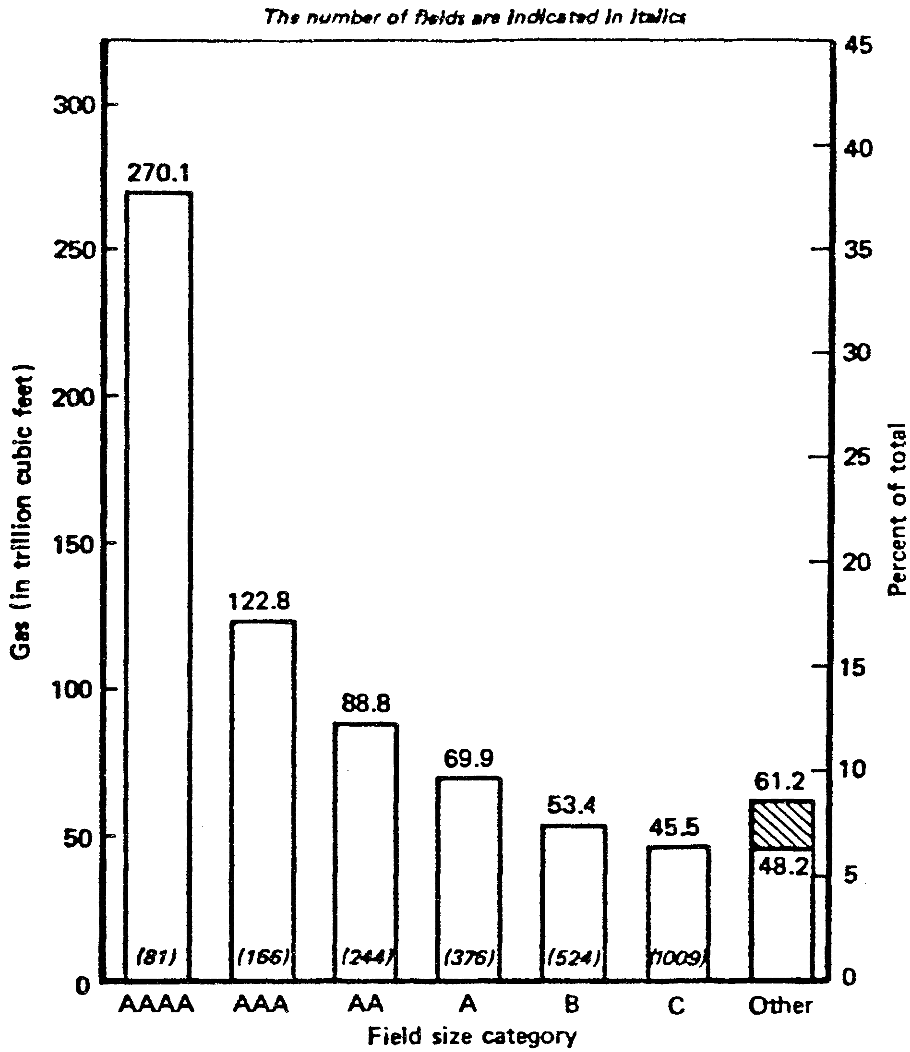


Figure B.2

Distribution of Natural Gas By Field Size Category In The United States (excluding Appalachia)

Source: The Discovery of Significant Oil and Gas Fields in the United States by Richard Nehring with E. Reginald Van Driest, II, A Rand Study, 1981

Distributions that are made on current estimates of total recovery indicate that cumulative production in these fields is a substantial portion of total reserves. The largest fields have low reserve to production ratios.

Because giant and large fields contain the vast majority of U.S. oil and gas resources, any serious attempt to evaluate future possibilities must take into account the geologic characteristics of these fields. Table B.2 summarizes by region the trap types of all giant and large oil fields discovered in the United States prior to 1976, excluding the Appalachia region. The giant and large fields of the United States are predominantly structural traps (anticlines or faulted anticlines); nearly all of the giant or large fields associated with salt domes are in southern Louisiana or Texas. Stratigraphic traps comprise only 8% of the total. Most are located in the Rocky Mountain region, the Permian Basin or the mid-continent. These subtle traps, 72 of the 873 giants (8.2%), are not appreciably different from the proportion of subtle traps worldwide. Although stratigraphic traps are a small proportion of giant and large fields, they constitute a major proportion of the largest fields. Four of the ten largest crude oil fields are pure stratigraphic traps. Four of the other six are

Table B.2

Trap Types of the Giant and Large Oil and Gas Fields in
United States, by Region
(in number of fields)

Region	Trap Type: Structural: Anticlines	Trap Type: Structural: Salt Domes	Trap Type: Structural: Other	Trap Type: Combination: Anticlinal	Trap Type: Combination: Other	Trap Type: Stratigraphic: Facies Change, Pinchouts	Trap Type: Stratigraphic: Other	Total Number of Fields
Alaska	11	0	0	1	1	0	0	13
California	40	0	5	20	11	3	0	79
Rocky Mountains	29	0	2	5	7	15	0	58
Permian Basin	56	0	0	27	2	12	10	107
North Central Texas	6	0	0	9	1	0	1	17
Mid-Continent	23	0	1	54	6	19	1	104
Western Gulf	70	19	8	23	17	2	1	140
Central Gulf	143	99	3	7	5	0	0	257
Northern Gulf	30	0	1	23	4	0	3	61
Eastern Gulf	11	3	0	6	1	0	0	21
Illinois-Michigan	8	0	0	5	0	3	0	16
United States (Ex-Appalachia)	427	121	20	180	55	54	16	873

Source: The Discovery of Significant Oil and Gas Fields in the United States by Richard Nehring with E. Reginald Van Driest, II, A Rand Survey, 1981.

anticlines modified by stratigraphic variations. While most of these large fields are subtle traps, it is important to note that they cover immense areas. Although their trap types (subtle stratigraphic) may be relatively nonvisible to conventional exploration techniques even at low density exploration drilling (one well every two townships), fields of this size cover such a large area that they are almost impossible to miss once exploration drilling begins in earnest.

The concentration of the oil and gas resources of the United States in giant and large fields appears to be the result of systematic geologic features. There are only a few regions--the stable interior (Rocky Mountain, Permian Basin, mid-continent, northcentral Texas, and the Illinois-Michigan basin)--where the known total petroleum resource is in small fields. In almost every other petroliferous area, giant and large fields predominate. The geology of these five areas is not conducive to large oil accumulations. The sedimentary cover is relatively thin with slower rates of deposition. Geologic stability over time results in little or no deformation of the sediments. This implies the lack of large, high relief anticlines. The areas containing large or giant oil fields have thicker sedimentary sections indicating rapid depositional rates or have undergone substantial deformation that created traps. These basic geologic characteristics differing from the other provinces result in large oil accumulations.

The conclusion of the 1981 Rand study is that the petroleum resources in the United States are highly concentrated in a few oil regions and are highly concentrated in giant and large fields with only approximately 8% contained in very small fields. Anticlinal traps, structural in nature, account for 70% of the giant and large petroleum accumulations.

Differences in the distribution of petroleum resources by field size and trap types are the result of differences in the geologic characteristics among the petroliferous regions. Because of the concentration of the oil resources in a relatively small number of giant and large fields, the number of significant oil and gas finds peaked in the decade around 1930. If it had not been for the discovery of Prudhoe Bay in 1968, the amount of oil and gas discovered would have declined continually since the peak. The amount of crude oil discovered in the early 1970s in the United States is the least discovered in any five-year period in this century. Excluding the amounts discovered offshore and in Alaska, the amount of crude oil discovered in the onshore lower 48 states has declined at an accelerating rate since the peak in the decade around 1930. From this peak to the decade around 1940, it dropped 15%; in the decade around 1950, 34%; and in the decade around 1960, 59%. Due to some large discoveries in the Rocky Mountains and eastern Gulf of Mexico regions, the decline was only 51% from the decade around 1960 to the decade around 1970 (Nehring, 1978). The peak in the amount of oil discovered coincides with the peak in the number of giant oil discoveries. The average size of significant oil and gas discoveries has also been declining for several decades, as giant and large discoveries have nearly ceased in the mature areas of the country.

These historical discovery patterns suggest that the U.S. petroleum industry is increasingly exhausting its geological possibilities, region by region. Increased drilling efforts are unlikely to reverse the decline in the ability to find oil in the lower 48 states. The advances in geological knowledge and in exploration techniques that have taken place in the last 40 years have not prevented these declines, although they have precluded more rapid drop-offs. These pessimistic patterns have been with the United States since 1940.

Some petroleum geologists take the position that a large number of small fields remain to be discovered. Thousands of small fields in the United States have been discovered, but they provide only a very small proportion of total U.S. petroleum resources. Two of the largest fields in the United States, Prudhoe Bay and Hugoton-Panhandle, contain 45% more petroleum in liquids and liquid equivalent than has been found in all the very small fields. Clearly, a very large number of small fields have to be discovered to provide even a modest amount of petroleum resources.

Since it is evident that the declines in both the number of significant discoveries and the amount discovered in the onshore lower 48 states are what might be expected in a heavily explored region, it has been proposed that the frontier regions of Alaska, the Overthrust Belt, and the offshore areas of the lower 48 states, none of which have been extensively explored, offer the promise of substantial additions to known U.S. petroleum resources (Rand Study, 1981). These frontier areas offer the best potential for major discoveries in the future. This 1981 Rand Study by Richard Nehring with Reginald Van Driest II indicates that the outlook for conventional petroleum resources in the United States can at best be characterized as only moderately promising. In other words, the drop in oil finding ability since the 1940s and 1950s, alleviated by the Prudhoe Bay discovery, will continue, as a direct result of the geological fact that oil resources are depleting. The study further indicates that at the 90% probability level, nearly two-thirds of the petroleum liquids and natural gas that will ultimately be produced have already been produced. Their estimate of the amounts to be produced after 1979 varies between 20 and 44 years of crude oil production and that most of the conventional petroleum that will ultimately be produced is in fields discovered before 1976, not in new discoveries. Large amounts of petroleum are discovered only if giant fields are discovered. Once an area is explored for petroleum, the giant and large fields are discovered early because they are obvious to exploration methods or cover large areas. The later exploration in these provinces is for smaller fields, unless they were technologically, economically, or politically inaccessible to earlier exploration. Another factor to add to the dismal statistic is that the United States, and particularly the lower 48 state onshore area, is the most explored petroleum province in the world. Any change in this trend would require a wholesale reversal of past discovery patterns established over many years of oil exploration. This is not likely.

Therefore, there is a compelling need to encourage all recovery production techniques for that two-thirds of the currently unrecovered resource remaining in the ground. Oil mining by gravity drainage, either with or without a thermal assist, is a very promising means of reaching this valuable resource. The dangers in not encouraging the domestic production of oil and gas in all possible forms have been previously demonstrated in the oil embargoes and periods of critical shortage in the past.

The High Cost of Exploration

As oil and gas exploration becomes more difficult, the undiscovered reserves that remain are the tough ones to find. They are often located in remote areas, at great depth, onshore or offshore, and in geological formations and physical environments which challenge the most advanced technology (Munk, 1981). The risks and the costs become greater as time goes on. For that reason, the returns on the investments made must increase, as well, to keep pace with the increasing risks. A significant portion of the world's petroleum resources which remain to be discovered are in the developing world (Munk, 1981). Investment and production development in those areas always carry with it the burden of political risk and contract renegotiation. It seems that the point may have been reached where more can be gained by allocating some of the human and financial resources to an area where a large known amount of the resource exists, and apply our abilities and energies to extracting it by mining oil. The professional activity known as "exploration management" consists of optimally allocating scarce resources (people, cash, and hardware) in order to determine the existence, geographical location, and size of petroleum reserves. By judiciously using scientific methods and techniques, rather than random drilling, the chance of finding oil is increased. Exploration is an integrated team activity, bringing together experts and specialists such as geologists, geophysicists, petroleum and reservoir engineers, stratigraphers, and geochemists who can put the jigsaw puzzle together. The main managerial task is recognizing and deploying these rare individuals with a "flair" for their discipline and coordinating this know-how with the equipment in a way to produce actual results;

that is, to find and produce oil and gas. Managing all the individual tasks and services provided by a host of consultants, subcontractors, and in-house experts, and arranging the financial and legal issues, all within the framework of an overall economic efficiency, is a complex task requiring an expertise which only a few companies have. Figure B.3 is a model of the exploration management process.

The acquisition of the exploration data which is of a primary nature (e.g., seismic and well log data) is obtained in the field using capital intensive equipment and technically trained personnel, and accounts for about 80% of total exploration costs. Table B.3 sets forth some of the necessary major technologies. Table B.4 lists some of the disciplines required for a technical analysis of the exploration data. This is a rapidly evolving area of activity. Half of these techniques were not in use 20 years ago.

The third step in the flow chart diagram is project appraisal. The amount of oil and gas which may be present in an undrilled prospect, trap, acreage block, or basin must be estimated. This estimate improves the quality of investment decision making by giving a better idea of the chance of success and the range of potential rewards. Any

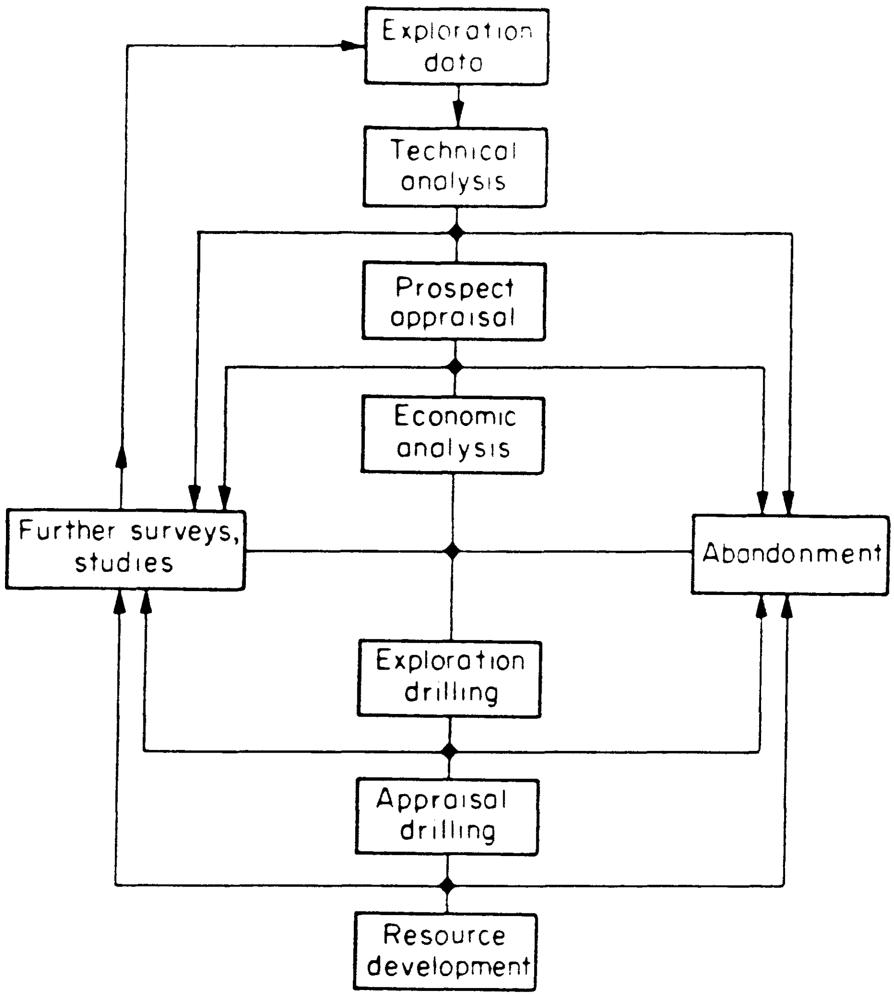


Figure B.3

Simplified Model of the Exploration Management Process

Source: <u>Petroleum Exploration Methods, Techniques and Costs</u>, P. Kassler, Graham and Trotman Limited, 1981.

Table B.3

Primary Exploration Data

Aerial photographs
Airborne magnetometer data
Field geological observations:
hydrocarbon shows
macrofossils
microfossils
rock descriptions
rock sequences
structural information
unconformities
Gravity data
Reflection seismic data
Satellite images
Well information:
hydrocarbon shows
palaeontology
petrophysical logs
sample and core lithology description
structural information
test results
velocity surveys
etc.

Source: Petroleum Exploration Methods, Techniques and Costs, P. Kassler, Graham and Trotman Limited, 1981.

Table B.4

Technical Analysis

Technical Analysis Disciplines
Acoustic impedance studies
Aeromagnetic interpretation
Basin classification
Carbon isotope analysis
Clay minerology
Core analysis
Data reformatting/display
Diagenetic study
Direct hydrocarbon indication analysis
DST/FIT analysis
Gravity interpretatoi
Greoundwater geochemistry
Hydrodynamics
Oil/Gas analysis
Oil/gas migration path analysis
Organic metamorphism determination
Palaeoclimatology
Palaeogeography
Palaeogeomorphology
Palaeo-sealevel studies
Palaeo-ecology
Petrophysical log processing/analysis
Photogeologic interpretation
Plate tectonic analysis
Porosity analysis/prediction
Radiometric age determination
Regional geology
Satellite image processing and analysis
Seal capacity analysis
Sedimentary environmental modeling
Seismic amplitude analysis
Seismic data processing
Seismic 3D Modeling
Seismic facies calibration
Seismic/surfce geological correlation
Seismic velocity analysis
Source rock/hydrocarbon correlation
Source rock type/richness evaluation
Stratigraphic correlation
Stress field analysis
Structural mapping/cross section construction
Structural style analysis
Subsurface pressure analysis
Subsurface temperature analysis thermics
Synthetic seismogram construction/analysis
Vulcanology

Source: Petroleum Exploration Methods, Techniques and Costs, P. Kassler, Graham and Trotman Limited, 1981.

technique which reduces the investor's risk exposure, even by a small amount, is enormously valuable. The amount and quality of the exploration data available (seismic and well logs) will affect the appraisal estimate. The Shell Oil Company uses a computer model that can be used to simulate the geological subsurface process of generation, migration, accumulation and retention of oil and gas (see Figure B.4). The model was based on a large data bank of 500 oil and gas fields and dry wells from all over the world. The simulation is based on Monte Carlo statistical techniques. The result of the simulation is a set of expected curves of recoverable oil and gas with minimum recoverable volumes at various levels of probability.

The Shell Oil Company experience is as follows. The actual costs of exploration cover a wide range depending on the nature of the terrain being explored (offshore, onshore, low-lying or mountains, swamp, jungle, desert or cultivated, etc.) and on the complexity of the geology being surveyed or drilled. Offshore seismic costs currently fall into the range of $600,000 to $1,000,000 per crew-month or $500 to $1,000 per km surveyed with an average of $700. Onshore seismic data has involved the

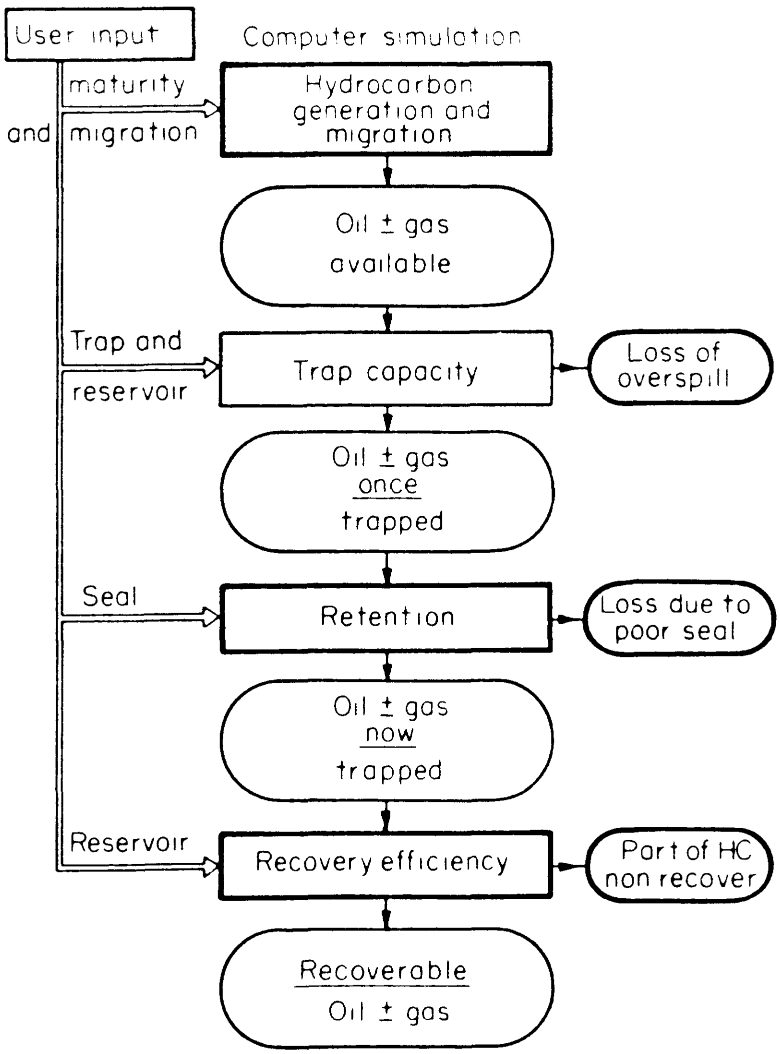


Figure B.4

Simplified Flow Chart of the Simulation Procedure

Source: Adapted from Petroleum Exploration Methods, Techniques and Costs, P. Kassler, Graham and Trotman Ltd. 1981.

following 1980 costs: (Petroleum Exploration Methods, Techniques and Costs, by P. Kassler, Graham and Trotman Limited, March, 1981)

	CREW-MONTH	PER km
Desert Areas	$ 400,000	$ 2,500
Western Europe	$ 350,000	$ 3,500
Tropical Jungle	$1,000,000	$25,000

Offshore drilling costs can run in the range of $3 million to $5 million per month. Onshore drilling costs for a heavy land rig in a deep exploration campaign in a new area are in the range of $1 million to $2 million per string month. Thought and planning must be given to the effect inflation has on these costs.

The costs of the special studies and technical analysis, as well as the back-up research necessary to maintain them, average about 20% of the data acquisition costs in any one venture.

Six new venture exploration programs of the Shell Oil Company were as follows: (Table B.5)

TABLE B.5

Total Costs of (Six) Exploration Programs

VENTURE	(a) WELLS DRILLED	(b) COST (in millions of 1980 Dollars)	(c) COST Per Well
A Offshore	1	21	21
B Onshore, Desert	2	22	11
C Offshore	9	79	9
D Onshore, Desert	5	93	19
E Onshore/Offshore Africa	4	32	8
F Onshore, Latin America	1	7	7

Source: From Petroleum Exploration Methods, Techniques and Costs, by P. Kassler, Graham and Trotman Limited, March, 1981.

Note: Column (c) is calculated by the author

Successful exploration demands the very best technologies, the most experienced people, and the most careful exploration management. All of this is very expensive in terms of cash and the required skilled technicians.

Exploration costs have been estimated at \$12 to \$15 per barrel of oil discovered as per the Arthur Anderson Survey (Oil and Gas Industry Services Programs, Houston, Texas, 1983). When oil prices are declining from a high of \$34 per barrel in 1982 to the \$26 range in 1985, there is not much room left for a company to meet its overhead and offer its stockholders an appropriate return on their investment; this does not include the cost of lifting the oil which must be added to the costs of exploration and decreases the profit margin even further. This explains the rash of oil company mergers and takeover attempts in 1983 and 1984. With the 1985 price of oil securities at low prices, it has become wiser to buy proven reserves by purchasing enough stock of a company to control its assets, thereby controlling its proven reserves, the principal asset of the producer. The high risk exploration activity is also avoided by "buying reserves on Wall Street."

In a survey conducted by Arthur Andersen & Co. (Oil and Gas Industry Services Program, Houston, Texas, 1983), of 300 public companies involved in the production of oil and gas from 1980 to 1982, the following information was obtained (see Tables B.6 and B.7).

Oil reserves declined 6.6% in the United States and 4.7% worldwide. The decline in proved reserves resulted from a continuing inability of companies to find sufficient new reserves to replace their current production, despite a massive level of expenditures for exploration and development. These expenditures averaged $58 billion

Table B.6

Total Proved Reserves of Oil
(in millions of barrels)

	DOMESTIC				WORLDWIDE			
	Three-Year Total	1982	1981	1980	Three-Year Total	1982	1981	1980
Beginning of Period	24,811	23,802	24,388	24,811	39,520	38,539	39,360	39,520
Revisions	1,176	279	399	498	1,697	604	175	918
Additions*	3,762	1,175	1,302	1,285	6,299	1,926	2,107	2,266
Production	(7,036)	(2,121)	(2,338)	(2,377)	(10,683)	(3,551)	(3,515)	(3,617)
Purchase of Reserves in-Place	660	358	75	277	1,168	382	456	330
Sales of Reserves in-Place	(196)	(116)	(24)	(56)	(351)	(250)	(44)	(57)
End of Period	23,177	23,177	23,802	24,388	37,650	37,650	38,539	39,360

* Additions include extensions and discoveries plus improved recoveries.

Source: Arthur Andersen & Co., Oil and Gas Industry Services Program, Houston, Texas, 1983

Table B.7

Total Proved Reserves of Oil
(% of change)

	DOMESTIC				WORLDWIDE			
	Three-Year Total	1982	1981	1980	Three-Year Total	1982	1981	1980
Beginning of Period	100.0%	95.9%	98.3%	100.0%	100.0%	97.5%	99.6%	100.0%
Revisions	4.8	1.2	1.6	2.0	4.2	1.5	0.4	2.3
Additions*	15.1	4.7	5.2	5.2	15.9	4.9	5.3	5.7
Production	(28.4)	(9.4)	(9.4)	(9.6)	(27.1)	(9.0)	(8.9)	(9.2)
Purchase of Reserves in-Place	2.7	1.5	0.3	0.9	3.1	1.0	1.2	0.9
Sales of Reserves in-Place	(0.8)	(0.5)	(0.1)	(0.2)	(0.8)	(0.6)	(0.1)	(0.1)
Balance, End of Period	93.4%	93.4%	95.9%	98.3%	95.3%	95.3%	97.5%	99.6%

* As a percent of the 1980 beginning-of-year balance.

Source: Arthur Andersen & Co., Oil and Gas Industry Services Program, Houston, Texas, 1983

each year for 1980, 1981, and 1982, yet were not sufficient to replace production. Companies found fewer new reserves in 1982 than in 1980 or 1981. For the 300 companies in this survey, oil is produced almost twice as rapidly as new discoveries are being made (Table B.8).

Petroleum Information International Corp. of Houston, reports that U.S. reserves as of January 1, 1984, dropped from 27.7 billion barrels to 27.3 billion barrels as of January 1, 1985, while the reserves of the Soviet Union and its allies, including China, were virtually unchanged at 83.7 billion barrels as of January 1, 1985, compared with 83.5 billion barrels a year earlier. The largest reserve increases occurred among Middle East OPEC countries where reserves totaled 448.8 billion barrels of oil as of January 1, 1985, up 32 billion from January 1, 1984.

The replacement ratios for major oil companies were much lower than for those of smaller companies (see Table B.9). Some of the reasons for these lower ratios are (1) the substantial size of the major companies' reserves and production from giant fields discovered many years ago which may not be replaceable, and (2) lower expenditures in relation to net production revenues which might be due to a lack of suitable prospects in which to invest, or

Table B.8

Quantity Replacement Ratios

	Domestic				Worldwide			
	Three-Year Total	1982	1981	1980	Three-Year Total	1982	1981	1980
OIL								
Additions* (MMBBLS)	3,762	1,175	1,302	1,285	6,299	1,925	2,106	2,268
Production (MMBBLS)	7,034	2,321	2,336	2,377	10,679	3,547	3,515	3,617
Replacement percent	53%	51%	56%	54%	59%	54%	60%	63%

* Extensions and discoveries plus improved recoveries.

Source: Arthur Andersen & Co., Oil and Gas Industry Services Program, Houston, Texas, 1983

TABLE B.9

Three-Year Cumulative Ratios 1980-1982

	QUANTITY REPLACEMENT RATIOS(a) OIL		DOLLAR REPLACEMENT RATIOS	PLOWBACK RATIOS
	DOMESTIC	WORLDWIDE	WORLD-WIDE(b)	WORLD-WIDE(c)
Majors	46%	53%	34%	57%
Independents	93	95	87	107
Integrated Pipeline/	88	66	76	91
Utility	80	171	84	119
Diversified	101	79	64	94
Average	53%	59%	44%	67%

(a) Reserve addition (extensions and discoveries plus improved recoveries) divided by reserves produced during the period.

(b) Discounted future net cash flows of reserve additions divided by actual net revenues from production (after production costs).

(c) Costs incurred in acquisition of unproved properties, exploration and development divided by net revenues from production.

Source: Adapted from Arthur Andersen & Co., Oil and Gas Industry Services Program, Houston, Texas, 1983.

demands on available capital from dual taxation problems, or the necessity to provide their shareholders with dividends.

It would seem that the problems the majors have in replacing reserves automatically become the concern of the nation because of the geographic concentration of the giant fields, coupled with their ownership in the hands of a few large major companies. The fact that the smaller companies replace 80 to 90% of their reserve base mitigates the deterioration of this prime national asset. (Adkerson, 1983)

Assessing the relative efficiency of different companies' finding costs is a difficult task. The nature of the exploration and development activity over a longtime span creates the major problem. There also is a problem in defining what a finding cost is, the timing of that cost and its inclusion into a specific accounting period. Another problem is the imprecise nature of estimating reserves at the point of discovery. The survey points out that by using what data are available however arrived at by the companies surveyed, the information, nevertheless, provides some insight into the direction the costs are taking (see Table B.10).

Table B.10

Finding Cost Surrogates

	DOMESTIC				WORLDWIDE			
	Three-Year Total	1982	1981	1980	Three-Year Total	1982	1981	1980
COST INCURRED (in $ millions)								
Acquisition of unproved prop.	$ 27,513	$ 8,079	$11,645(a)	$ 7,789(a)	$ 32,317	$ 8,705	$14,068(a)	$ 9,544(a)
Exploration	39,657	15,051	14,551	10,055	57,146	21,419	20,641	15,086
Development	53,551	20,644	19,547	13,360	76,298	29,245	27,038	20,015
	$120,721	$43,774	$45,743	$31,204	$165,761	$59,369	$61,747	$44,645
RESERVE CHANGES (MMNEBS (b)								
Additions	8,509	2,649	3,021	2,938	12,940	3,806	4,287	4,847
Revisions	1,317	444	520	353	2,318	928	639	751
Additions and Revisions	9,826	3,093	3,541	3,192	15,258	4,734	4,926	5,598
PER BARREL COSTS INCURRED								
Excluding Revisions	$ 14.19	$ 16.52	$15.14	$ 10.99	$ 12.81	$ 15.60	$ 14.41	$ 9.21
Including Revisions	$ 12.28	$ 14.15	$ 12.92	$ 9.78	$ 10.86	$ 12.54	$ 12.53	$ 7.98

(a) **Includes an unspecified amount for acquisition costs attributable to purchase of reserves in-place for Dome Petroleum's acquisition of Hudson's Bay Oil and Gas Co. Limited during 1981 and Kaiser Petroleum Ltd. in 1980.**

(b) **Includes crude oil, condensate and natural gas liquids, plus natural gas converted at 6 mcf to one barrel. Additions include extensions and discoveries, plus reserves added through improved recoveries.**

Source: Arthur Andersen & Co., Oil and Gas Industry Services Program, Houston, Texas, 1983

Per barrel costs incurred increased 10% to 12% in 1982 after steep rises in 1981 (37% to 50%) and in 1980 (6% to 13%). Beginning in the last half of 1982, costs of drilling began to decline at precipitous rates (25% to 40%), and per barrel costs continued to decrease throughout 1983.

An exploration and production company must continually replace its depleting reserve base to maintain its ability to operate and to produce revenues in the future. A company must find new reserves at a cost less than the value (over time) of the reserves discovered, and it has to expend sufficient sums to replace the reserves that are produced and sold. (Table B.11) Companies may be efficient in their exploration and development activity, yet may not expend enough to find sufficient new reserves to achieve full replacement of the reserves produced. This pressure to replace a companies depleting primary asset, its reserve base, is true of the nation when viewing its total reserve base. One method to alleviate this inability to repalce current domestic production would be to mine the oil left in the reservoirs after conventional production.

Table B.11

Exploration Profits

	Three-Year Total	1982	1981	1980
Additions, net	$108,709	$ 31,848	$ 38,728	$ 38,133
Evaluated Costs	(82,854)	(30,872)	(30,997)	(20,715)
Exploration Profits	$ 25,855	$ 976	$ 7,731	$ 17,418
Per Barrel of Additions (NEB's)				
Additions	$ 8.40	$ 8.36	$ 9.03	$ 7.87
Evaluated Costs	(6.40)	(8.11)	(7.23)	(7.27)
Exploration Profits	$ 2.00	$ .25	$ 1.80	$ 3.60

Source: Arthur Andersen & Co., Oil and Gas Industry Services Program, Houston, Texas, 1983

APPENDIX C

The French Oil Mine at Pechelbronn

The French Oil Mine at Pechelbronn

The French Project at Pechelbronn (George S. Rice, 1932) (Figures C.5-C.8) The reservoir rock consists of alternating sands and marls. The oil bearing sands are lenticular with individual thicknesses of 7 to 10 feet and depths of 656 to 1,312 feet. They are medium-hard sandstones as well as loosely cemented sands. Over 5,000 wells have been drilled previously into this reservoir which has produced close to 20 million barrels. Oil mining has accounted for 6,280,000 barrels while over 13,000,000 barrels were obtained by the drilling of wells.

Because the oil has an API gravity of 26^{o} to 29^{o}, its flow reactions are much more favorable than those of the heavy oil at the Wietze mine. The properties of this light oil resulted in repeated blowouts and explosions at Pechelbronn until 1925. These were controlled only after small gas vent holes were drilled at the heads of the tunnels.

The mine at Wietze was much more intensively drained before the mining than was the mine at Pechelbronn. The reservoir at Pechelbronn by no means had reached the advanced stage of depletion that the Wietze mine had.

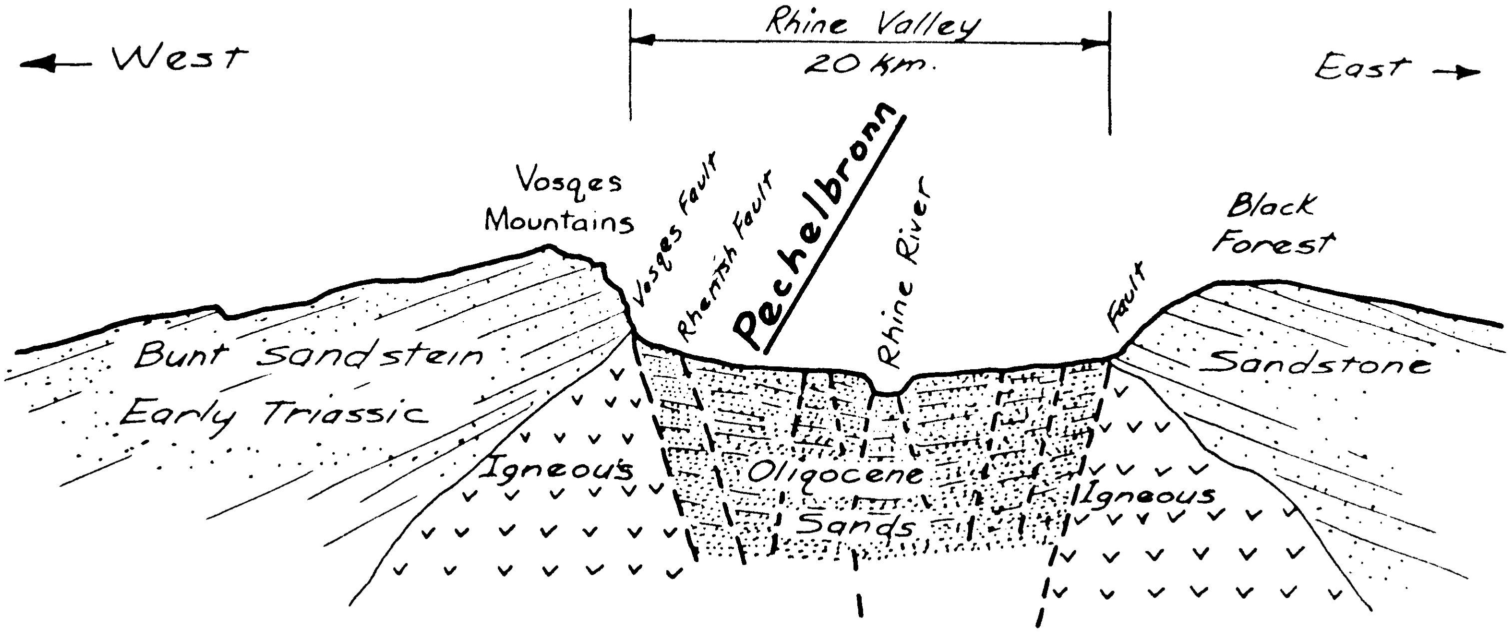


Figure C.5

Geologic Cross Section West to East of Pechelbronn Oil Field

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

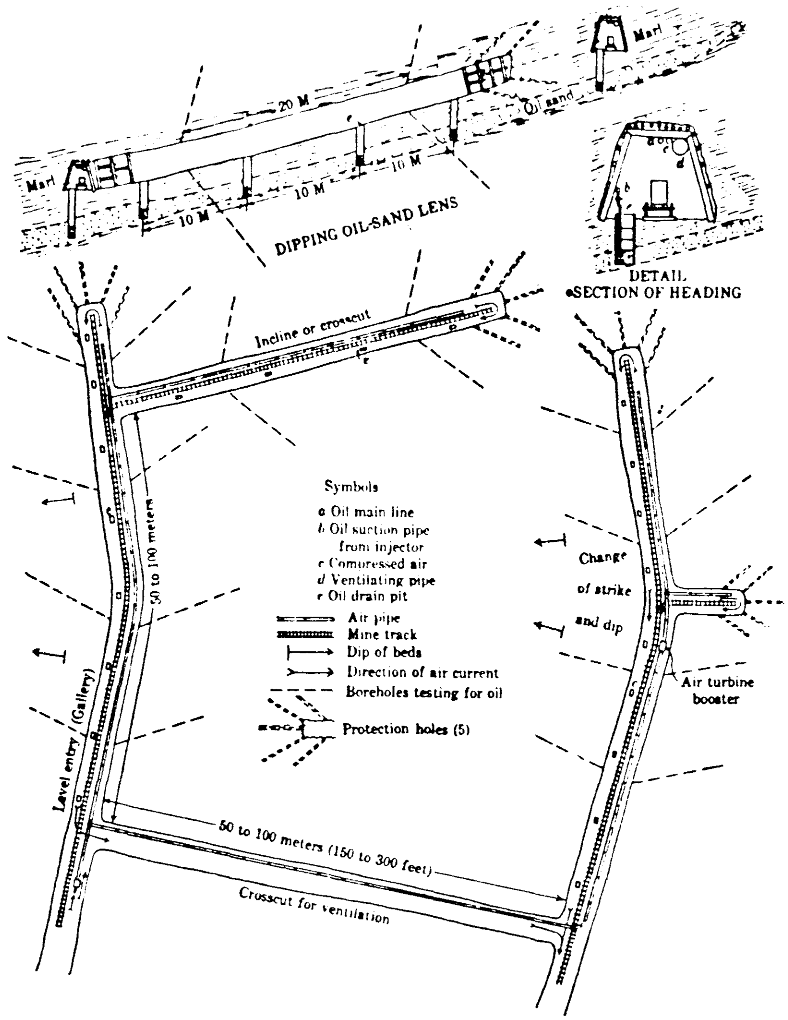


Figure C.6

Pechelbronn System of Mining to Drain Oil Sand (1930)

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

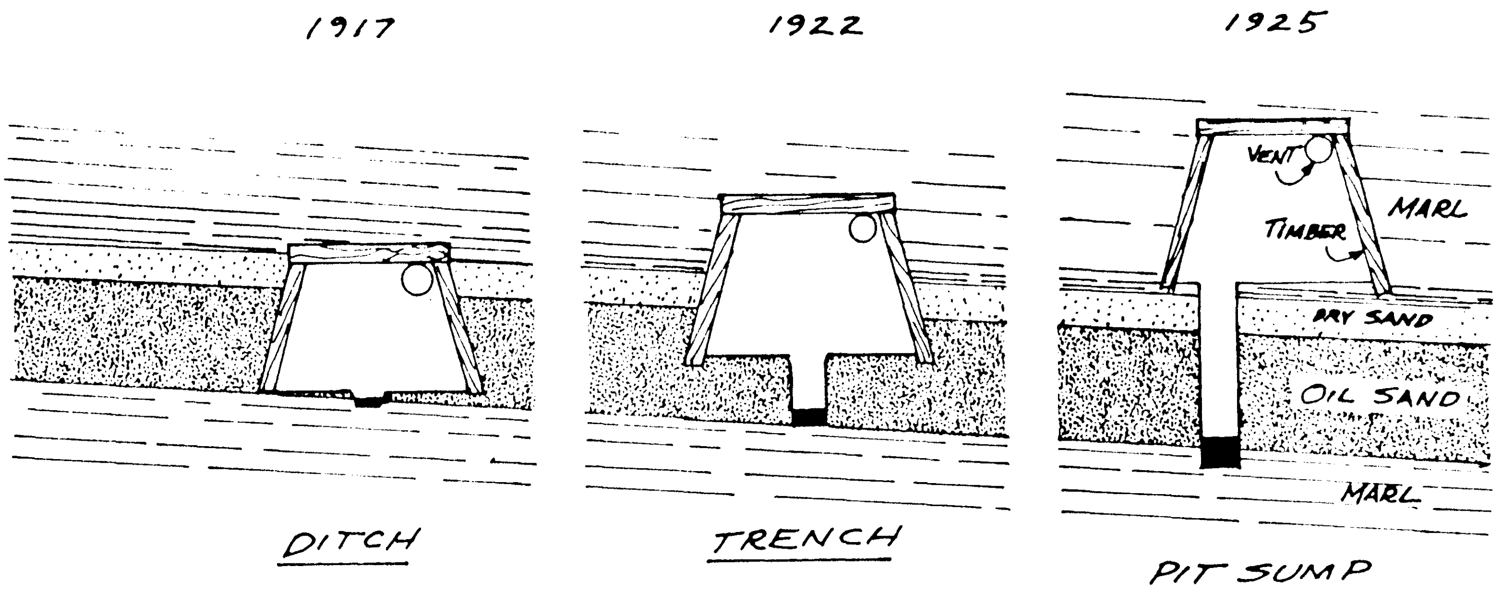


Figure C.7

Pechelbronn Successive Positions of Gallery in Relation to Oil Sand

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

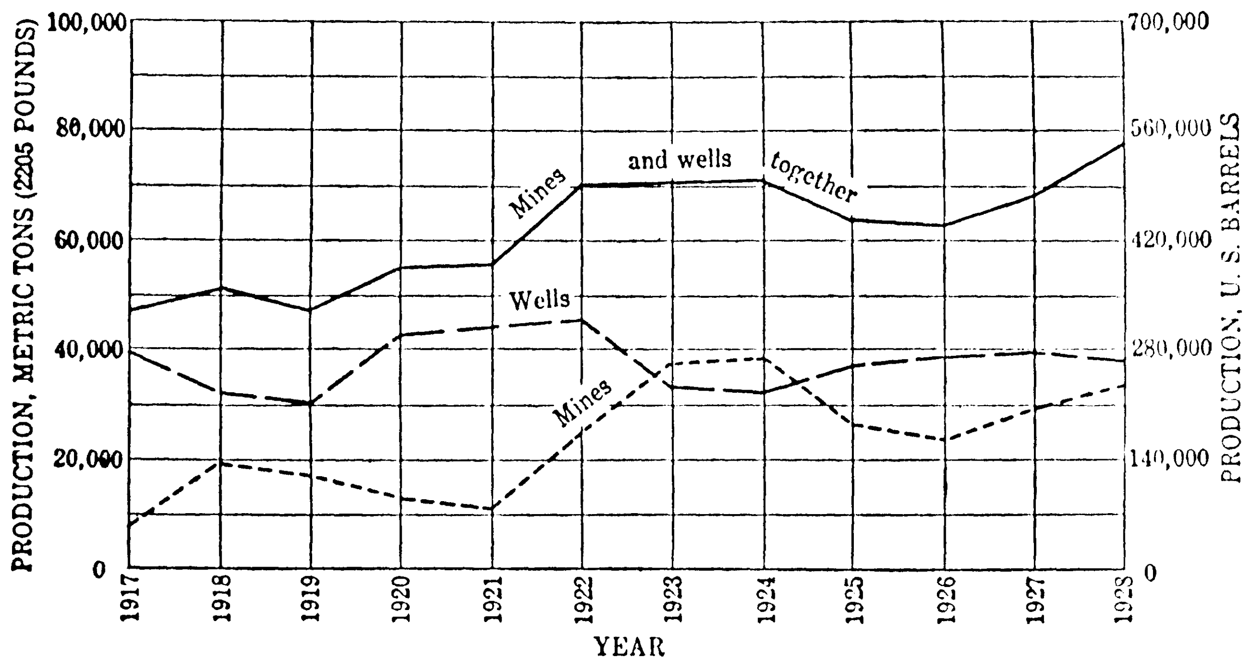


Figure C.8

Pechelbronn Oil Production From Wells and Mines

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

At Pechelbronn, the tunnels were driven into the oil sands until 1923; after that, they were driven into the overburden, and the deposits were exploited by shafts at intervals of 33 ft. The drainage areas were much greater at Wietze than at Pechelbronn due to the prior production before mining.

Until 1952 the Wietze mine produced 3,600,000 barrels by seepage against 6,280,000 barrels at Pechelbronn. This gave an output of 0.98 bbls. of oil per square foot of seepage area at Wietze compared with 2.57 bbls. at Pechelbronn. It may be assumed that the advantage at Pechelbronn was due to the fact that the reservoir was less depleted than the German mine when mining started, and that the oil at Pechelbronn was less viscous.

Pechelbronn shafts were driven from 492 feet to 656 feet from which tunnels were driven into the field. The lenticular oil reservoirs were tapped by drill holes or underground shafts with cross-sections of no more than 23 feet by 23 feet. The oil accumulating in them was pumped to the surface. Tunnels were no longer driven into the reservoir because of the loosing of the sandstone, the loss of gas which could be utilized as a driving energy, and the danger of gas blowouts.

APPENDIX D

The German Oil Mine at Weitze

German Oil Mining Project at Wietze

The project at Wietze (Figures D.9-D.12) operated profitably for 35 years and was so safe technically that the method may be regarded as having been completely under control. In 32 years, the mine produced 5 million bbls. of oil, 75% of which was produced by the seepage or self drainage method. (F. Hoffmann and Walter Ruehl, 1953).

Two mining methods were used at Wietze. One was the excavation of the oil sand, the other was the seepage of oil from walls of the tunnels caused by the oil's own gravity. Thirty-seven horizontal wells were driven from drilling chambers in a tunnel into the reservoir. The porosity of the sands vary from 15% to 42% and the permeability varies from 1,000 and 20,000 MDY. The properties of the sands at Wietze are very similar to the Athabasca tar sands in Canada; the oil at Wietze is less viscous but is still classified as heavy oil similar to the same type encountered on salt domes around the world. There is no gas or water drive whatsoever and this condition started the oil mining method. The oil recovery showed improvement at low atmospheric pressure rather than at high pressures.

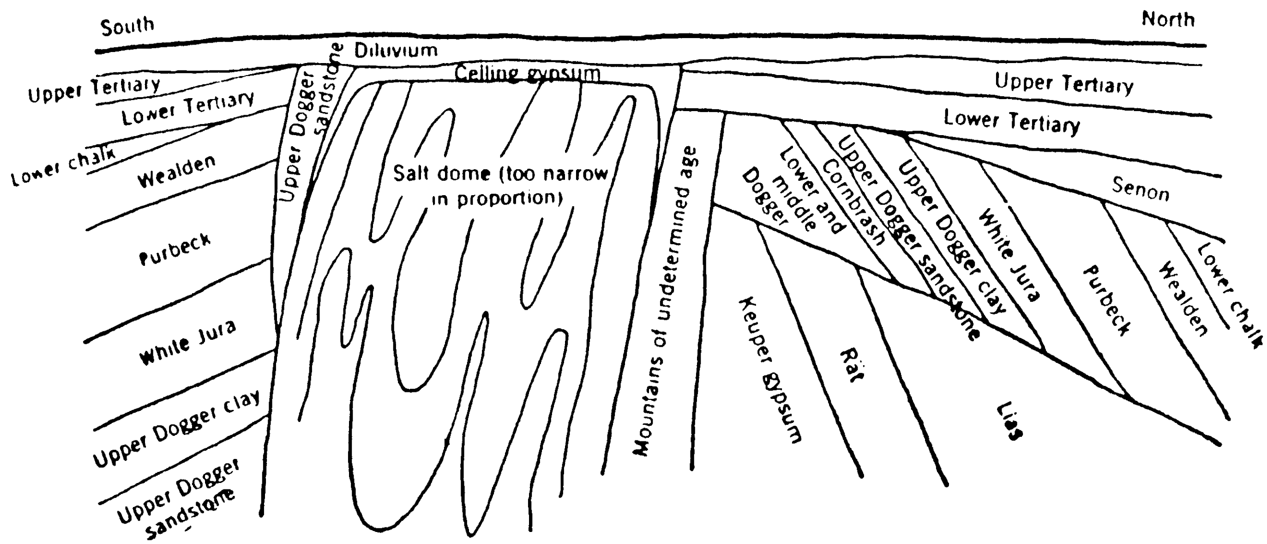


Figure D.9

Geologic Cross Section North to South Through Weitze Oil Field and Salt Dome

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

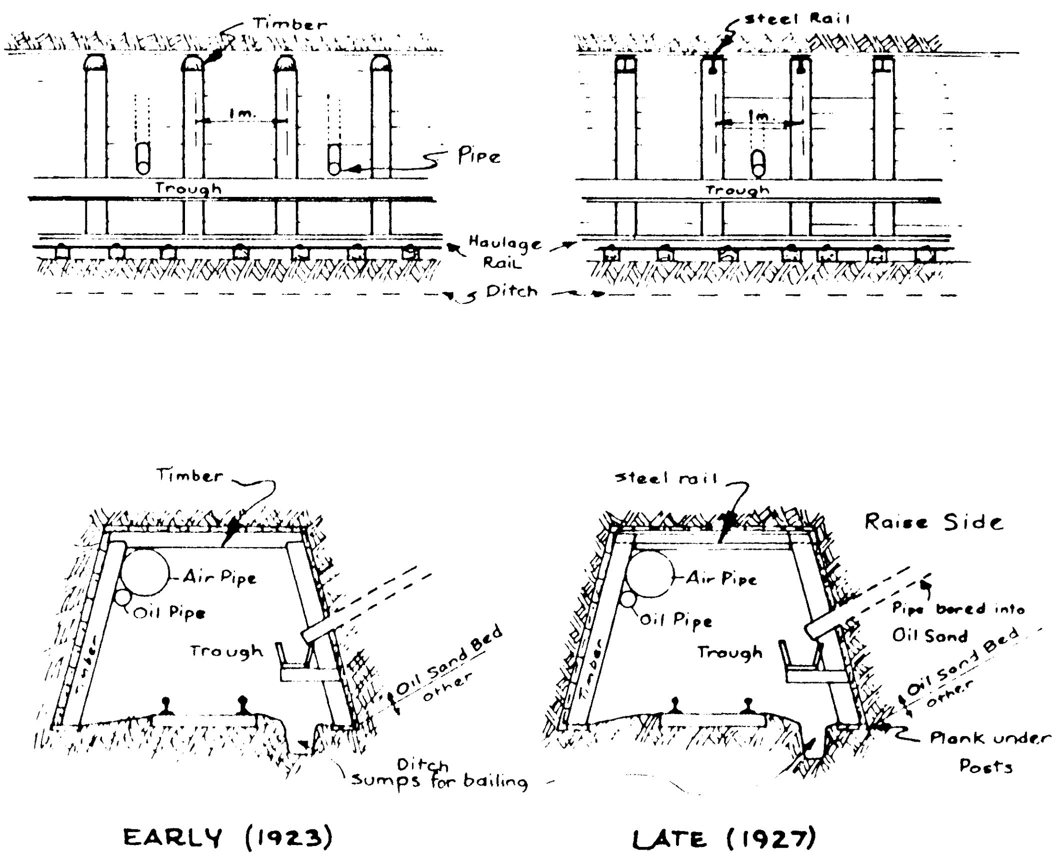


Figure D.10

Cross Sections of Oil Draining Galley at Weitze

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

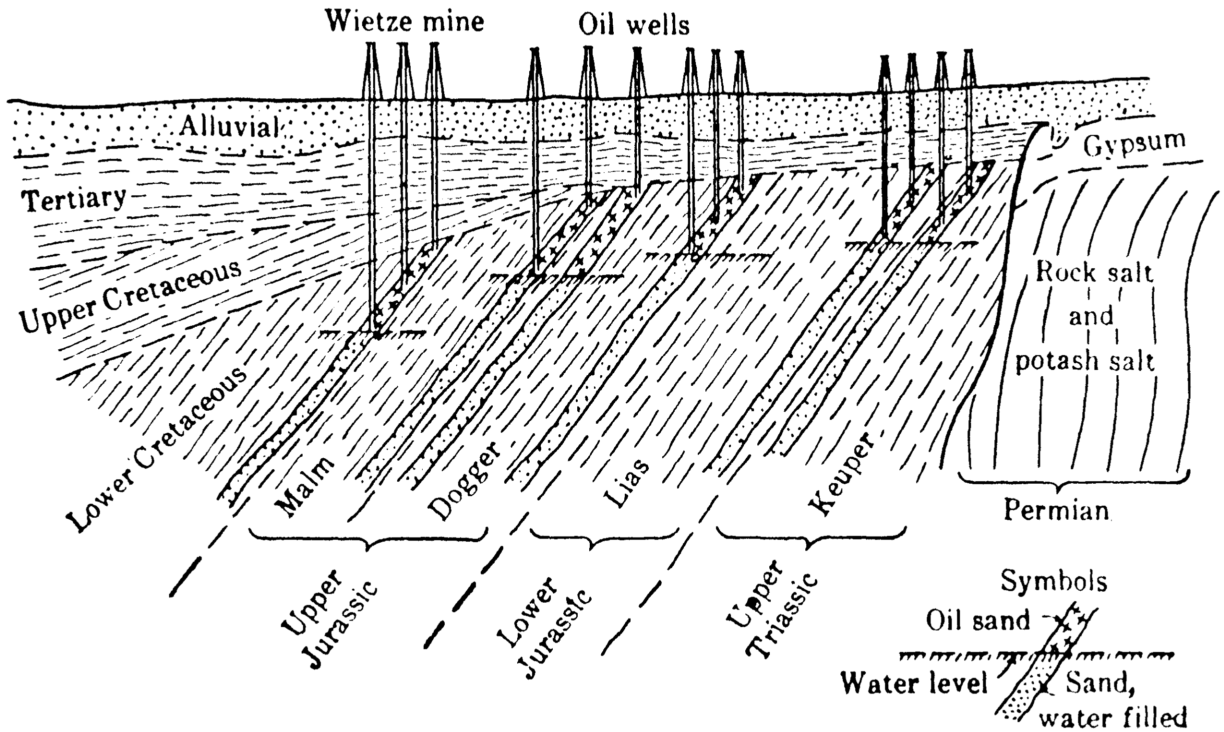
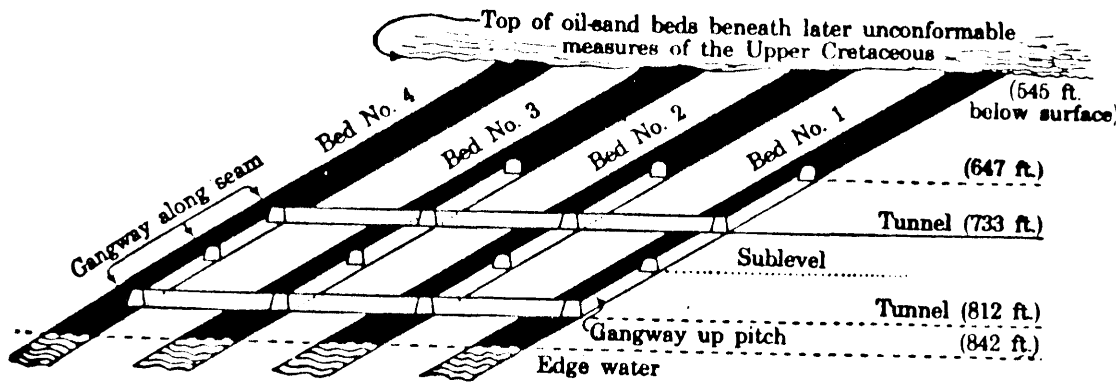


Figure D.11

Cross Section of Oil Bearing Strata at the Weitze Oil Mine Near Hannover, Germany

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932



(Not to scale and not showing true dip of beds)

Figure D.12

Typical Cross Section of Oil Sand Beds at Weitze Mine Showing Principal Levels and Elevation of Edge Water

Source: George S. Rice, "Mining Petroleum by Underground Methods," U.S. Bureau of Mines Bulletin, 351, U.S. Department of Commerce, U.S. Government Printing Office, Washington, D.C., 1932

It is not possible to compare directly the seepage tunnels to the horizontal wells driven into the reservoir except to say that seepage oil recovery is promising in reservoirs producing by gravity and containing heavy or light oil. No promising results may be expected from horizontal wells, unless a source of energy is available, or unless the oil has a low viscosity. (F. Hoffman and Water Ruehl, 1953).

Two vertical shafts about 842 feet deep intersected four oil sand beds. Two main landings were constructed at 733-foot and 812-foot levels. These landings intersected the main crosscut levels and crossed the four oil sand beds. Branch levels were turned into the intersection of each bed, both to the right and to the left. The development plan divided each bed within the mine area into blocks or panels and provided haulage ways and drainage channels for the oil.