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Oil Shale Mining Studies and Analyses of Some Potential Unconventional Uses for Oil Shale

Topical Report

H.E. McCarthy
R.L. Clayson

July 1989

Work Performed Under Cooperative Agreement: DE-FC21-86MC11076

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Western Research Institute
Laramie, Wyoming
and
Synfuels Engineering and Development, Inc.
Rifle, Colorado

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July 1989

FOREWORD

This report summarizes work performed by Synfuels Engineering & Development, Inc. under Contract 893003 issued by Western Research Institute (WRI) under DOE cooperative agreement DE-FC21-86MC11076. Engineering studies and literature review performed under this contract have resulted in improved understanding of oil shale mining costs, spent shale disposal costs, and potential unconventional uses for oil shale. The topics treated in accordance with the provisions of the Statement of Work are outlined below.

Costs of conventional mining of oil shale. A system of costs of conventional mining of oil shale for surface processing was developed. This system is described in Subsection 2.1 of the report.

Mining scenario. A minimal-scale mine, consistent with a niche market industry, was incorporated into a mine design described in Subsection 2.2 of the report.

Accelerated schedule. The benefits of mine opening on an accelerated schedule are listed in Subsection 5.2.4 and quantified through discounted cash flow return on investment (DCFROI) modelling in Subsection 5.3.

Spent shale disposal. An estimate was made of the costs of disposal of spent shale underground and on the surface. The estimates are presented in Subsection 3.2.

Resource recovery. Potential increases in resource recovery in conjunction with underground spent shale disposal were tabulated. The results of this investigation are summarized in Subsection 3.3.

Oil shale as a sulfur absorbent. The potential uses of oil shale as a sulfur absorbent in electric power generation are discussed in Subsection 4.2, reduced to inputs for DCFROI evaluation as described in Subsection 5.2.2, and evaluated for representative oil shale projects in Subsection 5.3.

Soil stabilization. The possible use of spent shale as a soil stabilizer for road bases is outlined in Subsection 4.3, quantified in Subsection 5.2.3, and evaluated for potential economic impact upon representative oil shale projects in Subsection 5.3.

Cogeneration. The feasibility of co-production of electricity and the effect of project-owned and utility-owned power generation facilities were evaluated. The concept is discussed in Subsection 4.1, adapted for DCFROI modelling as described in Subsection 5.2.1, and evaluated by means of DCFROI analysis of representative oil shale projects as reported in Subsection 5.3.

The findings and recommendations arising from the study are summarized in Section 1 and presented in more detail in Section 6.

Many individuals contributed to the data base employed in the study. We are indebted to representatives of WRI, the U.S. Bureau of Mines, Occidental Petroleum Corporation and numerous other private and public organizations. The timely contributions of individuals within these organizations are gratefully acknowledged.

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1.0 EXECUTIVE SUMMARY

Synfuels Engineering & Development, Inc. (SED) was awarded Contract 893003 by Western Research Institute (WRI) to consider oil shale mining methods and certain potential uses of oil shale and shale ash. This section summarizes the assigned tasks, methods used, and the outputs of each task.

The contract required that SED develop mining costs of conventional mining, develop a cost estimate for a mine scenario based on an oil shale industry oriented to niche-market products, investigate the effect that marketing of oil shale and shale ash would have on a project, and determine the effect of cogeneration of electricity on project economics. In performing these tasks, SED used in-house data where possible and performed new designs and studies where required.

Oil shale mining costs for room and pillar mining (R&P), open pit mining, and chamber and pillar mining were developed from in-house data and work done for DOE through Idaho National Engineering Laboratory. Insufficient data were available to obtain good estimates for chamber and pillar mining, so a new design study was completed. Data were gathered, analyzed, and put on a consistent basis. Mining details were considered.

The first phase of the study showed that scale factors for mining efforts could be developed. Open pit mining and the benching operations of a room and pillar mine were similar. The conclusion of this phase of the study was that open pit mining with more than a 1:1 overburden ratio is not competitive with room and pillar mining.

Further, the data showed that chamber and pillar mining for combined vertical modified in situ (VMIS) and surface processing offers cost advantages on a per-barrel basis. Analysis of the data showed that shortening the development schedule by using smaller capacity retorts could be advantageous to project economics. The design of the 4,797 ton/day mine to support the 2,000 bbl/day surface plant for niche-market products showed that scaling down the capital costs would yield reasonably accurate estimates; however, scaling of the operating cost would lead to costs too high by a factor of 2.5:1 to 3:1. The operating costs for a demonstration scale (2,000 bbl/day facility) were about \$5.10/ton vs. \$2.00 to \$4.00/ton for room and pillar and open pit mining. This shows the effect of operating a system in a mode consistent with the mining scale.

Market studies have shown that the use of oil shale for co-combustion with coal in power plants has significant potential. Typically, oil shale could be shipped 6 to 15 times as far as limestone and still be competitive based upon present data. This would allow a few thousand tons per day to be sold if favorable test data continue to be developed. Oil shale ash can be used as a soil stabilizer for road base; however, the market appears to be less than 500 tons per day (T/D). This is a good byproduct, but has minimal effect on economics. Cogeneration of electricity is economically attractive for all oil shale operations. This is true regardless of whether the project or a utility company owns the power plant. There is an economic advantage for a utility owned power plant, and this could reduce the maximum equity exposure for a given project. The fluid bed option considered herein is also used for SO_2 removal from produced gases.

The option of re-injecting spent shale into an oil shale mine was considered. Re-injection using current technology is not justified by project economics.

2.0 MINING

2.1 Cost of Conventional Mining

This section of the report discusses the operating and capital costs determined for conventional mining. The data for computing the mining costs were taken from commercial oil shale mine designs prepared by SED for various clients. To preserve confidentiality, the specific clients cannot be identified. Data were taken for mines which required shafts or adits. Some designs were performed for deep deposits and some for deposits where adit entries were possible. Open pit designs were done for mines with overburden ratios ranging from 1:1 up to 1.8:1. All costs were reduced to out-of-pocket (labor, maintenance materials, and operating supplies) operating costs and put on the same basis. These costs were compared for internal consistency, and discrepancies were resolved such that the values reported herein represent the best available costs. References 1 through 8 were used in this work.

2.1.1 Operating Costs

Operating costs were determined for room and pillar (R&P), chamber and pillar (C&P) for vertical modified in situ (VMIS) production and for open pit mining.

Room and Pillar. For room and pillar mines, three separate, distinct operations are evident: development, top slice mining and benching.

Some mines may not have the benching operation; however, for most of the oil shale resources a two-pass mining system would be employed. From our reference material, we were able to determine the cost of mining on a commercial scale (Table 2.1-I). These costs were computed based upon the tons mined in each operation. For example, only about 6.5% of the mined tons would come from development mining, about 53% from top slice mining, and about 40.5% from benching operations. The unit cost is made up from the total mining costs.

In order to compare these costs with other costs, we have allocated the maintenance, operating miscellaneous, surface operation, and management/engineering to the other costs to arrive at total costs for operations (Table 2.1-II). The baseline data are from numbers developed in 1982 and 1983 that are escalated to 1988 dollars. Note that the weighted cost is $2.96 per ton but benching is only about $2.10 per ton and development is $4.59 per ton.

TABLE 2.1-I
COMMERCIAL SCALE MINING COST

Mine Operation	Cost ($/ton)			
	Manpower	Material	Diesel	Total
Hoist (Prod)	0.0370	0.0093	0.0004	0.047
(Service)	0.0373	0.0013	0.0011	0.040
Development	0.9857	0.9333	0.1410	2.060
Top Slice	0.5957	0.6855	0.0865	1.370
Benching	0.4890	0.3492	0.1018	0.940
Maintenance	0.2353	0.3192	0.0059	0.560
Oper. Misc.	0.1835	0.0073	0.0102	0.200
Surface Misc.	0.0744	0.0013	0.0001	0.076
Mgmt/Engineering	0.0831	0.0009	0.0010	0.085

TABLE 2.1-II
TOTAL COST FOR OPERATIONS

Mine Operation	Cost ($/ton)		
	Cost	Cost + 10% Contingency	Cost + 31% Escalation
Production Hoist	0.0788	0.0867	0.1035
Service Hoist	0.0670	0.0737	0.0880
Development	3.491	3.840	4.585
Top Slice	2.327	2.560	3.057
Bench	1.596	1.757	2.098

Total cost weighted = $2.96 per ton

It is important to consider the effect of scale on mining operations. We evaluated a 1/4-scale mining operation to obtain this effect. Table 2.1-III shows the effect of this 1/4-scale on operating costs. Note that the operating costs are about $4.25 vs. the $2.96 for the full-scale mine. If we use this for a cost scale factor ($A(\text{scale})^p = B$ (p=cost scale factor), we arrive at p=0.75. Using this factor to scale to a demonstration scale we find a cost of about $13.32 per ton. In Subsection 2.2 we find that a design which was made specifically for a demonstration project yielded an operating cost of only $5.10 per ton. This would indicate that the difference relates to the change in operating mode from the large scale mine to the small scale mine. Note also that the demo mine did not involve hoisting, so the $4.25 would be reduced by about $.70 per ton; therefore, the escalation is from $3.55 to $5.10, which is reasonable.

TABLE 2.1-III
1/4-SCALE OPERATION

Mine Operation	Cost ($/Ton)			
	Labor	Material	Diesel	Total
Hoisting (Prod)	0.1022	0.0096	0.0012	0.1130
(Service)	0.1337	0.0054	0.0064	0.1455
Development	1.2300	0.5339	0.1760	1.940
Top Slice	0.8626	0.7080	0.1395	1.710
Benching	0.4434	0.2821	0.0578	0.7843
Maintenance	0.4062	0.3861	0.0077	0.8000
Operating Misc.	0.3567	0.0087	0.0289	0.3943
Surface Operation	0.1513	0.0028	0.0010	0.1551
Mgmt/Engineering	0.2759	0.0018	0.0011	0.2789

With Allocation of Maintenance, Operating Misc., Surface Operation & Mgmt/Engineering

	Total	+ 10% Contingency	+ 31% Escalation
Hoisting (Prod & Service)	0.523	0.576	0.687
Development	3.936	4.330	5.170
Top Slice	3.476	3.824	4.565
Benching	1.464	1.611	1.923

Weighted Cost = $4.25 per ton

Chamber & Pillar. For VMIS mining, we have the basis of the cost from room and pillar except that the amount of development work is increased and only top slice mining would occur. In addition, we must add in the cost of preparing the in situ retort (rubblizing). Therefore, we must compute the rubblizing costs and add them to the cost of the 1/4-scale mine to allow a comparison of mining costs. For rubblizing costs, we can use the same drilling rate used for room and pillar and we use ANFO as a blasting agent. From data in the in-house designs we have done for both the southern edge basin studies as well as deeper material, we find that for a 50,000 bbl/day scale drilling and blasting operation, material would cost about $17 million per year. Labor is about the same as material, so the cost per ton rubblized would be about $0.872. For a large commercial scale mine, we find the following:

Void Mined	65% of mined material		
	First Pass Mining	=	2.668 $/ton
	Hoisting	=	0.192
		=	$3.86 per ton
Development Work	35% of mined material		
	Development Mining	=	4.588
	Hoisting	=	0.192
		=	$4.77 per ton
Rubblizing	384,700 ton/retort	=	0.872 $/ton
Weighted Cost	= $6.14 per ton mined which includes the rubblizing costs		

Using the same procedure with costs from the 1/4-scale mine, an equivalent cost of $8.02 per ton is obtained.

These costs assume a 22% void mining and a four-level mine design. These can be compared directly with room and pillar mining costs. However, since we obtain more oil per ton mined from a VMIS system than from a room and pillar system, we must compare these costs on the basis of cost per barrel of oil produced. For a balanced VMIS/surface system, 60 to 65% of the oil produced is from underground and 35 to 40% is produced at the surface, so we use the 60/40 split for analysis.

For a barrel of oil from the surface using 27 gpt oil shale, we need 2.02 tons of material mined. Thus, room and pillar mining costs (large scale) = (2.96)(2.02) = $5.98/bbl. For the same 2.02 tons mined, we achieve 2.5 to 2.9 barrels of oil from a VMIS system, which makes the mining cost (6.14)(2.02)/2.5 = $4.96/bbl, which gives an advantage to the combined system.

Open Pit Mining. The literature on open pit mining is rather limited. Only two designs were available for this study. One study, which was done for a site on the southern edge of the Piceance Creek Basin, showed extremely high costs for open pit mining with a high overburden ratio of 1.87:1. Breaking this down to actual costs per ton mined for the mine at various stages of development showed costs ranging from $1.40 to $2.22 per ton of material mined. From a study in the center of the Piceance Creek area, we obtained a cost of $1.91 per ton mined. If we compare these to the benching operation of room and pillar mines without hoisting costs, we again find a cost of about $2.00 per ton ($2.10 to $1.92), so all the data show a cost of approximately $2.00 per ton. This cost applies to the overburden as well as to the oil shale itself. On an average, if we use a 1:1 overburden-to-ore ratio, we find a cost of $4.00 per ton of ore. This would vary from $6.00 to $7.00 per ton in the early stages to the $2.00 per ton in the late stages of open pit mining, but for our analysis, we can use $4.00 per ton as the average cost. Since we could see a lower average yield 22-25 gpt used for the surface process, the cost per barrel might be (2.35)(4.00) = $9.40/bbl taking dust, mining, and retorting losses into consideration. The big advantage results from increased resource recovery and a longer operation at a given site.

2.1.2 Capital Costs

The studies referred to in Subsection 2.1.1 were used to arrive at capital costs as well as operating costs. However, for VMIS mining, we had to redesign the mine and produce new, realistic capital costs. We now have a consistent set of numbers which are comparable in contingency, level of mine design, etc. We feel that these costs represent a plus or minus 25% type of estimate and would allow one to use the numbers for economic analysis with reasonable confidence. As in Subsection 2.1.1, we will discuss room and pillar, VMIS and open pit mining options.

2.1.2.1 Room and Pillar. For room and pillar mining, we used three different scales of mines. We were able to reduce the mining costs to five categories (Table 2.1-IV). We begin by using the mine design for the Cottonwood Wash study since this represents a complete design good to about plus or minus 10%.

At 17,500 tons/day (T/D), we find a capital cost at $9,019 per T/D and at 70,000 T/D the cost was about $4,342.4 per T/D. Using another study for a confidential client, the costs came out at $3832.4 per T/D. Note that if we subtract the shaft cost from the 70,000 T/D case, we arrive at $3632 per T/D. If we use this, there is reasonable agreement because of the more extensive development work required around a shaft.

If we use this to scale down to the demonstration scale mine at 4,797 T/D and use the adit mine case, we find a capital cost of $12,466 per T/D versus the Section 2.2 results of about $12,100 T/D. This is fair agreement and shows the consistency of these results. Table 2.1-IV is thus a reasonable representation of capital costs.

TABLE 2.1-IV
ROOM & PILLAR MINING COSTS

Item	Mine Production 17,500 T/D (Deep Mine) Costs $/T/D	59,000 T/D (Adit) $/T/D	70,000 T/D (Deep Mine) $/T/D
Surface Facilities	1,294.2	751.1	323.6
Shafts	2,251.3	--	710.6
Mine Development	3,133.4	1,612.8	2,227.5
Mine Equipment	1,960.9	804.4	857.4
Crushing & Screening	379.3	664.1	223.3
Total	9,019.1	3,832.4	4,342.4

Scale Factor $A(\text{Scale})^{\gamma} = B$

$\gamma = 0.47$

2.1.2.2 Chamber and Pillar (VMIS). For VMIS projects in which about 5,000,000 tons per year (T/Y) are mined, a 21-foot diameter vent shaft is adequate. Table 2.1-V shows the cost of the mine as estimated herein and shows the cost of all surface and related equipment. This gives a total of $18.551 million for the surface facilities. The shafts total $33,816 million. When we laid out the mine and computed the feet of main and development drifts, we obtained 6,471,272 tons with another 1,821,924 tons of shaft development. At $15.70 per ton for contract mining, this resulted in a cost of about $130 million. When the shops, spill ducts, storage and etc. are added, we arrive at about $136 million. With initial retort development, the development costs with 20% contingency came to $164,388 as shown in Table 2.1-V. If we add in the mining equipment at $28.767 million and primary crushing at $5.5 million, we arrive at a capital cost estimate as follows:

	Cost ($x1000)	Cost ($/T/D)
Surface Facilities	18,551	1,298.6
Shafts	33,816	2,367.1
Mine Development	164,388	11,507.2
Mine Equipment	28,767	2,013.7
Primary Crushing	5,500	385.0
	251,022	17,571.6

TABLE 2.1-V
CHAMBER AND PILLAR
MINING CAPITAL COSTS, $x1000

Cost Item	Total	Year 1	Year 2	Year 3
<u>Site Building & Surface Items</u>				
Site Grading	2,843	2,843		
Office, Dry & Warehouse	3,732	2,798	934	
Hoist Houses	464		464	
Fan Bldg, Fans & Ductwork	740			740
Access Roads	930	930		
Parking Facilities	52	52		
Man Tunnel	167		167	
Magazine & Cap Storage	80	80		
Guard House	6	6		
Fire Storage, Etc.	971	971		
Service Shaft Prep. Bldg.	283		283	
Prod. Shaft Headframe Fdns.	71		71	
Prod. Shaft Headframe	842		842	
Service Shaft Headframe Fdns.	71		71	
Service Shaft Headframe	842		842	
Ventilation Heating Coils & Structure (+10%)	439		439	
Production Hoists	1,732		1,732	
Service Hoist	1,436		1,436	
Escape Hoist	377		377	
Cages and Skips	670		425	245
Sheaves and Ropes	1,363		1,080	283
Surface Compressor & Misc.	167		167	
Subtotal Surface	18,551	7,680	9,603	1,268
<u>Shafts</u>				
Production Shaft	9,251	5,396	3,855	
Service Shaft	15,110	8,462	6,648	
Vent Shaft #1	9,455		6,303	3,152
Subtotal Shafts	33,816	13,858	16,806	3,152
<u>Underground Development</u>	164,388		32,765	131,623

Again, in terms of the mining cost ($/T/D) equivalent to surface, we would divide by 2.5 to 2.8, so using 2.5 we obtain $7,029 as compared with $9,019. This again shows the effect of the combined system. No design was completed for a larger scale mine, but we would expect the same basic result.

2.1.2.3 Open Pit Mining. For the open pit costs, we were able to analyze two studies and achieve a consistent set of numbers which allows us to understand the cost of open pit mining. In both cases, we were looking at a 40,000 to 60,000 T/D mine. Table 2.1-VI shows the data as analyzed and updated. These costs are equivalent on a basis of total tons mined but vary on an ore basis because of the difference in overburden ratio. We find this to be consistent and understandable. One can thus see the importance of the overburden ratio on both capital and operating costs.

TABLE 2.1-VI
OPEN PIT MINING CAPITAL COSTS

Mine Production Mine Costs	57,675 T/D $/T/D	40,200 T/D $/T/D
Surface Facilities	301.0	349.9
Mine Development	374.0	4098.0
Equipment	4112.0	4010.0
Crushing	240.0	399.0
	6827 on ore basis	8857 on ore basis
	3414 on total ton basis 1:1 overburden	3163 on total ton basis 1.8:1 overburden

2.2 Mine Design for Small Production Plant

This section discusses the mine design for a small production plant that would serve an oil shale industry oriented to niche-market products. An evaluation done as a part of this overall project determined that such a plant should produce 2,000 bbl/day. Assumptions made were 25.6 gpt oil shale at a site located on the southern edge of the Piceance Creek Basin. This would involve an adit mine with a surface plant located above the adits. We have chosen a typical mine location at the southern basin edge for which we have data. Due to the generality of the process and to avoid any controversy on ownership, etc., this site will be labelled Site C.

Using Site C as a generalized site, the following assumptions were made:

1) Adit entry (one or more depending on requirements)
2) Mining of sufficient shale for 2,000 bbl/day of raw shale oil
3) 20% fines production during surface grinding
4) 25.6 gpt average (actual average from Site C would be 27-28 gpt)
5) 90% oil yield
6) 5% dust loss in mining/material handling
7) 10-mile access road required for mine
8) 3-mile haul road required for transit from mine to surface
9) Truck haulage to surface from mine.

This was the design basis. The resulting design will now be discussed. The mine production was computed to be 4,797 T/D. The mine will have two main adits with three entries per adit. The mining will comprise a mining horizon of 65 feet with a 30-foot first-pass mine and a 35-foot benching operation in a panel after the first-pass mine is completed. The equipment will be rated for gassy mine conditions. The mine will consist of a 50-foot span with 50-foot pillars (Figure 2.2-1).

Since we are looking at a small production mine, we have laid out the panels so as not to preclude future expansion. One panel will last for 867.5 days of top slice mining and 1,012 days on the benching operation, so the panel will last for about 5.4 years. This changes the design such that only minimal development work will be done to arrive at the first panel; thus, if expansion were to be accomplished, more development work would be required. With the above considerations, we will use equipment which can be used for drilling - both benching and face-blasting operations. The limiting factor will be face drilling, so the amount of equipment required will be computed based on the face operation. Using 18-foot holes, we will pull 16.5 feet of rock in a blast such that we will deliver about 1683 tons/round which will require 2.85 rounds per day. When benching, we will get about 2,380 tons/round, i.e., we will need about two rounds per day.

We will operate a day shift only. We will work 10-hour shifts with two crews. The first crew will perform the production operations four days per week. Crew 2 will perform development work two days per week and production two days per week, giving six days of production augmented by development work for two days per week for future panels.

In order to show how this will work, we have computed the cycle times for all operations as follows:

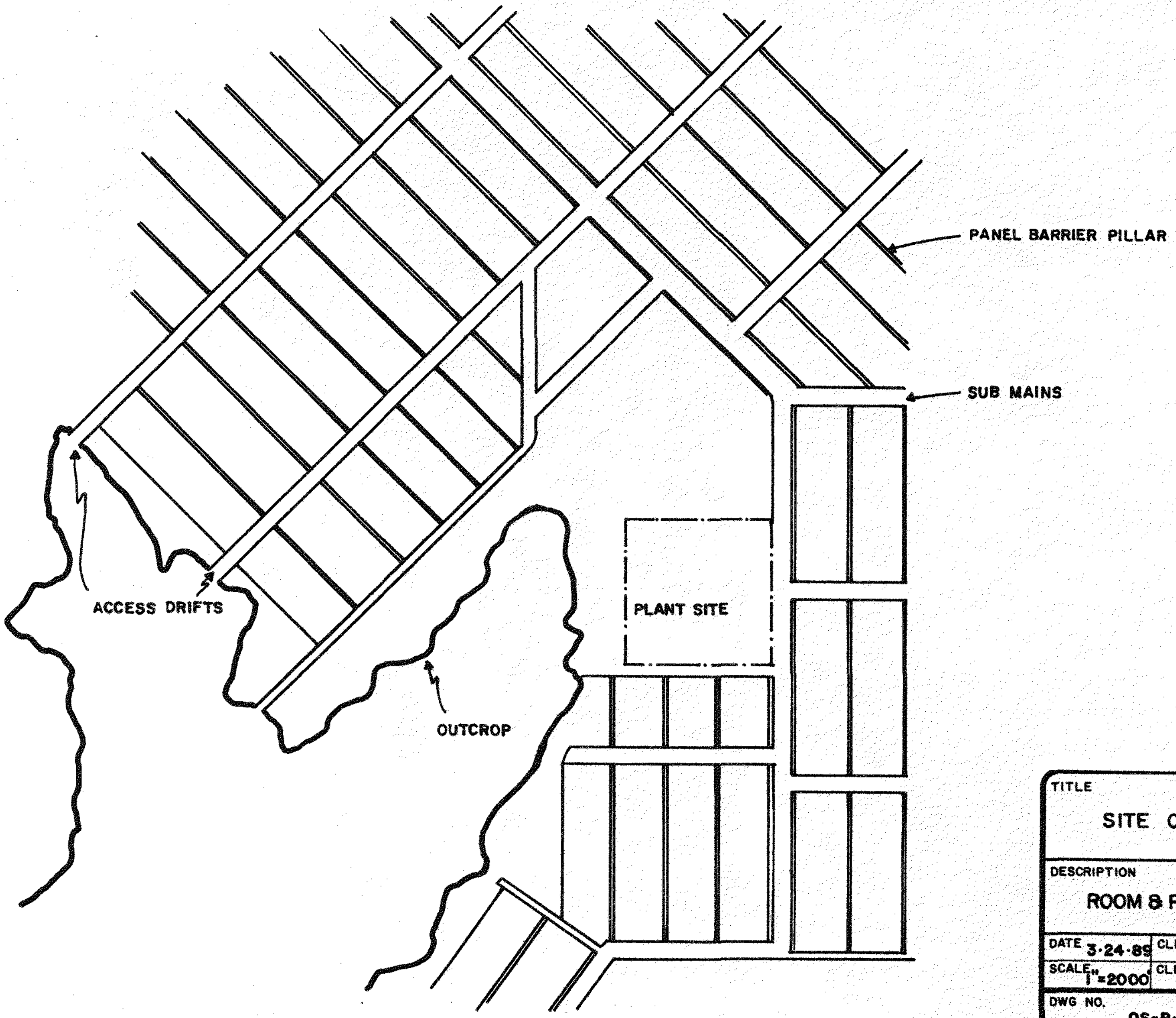


FIGURE 2.2-1A

TITLE
SITE C

DESCRIPTION
ROOM & PILLAR MINING SEQUENCE

DATE 3·24·89	CLIENT	PROJECT NO.	DESIGN BY
SCALE 1"=2000'	CLIENT APPROVAL	PROJECT MGR	DWG BY FB

DWG NO. OS-R-M-103
REVISION
SYNFUELS ENGINEERING & DEVELOPMENT, INC. RIFLE, CO SED

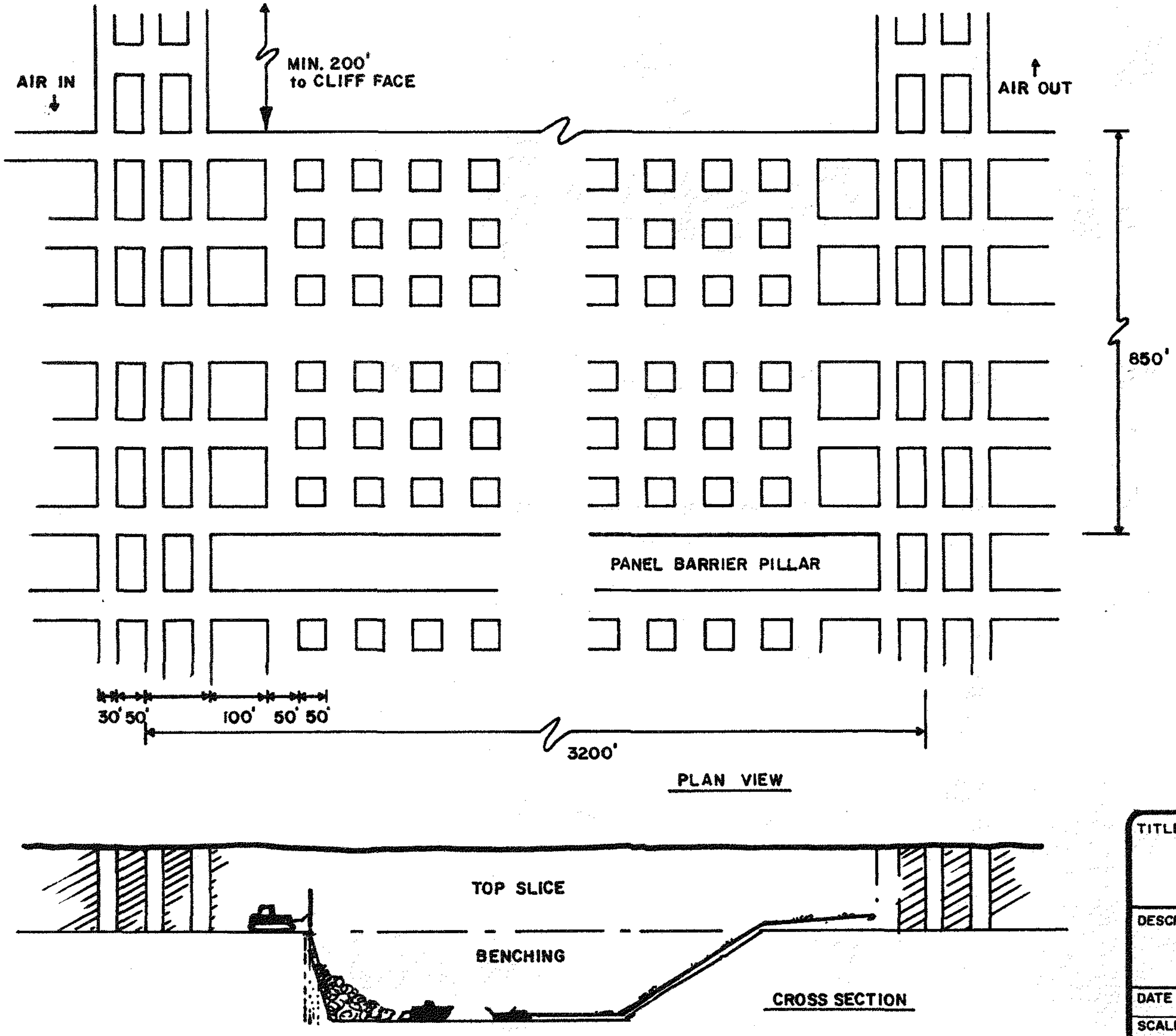


FIGURE 2.2-1B

TITLE SITE C			
DESCRIPTION ROOM & PILLAR PANEL LAYOUT			
DATE 3-24-89	CLIENT	PROJECT NO.	DESIGN BY
SCALE 1"=20'	CLIENT APPROVAL	PROJECT MGR	DWG BY FB
DWG NO. OS-RM-101		REVISION	

SYNFUELS ENGINEERING & DEVELOPMENT, INC. RIFLE, CO

Drilling Time

Set up		30 min
React, realign and collar hole	(1 min/hole x 50 holes)	50 min
Drilling Time	$\frac{18\ \text{ft/hole}}{8\ \text{ft/min/2}}$	50 min
Trimming and other delays		20 min
SUBTOTAL		150 min = 2.5 hours

Explosive Loading Cycle (50-hole round)

Face Size	30 x 50 ft
No. of Holes	50/1 round
Powder Function	1.58 lb/ton
Hole Diameter	3 inches
ANFO	2000 lb/round
Loading Rate	125 lb/min

Time

Set Up	20 min
Loading Time $\frac{2000\ \text{lb}}{125\ \text{lb/min}}$	16 min
Retract, Realign 0.5 min/hole x 50 holes	25 min
Trimming & Other Delays	40 min
Total Time	101 min = 1.68 hours so 1.75 hr/round

So, explosive loading is not limiting: drilling is limiting.

Mucking Cycle

Tons/round	1683
Bulk Density	75 lb/ft^3 26.7 ft^3/ton or 1 ton/yd

- Capacity: Cat 992 with 15.5 yd bucket
  fill factor .85
  effect .8
- Haul Time + Load Time
- (Load) = (15.5)(.85)(.8) = 10.5 ton/trip

Velocity @ 5 mile/hr for 250 ft

$$\frac{(250)(2)}{5280 \times 5} = 1.136\ \text{min/cycle}$$

so say 2 min/cycle

so we can make 30 trips/hour or 315 ton/hr
in 2.5 hours = 787.5 tons
so we need 2.14 loaders, so 2 loaders will suffice

Scaling Time	2 hours

Roof Bolting Cycle

• Bolts Type	#7 Resin-Grouted Rebar
• Hole Diameter	1 1/8 inch
• Bolt Length	6-8 ft
• Pattern	30 x 12 ft (360 ft^2)
• Number of Bolts/Round	15
• Equipment	Atlas Copco - Boltac 500 diesel
• Coverage Area	200 ft^2
• Drilling Time	

$$\frac{(8\text{ft})(15\text{ holes})}{6\text{ ft/min}} = 20\text{ min}$$

- Bolting Time

3 min/bolt x 15 — 45 min

- Set up & Delays — 30 min

Total time for 50′ wide opening = 1.58 hours (95 min)

Vent time about 1 hour — $Q = 100{,}000$ cfm

$$\text{Log}_{10}\frac{x}{x_o} = -\frac{\tau}{2.303} \times \frac{Q}{Y}$$

where x = allowable concentration = 100 ppm = 0.0001

$x_o = \dfrac{\text{total blast gases (ft}^3)}{\text{Total spare volume}}$

Q = fresh air flow

Y = Total space volume

τ = time to dilute (min)

For 2,000 lb and 3,000,000 ft^3 of space

$$\text{Log}_{10}\frac{0.0001}{\dfrac{2\text{ ft}^3/\text{lb} \times 2000\text{ lb}}{3{,}000{,}000\text{ ft}^3}} = \frac{\tau}{2.303} \times \frac{100{,}000\text{ cfm}}{3{,}000{,}000}$$

$$-1.1249 = 0.0145\tau \quad \Rightarrow \quad \tau = 77.7\text{ min or }1.3\text{ hr}$$

Look at time required for 1 heading (Hdg)

• Drilling Time	150 min.
• Explosive Loading	101 min.
• Vent Time	77 min.
• Bolting	95 min.
• Mucking	150 min.
	573 min = 9.55 Hrs

So, we need 3 round/day.

Start Drilling

Hdg 1	Hdg 2	Hdg 3	Hdg 4	
Drill (D) 150 min				
Load (L) 101 min	D 150 min			
Vent (V) 77 min	L 101 min	D 150 min		
Bolt (B) 95 min	V 77 min	L 101 min		
Muck (M) 150 min	B 95 min	V 77 min	D 150 min	D = 10
	M 150 min	B 95 min	L 101 min	L = 6.7
		M 150 min	V 77 min	
			B 95 min	
			M 150 min	

In a 10-hr shift we get 8.5 hours (510 min) of work, so we can do three rounds of drilling.

With the operations thus defined, we can design the mine. We will start two main adits approximately 3400 feet apart. One adit will be the entrance, while the other will serve as the outlet for offgas and produced materials, as well as serving as the safety outlet (Figure 2.2-1). In order to start mining, we need to mine the two three-entry mains in about 1150 feet and one submain about 3400 feet in length. This would allow complete access and installation of conveyors. In addition, we would need to mine the warehouse and shop areas. We would mine cross cuts every 100 feet. For the main, this would amount to 9.66×10^6 ft^3. Sub-mains would be 5.67×10^6 ft^3 or a total of 1.833×10^7 ft^3. This translates to 1.25×10^6 tons at $15.70 per ton or $19.625 million.

In order to accomplish the mining, we would need equipment as shown on Table 2.2-I. This would allow one crew on production with another crew on development work. It would allow efficient use of manpower; however, equipment would be idle part of the time. In general, spares are provided only for critical equipment. The total equipment cost is estimated to be $21,219,000 as shown in Table 2.2-I.

In order to finish the estimate we have assumed ten miles of road to the mine site (Figure 2.2-2). This road would have to meet MSHA requirements with a berm. The cost of such a road would vary between $200,000 and $400,000 per mile. We used $300,000 per mile in our calculations. In addition, we would need about three miles of haul road to the surface plant. Since this would have to go through the rim, the road would be about twice as expensive so a figure of $600,000 per mile was used. In addition, a mine platform (500 feet by 500 feet) would be required. At $1.50 per yard removal with an average depth of 100 feet, this would amount to 1,851,852 yards or $2.778 million. The total capital cost for the mine (Table 2.2-II) is estimated at $58 million.

TABLE 2.2-I
EQUIPMENT LIST

	HP	Spare	Cost ($x1000)
Underground			
2 Drill Jumbos - 2 boom hydraulic rotary diesel		1	1,785
4 Load Haul Dumps (LHD) - Cat 992 15.5 yd^3	690	1	3,650
2 ANFO Loaders - Elec. with diesel for trimming		1	600
1 Scaler - hydraulic, diesel		1	380
2 Roof Bolters - hydraulic, diesel		1	1,200
1 Feeder Breaker - hydraulic/electric	300	-	570
1 Extensible Conveyor	125	-	1,480
1 Main Conveyor	500	-	1,945
1 Inclined Conveyor/Breaker	3700	-	3,102
1 D8 Cat. Bulldozer		-	285
1 Motor Grader		-	120
1 Supply Vehicle			50
1 Service Vehicle			75
1 Personnel Carrier			65
1 Supervisor's Vehicle			15
1 Lube Truck			90
1 Utility Truck			45
5 Auxiliary Fans			38
Vent. Lines - 3,000 ft			18
Water Lines - 5,000 ft			16
Pumps & piping			100
2 Hand Drills			10
1 Utility LHD			175
Safety Equipment			15
1 Electromagnet			9
Underground Work Shop			150
Powder and Cap Storage			75
Electrical System			40
Telephone Page			25
Automatic Controls & Alarms			25
Fire Protection Equipment			150
Water Truck			50
Miscellaneous Other Equipment (10%)			1,635
Subtotal			17,988
Surface			
1 Loader			320
1 Ambulance			35
1 Forklift (5-ton)			90
1 Crane			137
2 Pickup Trucks			35
1 Utility/Repair Truck			35
2 Ventilation Fans (650,000 cfm each)			440
3 100-ton Trucks			210
Subtotal			1,302
10% Equipment Contingency			1,929
TOTAL			$21,219

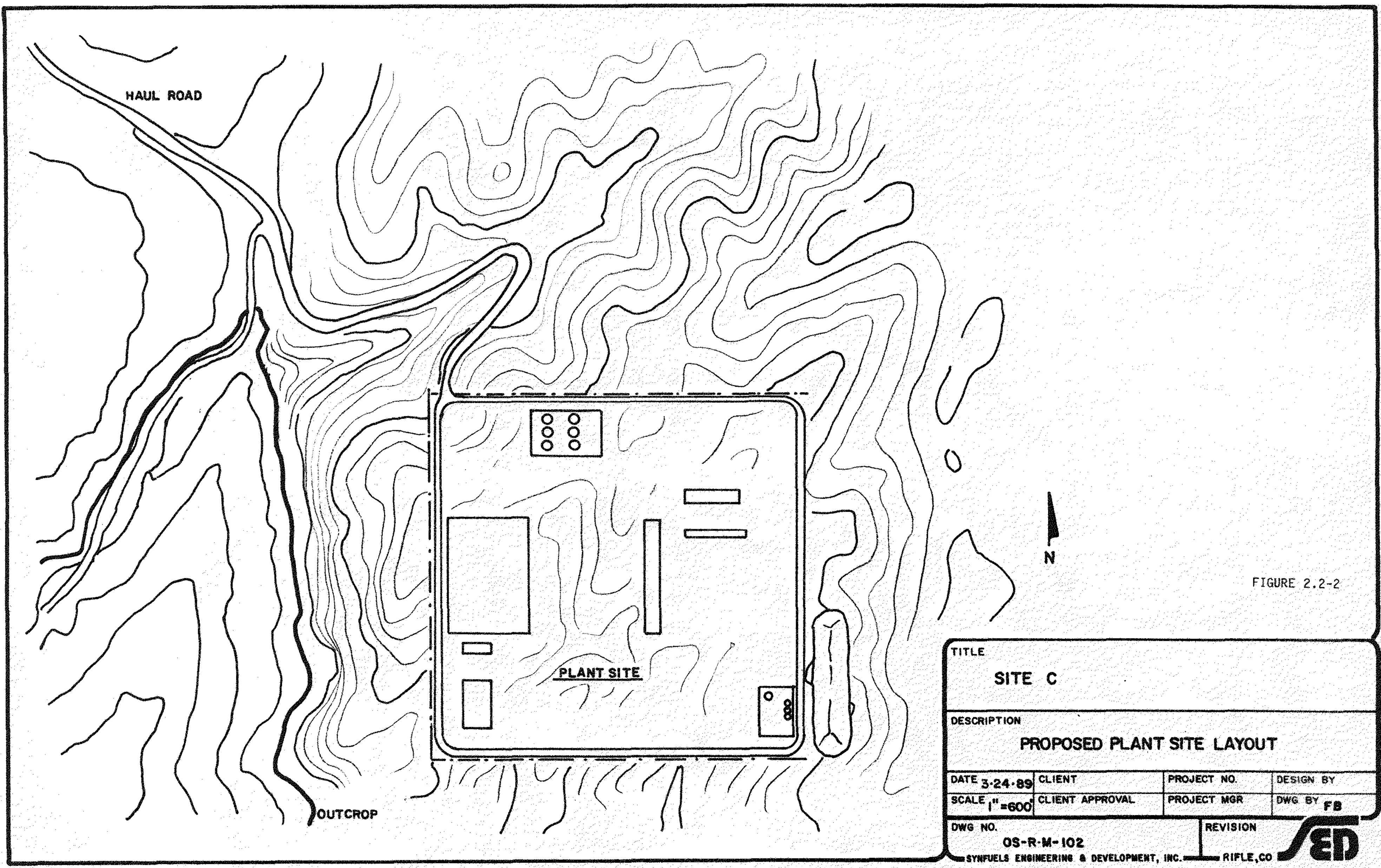


FIGURE 2.2-2

TITLE
SITE C

DESCRIPTION
PROPOSED PLANT SITE LAYOUT

DATE 3·24·89
CLIENT
PROJECT NO.
DESIGN BY
SCALE 1" =600'
CLIENT APPROVAL
PROJECT MGR
DWG BY FB
DWG NO. OS-R-M-102
REVISION

SYNFUELS ENGINEERING & DEVELOPMENT, INC. RIFLE,CO

TABLE 2.2-II
CAPITAL COST SUMMARY

		$x1000
Mine Development	1.25 x 10^6 tons @ $15.70/ton	19,625
Equipment		21,219
Site Prep (Mine & Roads to Mine and Surface)		
Access Road	10 miles @ 300,000 per mile	3,000
Road to Surface	3 miles @ 600,000 per mile	1,800
Mine Access Platform	500 x 500	2,778
		7,578
Shop		2,000
Portals		incl.
Warehouse		incl.
Buildings		132
		2,132
	TOTAL	50,554
	15% contingency	7,583
	TOTAL	$58,137

Given the design and capital costs, we now must look at the operating and maintenance costs. Labor will be the largest component of this cost, so we will describe this in some detail. Table 2.2-III gives the detail of the labor cost required. This shows a total labor cost of $4,699,222 per year. Wages are comparable to those paid in today's market in Colorado. As shown, total labor costs amount to $2.80 per ton ($6.71 per bbl). The mine is somewhat inefficient at only 61 tons mined/shift.

Table 2.2-IV shows other operating costs. As shown, we used 45% of salary as fringe benefits, 5% of capital cost for maintenance materials and incidentals at 10% of labor and operating supplies. The total cost included development, top slice, and benching operations. The annual operating cost is about $8.5 million or $5.09 per ton. This is compared to the $3.00 to $4.00 per ton shown in Subsection 2.1.

TABLE 2.2-III. MANNING TABLE
(Room and Pillar)

Job Classification	Total Employees (2 crews)	Wages ($/hr)	Total Salary/Wages ($/day)	($/yr)
<u>Supervision:</u>				
Mine Manager/Super	1	--	--	60,000
General Maint. Supt.	1	--	--	47,700
Electrical Supt.	1	--	--	41,800
Mechanical Supt.	1	--	--	41,800
Chief Engineer	1	--	--	41,800
Shift Foreman	1	--	--	39,690
Safety Director	1	--	--	37,800
Foreman Maintenance	1	--	--	30,600
Training Officer	1	--	--	37,600
Safety Inspector	1	--	--	30,600
Draftsman	1	--	--	27,500
Surveyor	1	--	--	27,720
Surveyor Assistant	1	--	--	23,940
Warehouse Man	2	--	--	46,200
Purchasing Agent	1	--	--	24,150
Chief Clerk	1	--	--	25,200
Secretary	1	--	--	15,500
Security	8	--	--	137,800
Medic	1	--	--	21,000
Subtotal	27			788,400
<u>Production Development:</u>				
Jumbo Drill Operator	2	14.00	--	58,240
Drill Helper	2	11.25	--	46,800
LHD's Operator	4	13.50	--	112,320
Blasting Man	2	12.00	--	49,920
Blasting Helper	2	11.25	--	46,800
Scaler Operator	1	13.50	--	28,080
Roof Bolter	2	13.50	--	56,160
Roof Bolter Helper	2	11.25	--	46,800
Feeder Breaker and Conveyor Operator	1	11.25	--	23,400
Service Man	2	11.75	--	24,440
Helper	2	10.25	--	42,640
Subtotal	22			535,600

TABLE 2.2-III. MANNING TABLE (CONT.)

Job Classification	Total Employees (2 crews)	Wages ($/hr)	Total Salary/Wages ($/day)	Total Salary/Wages ($/yr)
Operating Misc.:				
Grader Operator	1	13.50	--	28,080
Dozer Operator	1	13.50	--	28,080
Carrier Operator	1	11.75	--	24,440
Water Truck Operator	1	11.75	--	24,440
Utility LHD's Operator	1	13.10	--	27,248
Pipe Man	2	10.25	--	42,640
Conveyor Man	1	10.25	--	21,320
Ventilation Man	2	10.25	--	42,640
General Helper	2	10.25	--	42,640
Subtotal	12			281,528
Maintenance:				
Underground Electrical				
Electrician	2	13.25	--	55,120
Helper	2	10.25	--	42,640
Surface Electrical				
Electrician	2	13.25	--	55,120
Helper	2	10.25	--	42,640
Subtotal	8			195,520
Underground Mechanical				
Mechanic	6	13.25	--	165,360
Oiler	2	10.25	--	42,640
Welder	2	13.75	--	57,200
Machinist	1	12.00	--	24,960
Helper	1	10.25	--	21,320
Subtotal	12			311,480
Surface Mechanical				
Mechanic	6	13.25	--	165,360
Oiler	2	10.25	--	42,640
Welder	2	13.75	--	57,200
Machinist	1	12.00	--	24,960
Helper	1	10.25	--	21,320
Subtotal	12			311,480

TABLE 2.2-III. MANNING TABLE (CONT.)

Job Classification	Total Employees (2 crews)	Wages ($/hr)	Total Salary/Wages	
			($/day)	($/yr)
<u>Surface Operations</u>:				
Truck Operator	3	11.25	--	70,200
Crane Operator	1	13.50	--	28,080
Ambulance Operator	1	11.25	--	23,400
Fireman	1	11.00	--	22,880
Service Man	2	11.25	--	46,800
Janitor	1	10.00	--	20,800
Labor & Trainee	1	8.25	--	17,680
Subtotal	10			206,440
Total labor	103			2,630,554
10% contingency				263,055
Administration (12% of labor cost)				347,233
Subtotal				3,240,843
Fringe Benefits @ 45%				1,458,379
TOTAL LABOR COST PER YEAR				4,699,222

Total Labor Cost per Ton of Shale Mined:

$$\frac{4,699,222}{4797 \times 350 \text{ dpy}} = 2.80$$

Total Labor Cost per Barrel Shale Oil:

$$\frac{4,699,222}{2000 \text{ bpd} \times 350 \text{ dpy}} = 6.71$$

Total tons per shift:

$$\frac{4797 \times 350 \text{ dpy}}{103 \text{ employees} \times 260 \text{ shift/yr}} = 63$$

TABLE 2.2-IV. ANNUAL MINE OPERATING COST BREAKDOWN
(Room and Pillar)

ITEM	$ TOTAL	$/ton MINED
Direct Cost:		
1. Labor		
Mining	1,126,043	0.671
Maintenance labor	900,327	0.536
Supervision	867,240	0.517
Administration	347,233	0.207
Subtotal	3,240,843	1.931
2. Fringe benefits @ 45% of labor	1,458,379	0.869
Subtotal (Items 1 & 2)	4,699,222	2.800
3. Maintenance material @ 5% of capital equipment	1,060,000	0.625
4. Operating supplies		
Drilling & blasting	335,790	0.200
Material handling, mucking, crushing & hauling	335,790	0.20
Roof bolting	251,843	0.15
Equipment supplies & parts	167,895	0.10
Subtotal	1,091,318	0.65
5. Energy		
Fuel & lubricant	419,700	0.25
Power	503,685	0.30
Subtotal	923,385	0.55
Subtotal (Items 3, 4 & 5)	3,074,703	1.825
TOTAL DIRECT COSTS	7,773,925	4.62

TABLE 2.2-IV. ANNUAL MINE OPERATING COST BREAKDOWN
(Room & Pillar Cont.)

ITEM	$ TOTAL	$/ton MINED
6. Indirect cost (engineering, management and other project costs) @ 10% of labor & operating supplies	777,393	0.462
TOTAL DIRECT & INDIRECT COSTS	8,551,318	5.09

Total Yearly Operating Costs	$8,551,318
Total Operating Costs per Ton of Shale Mined	$5.09
Total Operating Costs per Barrel Shale Oil	$12.20

3.0 SPENT SHALE DISPOSAL AND RESOURCE RECOVERY

3.1 Introduction

The economic analyses discussed elsewhere in this report all assume surface disposal of spent shale. Surface disposal can be compared with underground disposal (backfilling) using a number of criteria, e.g., economic, environmental (scenic values, wildlife habitat, water quality, air quality, subsidence, etc.), and total resource recovery. As demonstrated in Subsection 3.2, cash flow analyses that consider only capital and operating costs strongly favor surface disposal. This has been found repeatedly, and the cost updating reported herein indicates that the ranking remains unchanged.

Other factors remaining equal, the introduction of resource-conversion considerations tends to make underground disposal more nearly competitive with surface disposal. However, if discounted cash flow return on investment (DCFROI) is used as the dominant criterion in economic analysis, surface disposal still emerges as the clear choice because its lower capital costs greatly outweigh the DCFROI increment obtainable from extra years of production at the end of a typical project's life cycle. This subject is treated in Subsection 3.3.

It is possible that a more complete evaluation, which would include quantification of environmental and socioeconomic factors in addition to design optimization built around the backfilling concept, could result in altered perceptions regarding spent shale disposal and recovery. However, such an evaluation is beyond the scope of the present study.

3.2 Disposal Costs

Underground disposal of spent shale can be accomplished by several methods. These include various combinations of mechanical, hydraulic, and pneumatic transport and stowing elements. However, each of these methods simply reduces - not eliminates - the requirement for surface disposal. Depending upon the type of mine, cost tradeoffs involving compaction, etc., 70 to 85 percent of the spent shale could be re-injected into the mine, with the remainder being disposed of on the surface. Thus, the objective of this part of the study was to make a cost comparison between two spent shale disposal methods for a representative commercial-sized oil shale plant which uses current technology. The underground option is a combined disposal method with about three parts re-injected to one part disposed of on the surface. The surface option uses the same technology for surface disposal as does the underground option, but under the surface option all of the spent shale is conveyed to a nearby disposal site, contoured and compacted, and revegetated.

For comparative purposes, a 50,000-bbl/day project in which all shale oil production is from surface retorts was used as a representative case. Such a project is probably near the high end of the scale in terms of the probable size of any near-term commercial oil shale development. Both surface and underground disposal benefit from economies of scale, so the per-unit costs presented herein for each option are considerably lower than those which would be incurred by smaller projects.

The system selected for defining the costs of the "underground" option is approximately that contained in reference 9. The disposal plan envisions the use of conveyors to move the spent shale from the retort outlet to the mouth of a large vertical borehole. Cooled spent shale flows downward by gravity into a hopper and from there onto a large conveyor (belt feeder) at a controlled rate and under controlled conditions. The material is conveyed by extensible conveyors into the area to be backfilled. Final top-filling is done as the conveyor retreats from the partially filled area. The material is levelled and compacted. Final filling to roof level is done by modified loaders.

The results of the cost survey for this concept are summarized in Table 3.2-I. Twenty years of full operation are used as the basis for computing per-unit costs of capital and operation. The results are in constant dollars (no inflation rate) as of the end of 1987, which is the latest period for which adequate published data were available.

A notable feature of Table 3.2-I is that estimated capital and operating per-unit costs for the backfilling option are almost twice those of the surface-disposal option. Thus, although Table 3.2-I excludes any consideration of the time value of money, it is obvious that the ranking of the two options would be unaffected by selection of discount rate.

TABLE 3.2-I
SUMMARY OF BACKFILLING OPTION

	Backfilling		100% Surface Disposal	
	$\$ \times 10^3$	$/ton	$\$ \times 10^3$	$/ton
Capital	88,214	0.1782	45,337	0.0916
Operating	414,022	0.8363	212,485	0.4292
Total	502,236	1.0145	257,822	0.5208

3.3 Resource Recovery

Several technical, economic, and regulatory factors determine what percentage of the oil shale resource can and would be mined by a given oil shale project. Within the oil shale region, the depth of the mine might vary from near-surface for a few potential projects to more than 2,000 feet for several others. For deep mines, safety considerations require that large pillars be left in place. However, the stabilizing effect of backfilling permits the use of relatively thin pillars in the mining areas. The following discussion covers the potential impact of backfilling on resource recovery and the possible effect that backfilling could have on the commercialization of oil shale.

Oil shale mining plans typically show a safety factor of 2.5 to 3.5 for the barrier pillars. The USGS report from the Conservation Division used a safety factor of 2.5. Reference 10 identified a safety factor for pillars of 2.2 as being required for mining without backfill. The same source gives a minimum factor as 1.2 with backfilling, based upon the contribution to stability from the compacted backfilled material. Based upon the direct Stream analysis method (reference 11) the governing equations are:

$$\text{Pillar Load} = G_1 = \frac{146}{144} (D) \left(\frac{(W+S)^2}{W^2}\right) \tag{1}$$

$$\text{Pillar Strength} = G_p = \frac{S_c}{F_s} \left(0.778 + 0.222\frac{W}{H}\right) \tag{2}$$

where:

W = Pillar Width, ft
S = Span, ft
D = Depth, ft
S_c = Compressive strength in rock, psi
F_s = Safety Factor

For design: $G_1 = G_p$

From equations 1 and 2 we obtain the following cubic equation:

$$\frac{.222}{H} (S_c)(W^3) + (.778S_c - 1.01DF_s)W^2 - 2.02(S)(W)DF_s - (1.01\ DF_s)S^2 = 0 \tag{3}$$

When given the compressive strength, the span, the depth and the safety factor we can compute the pillar width.

For a room and pillar mine, the recovery within the mining panels can then be computed from the following:

$$\text{Recovery} = \frac{(W + S)^2 - W^2}{(W + S)^2} = \frac{2WS + S^2}{W^2 + 2WS + S^2} \tag{4}$$

For comparative purposes, we use the following values as typical for potential oil shale projects in the western oil shale area:

$S = 40$, $H = 50$, $S_c = 12{,}500$.

Substituting these values in equations 3 and 4, we obtain the following:

$$54.949W^3 + (9.6285 \times 10^3 - DF_s)W^2 - 80DF_sW - 1600DF_s = 0 \tag{5}$$

and

$$R = \frac{80W + 1600}{W^2 + 80W + 1600} \tag{6}$$

Using this equation we can compute the effect of the safety factor on resource recovery. Table 3.3-I shows the computation for W for the safety factors from 2.0 to 4.0. This data is also displayed on Figure 3.3-1, to which the two curves of special interest (safety factors of 1.2 and 2.2) have been added.

Figure 3.3-1 can be used in conjunction with equation 6 to compute the added resource recovery obtainable through backfilling for room and pillar mining at any given depth once the safety factors appropriate to the conventional mine and the backfilled mines are established. Table 3.3-II employs the above-listed safety factors of 2.2 and 1.2 and the assumption of sufficient resource for a 20-year operation using only surface disposal to illustrate the impact of backfilling on resource recovery within the mining panels.

The added resource recovery obtainable through backfilling, which becomes more significant as the mining depth increases, is achieved at the cost of significantly increased capital and operating expenses as illustrated in Subsection 3.2. This tradeoff is evaluated for a single case in Section 5.0. The results are consistent with previous findings: if return on investment is the selection criterion, and if the effect of added resource recovery is simply to extend the operational life of the project, backfilling using current technology is not economically justified.

TABLE 3.3-I
COMPUTATION OF REQUIRED PILLAR WIDTH UNDER SAMPLE CONDITIONS

$$12{,}376\ (.778 + 4.44 \times 10^{-3}W) = (D)(FS) \qquad \left(\frac{W^2 + 2WS + S^2}{W^2}\right)$$

$$12{,}376\ (.778\ W^2 + 4.44 \times 10^{-3}\ W^3) = (D)(FS) \qquad [W^2 + 80W = 1600]$$

$$9.629 \times 10^3\ W^2 + 5.4949 \times 10^1\ W^3 = (D)(FS)[W^2 + 80W + 1600]$$

$$54.949\ W^3 + [9.6285 \times 10^3 - (D)(12S)]\ W^2 - (80)(0)(FS)W - 1600\ (D)(FS)$$

$$A_3\ W^3 \quad + \quad A_2\ W^2 \quad + \quad A_1\ W \quad + \quad A_0 \quad = \quad 0$$

FS	D	A_3	A_2	A_1	A_0	W
2.0	500	54.949	8.6285×10^3	-8.0×10^4	-1.6×10^6	17.7
	1000	54.949	7.6285×10^3	-1.6×10^5	-3.2×10^6	29.2
	1500	54.949	6.6285×10^3	-2.4×10^5	-4.8×10^6	40.5
	2000	54.949	5.6285×10^3	-3.2×10^5	-6.4×10^6	52.1
	2500	54.949	4.6285×10^3	-4.0×10^5	-8.0×10^6	64.3
	3000	54.949	3.6285×10^3	-4.8×10^5	-9.6×10^6	77.0
2.5	500	54.949	8.3788×10^3	-1.0×10^5	-2.0×10^6	20.7
	1000	54.949	8.3788×10^3	-2.0×10^5	-4.0×10^6	34.8
	1500	54.949	5.8785×10^3	-3.0×10^5	-6.0×10^6	49.2
	2000	54.949	4.6285×10^3	-4.0×10^5	-8.0×10^6	64.3
	2500	54.949	3.3785×10^3	-5.0×10^5	-10.0×10^6	80.2
	3000	54.949	2.1285×10^3	-6.0×10^5	-12.0×10^6	97.0
3.0	500	54.949	8.1285×10^3	-1.2×10^5	-2.4×10^6	23.6
	1000	54.949	6.6285×10^3	-2.4×10^5	-4.8×10^6	40.5
	1500	54.949	5.1285×10^3	-3.6×10^5	-7.2×10^6	58.1
	2000	54.949	3.6285×10^3	-4.8×10^5	-9.6×10^6	77.0
	2500	54.949	2.1285×10^3	-6.0×10^5	-12.0×10^6	97.0
	3000	54.949	0.6285×10^3	-7.2×10^5	-14.8×10^6	118.4
3.5	500	54.949	7.8785×10^3	-1.4×10^5	-2.8×10^6	26.4
	1000	54.949	6.1285×10^3	-2.8×10^5	-5.6×10^6	46.3
	1500	54.949	4.3785×10^3	-4.2×10^5	-8.4×10^6	67.4
	2000	54.949	2.6285×10^3	-6.6×10^5	-13.2×10^6	98.6
	2500	54.949	0.8785×10^3	-8.0×10^5	-16.0×10^6	122.4
	3000	54.949	-2.6215×10^3	-9.4×10^5	-18.8×10^6	164.4
4.0	500	54.949	7.6285×10^3	-1.6×10^5	-3.2×10^6	29.2
	1000	54.949	5.6285×10^3	-3.2×10^5	-6.4×10^6	52.1
	1500	54.949	3.6285×10^3	-4.8×10^5	-9.6×10^6	77.0
	2000	54.949	1.6285×10^3	-6.4×10^5	-12.8×10^6	104.0
	2500	54.949	-0.3715×10^3	-8.0×10^5	-16.0×10^6	132.8
	3000	54.949	-2.3715×10^3	-9.6×10^5	-19.2×10^6	163.3

Figure 3.3-1
Effect of Safety Factor Reduction on Pillar Width

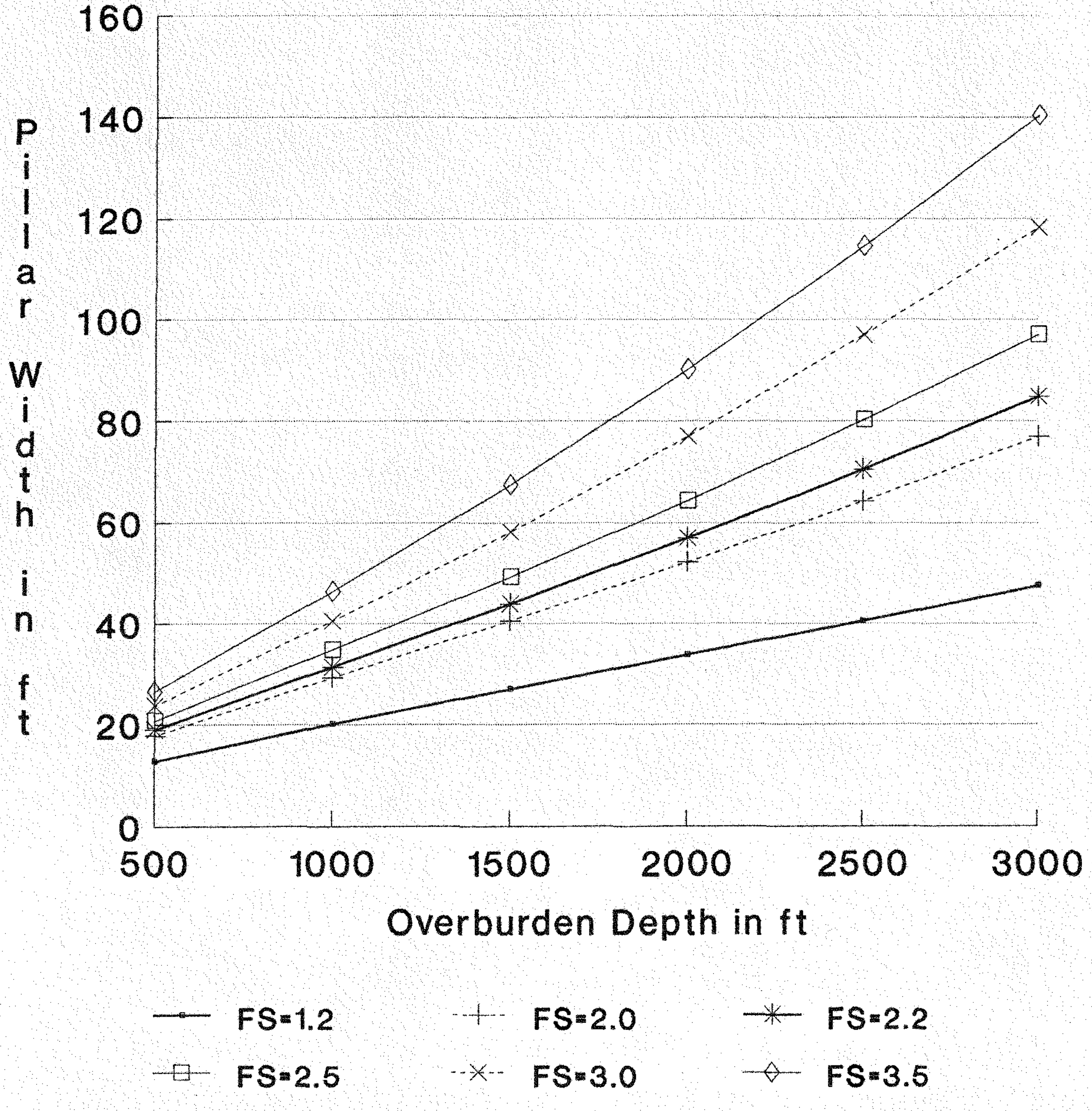


TABLE 3.3-II

EFFECT OF BACKFILLING ON RESOURCE RECOVERY UNDER SAMPLE CONDITIONS

Depth of Mine, ft	Required Pillar Width, ft		Resource Recovery %	
	Without Backfilling	With Backfilling	Without Backfilling	With Backfilling
500	18.9	12.7	89.7	94.2
1000	31.4	20.1	80.7	88.8
1500	43.9	26.9	72.6	83.8
2000	56.9	33.7	65.5	79.1
2500	70.5	40.5	59.3	74.7
3000	84.8	47.4	53.8	70.6

4.0 UNCONVENTIONAL USES FOR OIL SHALE

Historically, oil shale has been used for many purposes in many lands. In recent times, attention has been centered on the production of shale oil as a synthetic crude oil. A secondary consideration has been the potential use of spent shale, less for its value as a byproduct than as a means of reducing or eliminating disposal costs and the environmental impacts of spent shale disposal.

However, starting with the public meetings held in northwestern Colorado that led to its inception, the Oil Shale Action Committee has adopted the broader view that unconventional uses of both raw and spent shale should be thoroughly investigated because of their potentially significant contribution to commercial development of our nation's vast oil shale resource. One outcome of this interest was the inclusion in the Statement of Work of the requirement that SED consider the feasibility of co-production of electricity and potential uses of spent shale, including its potential for use as a sulfur absorbent and possible use of spent shale as a soil stabilizer or cement additive for road bases.

This section of the report introduces these three main categories (cogeneration in Subsection 4.1, sulfur removal in Subsection 4.2, and soil stabilization in Subsection 4.3), summarizes our survey of the potential market for these unconventional uses of oil shale, and gives some of the advantages and disadvantages of these applications. These discussions set the stage for the economic analyses described in Section 5.

4.1 Cogeneration

Many oil shale project plans have called for the disposal of the shale fines created during mining (perhaps 20% of the total amount mined by weight) as waste because of the problems associated with retorting such material. Also, most designs have contemplated the use of expensive sulfur control methods which have not been proven to be effective on oil shale plant emissions. Because of the obvious inefficiencies associated with such plans, recent interest has centered on the potential use of oil shale fines and offgases as sources of energy for plant operations and the production of export power, as well as the potential use of oil shale for sulfur removal. This subsection treats only the cogeneration potential associated with oil shale projects, whereas Subsection 4.2 treats the related potential for sulfur removal.

A cogeneration facility located at an oil shale project site can benefit from several advantages compared with construction of a new, conventional power plant. The fuel for the cogeneration facility, being essentially a byproduct of the oil shale operation, can be priced so as to have a competitive advantage over a conventional fuel. Fuel transportation costs can be avoided. Most of the permitting, socioeconomic, disposal, right-of-way, site preparation, administrative facility, and similar costs can be borne by the oil shale operation or shared in such a fashion as to ensure the competitiveness of the cogeneration facility. Planned additions to our total generating capacity through 1997 total 45,763 megawatts (mw), of which 19,388 mw will come from coal-fired plants (reference 12).

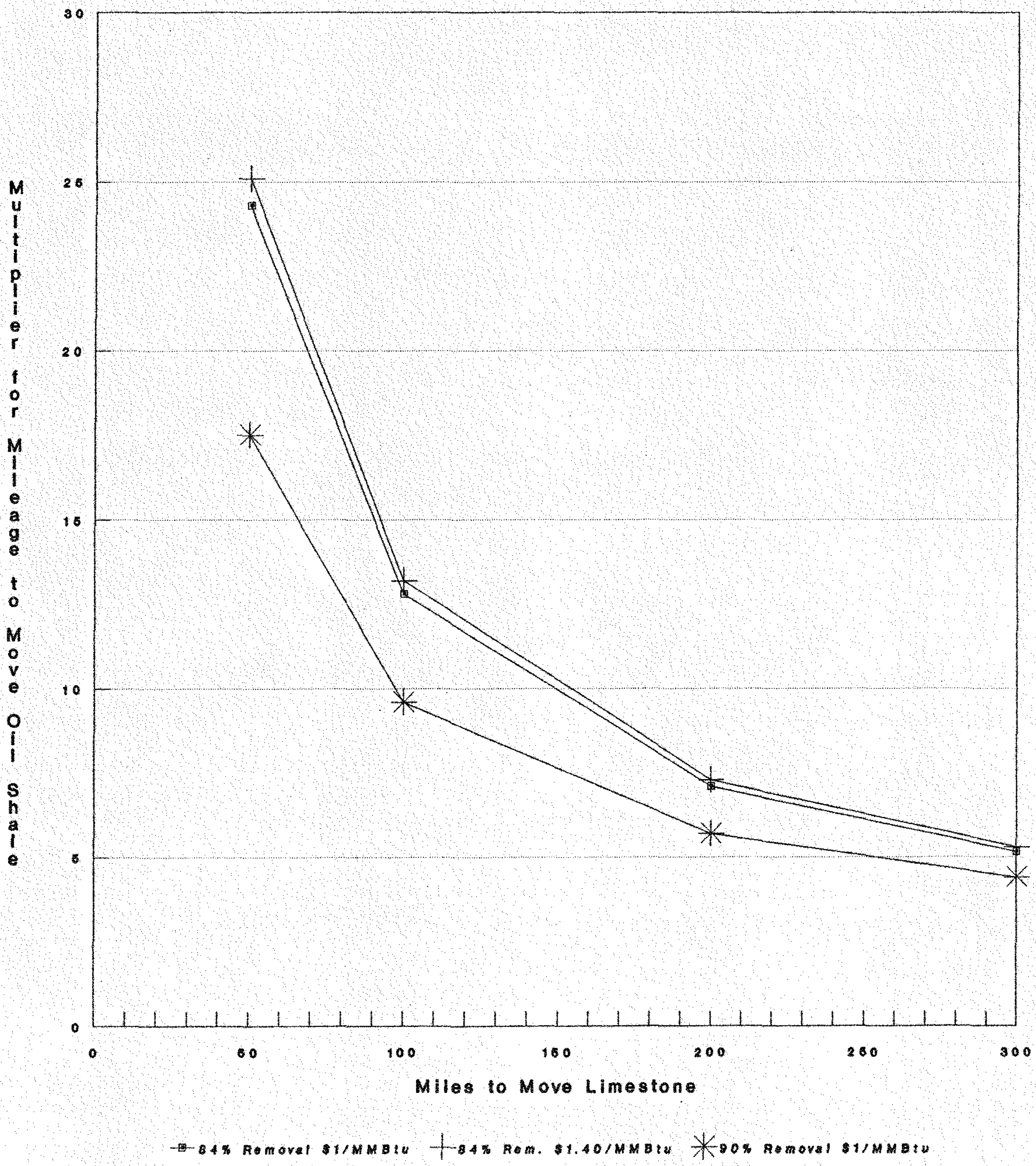
Given that a typical oil shale project might produce from 50 to 150 mw of export power, it is apparent that oil shale cogeneration facilities could satisfy only a small fraction of the anticipated demand. Thus, the degree of market penetration would depend upon factors such as economic competitiveness, security of fuel supply, and various intangibles. To overcome the intangible obstacles, the oil shale project operator may need to provide added incentives. For the representative cases considered in Section 5, financial incentives are provided to the degree suggested by past experience as being necessary.

4.2 Sulfur Removal

Oil shale appears to be economically competitive with limestone as a sulfur absorbent over distances of at least 700 miles from the western oil shale source. This implies that a conservative limit on the potential market for this application of oil shale can be set by tabulating the capacity of the coal-fired power plants within a radius of 700 miles centered on the western portion of the Piceance Basin in Colorado. Such a radius embraces all or parts of 18 states and small parts of Canada and Mexico. To be conservative, we can assume that actual highway/railway distances and intangible factors reduce the competitive radius by one-fourth, i.e., to 525 miles. Then, from data in references 12 and 13, target power generating facilities exist in ten states (excluding small portions of the Dakotas, Oklahoma, and Texas).

The distance limestone must be shipped to the site of the power plant varies from a few miles to up to 200 miles in the oil shale region. Figure 4.2-1 was developed from the cost of limestone delivered to two power plants and computing the cost per ton delivered given distances (reference 19). Taking the locations of the known sources of lime and the locations of the power plants in the region of interest, we can apply the tradeoff curves given in Figure 4.2-1 to find the approximate capacity (in megawatts) for which oil shale would appear to have a competitive advantage as a function of the type of oil shale, sulfur removal efficiency, and price charged for energy. For example, if we use the curve labelled 84% removal $1.00/MMBtu (i.e., removal of 84% of the sulfur in the offgas and energy credit of $1.00 per million Btu), we find that a plant located about 25 miles northwest of Rifle, CO would have a competitive advantage over limestone at fossil-fired plants having a total capacity of 24,238 mw. This case is summarized in Table 4.2-I. The table also uses absorbent-consumption factors to indicate a theoretical demand of up to 36,357 tons per day of oil shale as a sulfur absorbent.

Figure 4.2-1
Limestone versus Oil Shale
as a Sulfur Absorbent



Low Grade Oil Shale
with Energy Credit

TABLE 4.2-I

THEORETICAL MARKET FOR OIL SHALE AS A SULFUR ABSORBENT

State	Fossil Steam Capacity within Radius of Interest, mw	Fossil Steam Capacity with Oil Shale Competitive Advantage, mw	Theoretical Maximum Oil Shale Market, tons/day
Colorado	5,486	5,486	8,229
Idaho	0	0	0
Kansas	1,019	711	1,067
Nebraska	1,965	1,854	2,781
New Mexico	4,451	4,218	6,327
Utah	4,654	4,342	6,513
Others (AZ, MT, NV, WY)	14,991	7,627	11,441
TOTALS	32,566	24,238	36,357

These numbers provide an indication of a significant potential market, but they greatly exceed the likely opportunity or need for oil shale as a sulfur absorbent. They do not consider the percentage of fossil steam plants currently operating on natural gas, petroleum, refuse, etc. rather than coal (33.3 % nationally at the beginning of 1988 according to reference 12); they assume continuous operation at full capacity; they do not consider projected increases in electric power generation capacity; they do not consider potential regulatory changes; they do not consider the procedural inertia which any new application must face; and they assume that current test results will be generalized and substantiated by subsequent experience.

For evaluation purposes, we assumed that each commercial oil shale facility could secure a contract to supply at least one 400-mw power plant with oil shale for use as a sulfur absorbent. This would create a demand for up to 603 tons per day for the facility. To be conservative, we used 500 tons per day in the analyses reported in Section 5.

4.3 Soil Stabilization

Oil shale is a kerogen-bearing, fine-grained rock that, when burned at 1500 to 1600°F, can yield a cementitious ash. Thus, oil shale is an energy source which may yield a cement-related byproduct. Oil shale ash has been used since 1922 in cement production (reference 14). Large volumes of oil shale have been used in portland cement manufacture in Russia and Germany. The number of possible applications for cementitious oil shale ash is very large, but the presumed market radius is relatively small because of the sparsely populated nature of the oil shale region.

For example, portland cement shipments in 1986 in the United States totalled 83,995,000 short tons (reference 15). Of this, only about 2.9% originated in Utah, Colorado, and Wyoming. Assuming a market radius of 150 to 300 miles (reference 16), the total demand for cement in the oil shale region must be on the order of 2,500,000 short tons per year. Even if portland cement could be totally displaced by spent shale, a single commercial oil shale plant would produce about 10 times this much shale ash.

One possibility for the use of spent shale ash as a cement provides a good indication of the problems and potential of this type of application, and, as such, is specifically mentioned in the Statement of Work. Spent shale could possibly be used to advantage as a soil stabilizing agent (soil cement) for road subgrade bases and sub-bases. Typically, soil cement is a simple, intimate mixture of pulverized soil and measured amounts of portland cement and water, compacted to a high density. Soil cement is used primarily as a base course for roads, streets, and airport paving. A bituminous wearing course is placed on the surface of the finished base course to complete the paving. Other uses of soil cement include road widening, shoulders, reconstruction of failing granular bases, patching, drainage ditch and canal linings, reservoir linings, facing for berms and dams, and earth-core dams (reference 17).

Chemical stabilization is an alternative to removal of soils which do not have adequate load carrying capacity. Various stabilizing agents (lime, lime/fly ash, fly ash, cement, asphalt, etc.) are recommended, depending upon the characteristics of the soil and the agent (reference 18). It is important to spread the stabilizing agent evenly over the area to be stabilized and to mix it evenly and well with the material. Depending upon the soil classification, the estimated cement content varies from 5 to 13 percent by weight (reference 24). Inasmuch as the shale ash is a byproduct which requires a considerable investment over a long period of time, if it is to be disposed of on site, its price at the site can be set fairly low. Transportation costs then become the dominating factor once the material becomes officially accepted as a stabilizing agent or soil cement.

To derive an input for economic analysis, we gathered estimates and statistics on the likely use of soil stabilizers for road-bed subsurfaces over a region (radius of 500 miles) over which oil shale was calculated to be economically competitive for this application. Volume computations led to an estimated sale of 374 tons per day for a single oil shale facility located at the center of the defined area. The establishment of a possible price range and the estimate of a corresponding market for this application are covered more fully in Subsection 5.2.3.

In summary, note that the foregoing discussion concentrated upon only one possible application for the cementitious properties of oil shale ash. Other possibilities could be reviewed, e.g., soil stabilization for secondary unpaved roads such as those in national forests. Any of several possibilities could either supplement the one application treated herein or replace that application if it failed to materialize as hypothesized. Much testing of specific properties would be needed to establish criteria for the use of spent shale as a stabilizing agent under various conditions and design requirements. The market could be 1.5 to 2 times the size of the primary market we analyzed with the highway reconstruction and use on secondary roads, applications for which we do not have a defined market at this time.

Thus, there are many uncertainties in the factors and estimates used in this analysis. However, as discussed in Section 5, the financial impact of the sale of shale ash as a cementing agent is positive but so small under foreseeable circumstances that it does not seem likely to have a significant impact upon the potential commercialization of the oil shale resource. What this means is that shale oil still must be produced economically and the secondary products can yield a positive impact on the profit.

5.0 ECONOMIC ANALYSES

5.1 Methodology

The analyses presented in this section rely upon the use of a discounted cash flow return on investment (DCFROI) model for evaluating representative oil shale development and operation scenarios for the western oil shale region of the United States. The selection and development of scenarios is covered in Section 4.0. This subsection describes the DCFROI modeling approach and the reasons why the DCFROI criterion is considered most useful for evaluating the oil shale options considered in this report.

For purposes of evaluation of oil shale options, we take the position that the purpose of oil shale development is to create a productive and profitable operation which can attract investors because it promises to investors an adequate rate of return on invested capital. This return must consider the time value of money and the degree of risk of the operation. The Statement of Work for this study does not require the analysis of risk, but does require some consistent means of comparing alternatives. Economic analysis provides such a means. The value of economic analysis as provided by DCFROI modeling is not that it offers absolute validity of results (impossible to guarantee in view of the problematical aspects of energy development), but that it provides a convenient and consistent way for complex issues to be treated.

The basic measure of project merit under this concept is the net present value (NPV) of project net cash flows, including the initial investment outlay. Net present value is computed by discounting all project cash flows (CF) back to a common reference period. NPV is the amount by which capitalized value would change if the project were undertaken (if all discounting is done at a single discount rate). This quantity may be plotted against various discount rates (R). The DCFROI is defined as that value of R which satisfies the equation:

$$\sum_{t=0}^{N} \frac{CF_t}{(1+R)^t} = 0.$$

Though DCFROI is considered crucial in attracting investment capital for oil shale development, no single value is adequate for expressing the economic worth of a project. Other indicators upon which the discussions in this section rely include cumulative cash flow over the life of the project, payoff period, maximum equity exposure, interest coverage ratio, and debt service ratio. Taken together, these indices provide a thumbnail description of the likely worth of an individual project.

Several weaknesses of this type of analysis are apparent. If the projects so modelled are not representative of the likely course of oil shale development, the results of their economic analyses are of little value. Technological change, new governmental policies such as incentive programs or significant regulatory changes, and other factors could make the outputs of the analyses obsolete. Even without such change, omission of significant cost factors or unrealistic design assumptions could invalidate results.

To minimize the disadvantages of the DCFROI scenario approach, we have adapted project designs which have been developed through intensive engineering effort and subjected to extensive review by outside agencies. The designs are suitable to a large portion of the oil shale resource in the western United States. Thus, they are as nearly representative of likely near-term oil shale development as we are able to attain, and they are widely applicable and relatively complete.

5.2 Scenario Development

Section 4 described the unconventional uses for oil shale considered in this report. The description included a general survey of the potential market for each possibility.

The scenario approach based upon evaluation of a small number of representative cases requires that we reduce the general market data contained in Section 4 to specific inputs for our DCFROI model. This subsection describes how that process was accomplished.

5.2.1 Cogeneration

Shale oil is considered to be the major product of oil shale operations for all scenarios used in the study. The major byproduct of such operations would be electricity. This electricity, which would be produced from waste fuels and heat, could be sold to a utility company at the "avoided costs" as contemplated by PURPA, or a utility company could purchase the fuels and heat and sell power. The oil shale facility would include a fluid bed combustor (FBC) which would not only burn the shale, retorted shale, and offgas, but would also scrub the sulfur dioxide from the offgas, thereby eliminating a major environmental concern related to shale oil production.

Since shale oil is the major product for all scenarios, the design of the representative oil shale projects evaluated herein is optimized, insofar as possible, with respect to shale oil production. Two major types of operations suitable to the main western oil shale resource and environment are considered: (1) underground mining with conventional surface retorting, and (2) a combined surface processing/vertical modified in situ (VMIS) operation. Each is suitable for cogeneration.

Existing project designs (reference 1) for each type of operation were adapted for use in this study. The amounts and characteristics of byproduct fuel available for the FBC were calculated and used in sizing the cogeneration facility. Existing cost data were updated.

Tradeoffs considered in formulating the scenarios included scheduling, pricing, and ownership operations. Sensitivity analyses resulted in selection of accelerated schedules (Subsection 5.2.4) and pricing schedules. Two ownership options (project ownership and utility company ownership) were found to be feasible, and were evaluated separately in the DCFROI analyses described in Subsection 5.3.

The values of the main constants and variables needed for the DCFROI analysis of this option are listed and defined in Subsection 5.3. As reported therein, cogeneration is a very attractive option, typically yielding increases of more than five percent in DCFROI.

5.2.2 Use of Spent Shale as a Sulfur Absorbent

We performed a series of analyses to determine the relative cost-effectiveness of oil shale and limestone as a sulfur absorbent. Even ignoring its energy contribution, oil shale consistently out-performs limestone on demonstration-sized fluid bed units by a factor ranging from 1.7:1 to 2.2:1, depending on absorbent/sulfur ratio (reference 19).

Inasmuch as the sale of oil shale is considered to be a byproduct of a commercial-size oil shale facility, the selling price of oil shale can be set somewhat arbitrarily. We assume a price of $10.00/ton, which ensures that mining costs are more than covered and there is economic incentive for the producer, yet which is low enough to give oil shale a competitive advantage. Mining costs for oil shale range from $3.00 to $5.00 per ton, so a sale price of $10.00 would provide a substantial return. Estimated mining costs for limestone, based on prices for delivered material, are about $16.00 per ton, putting limestone at a competitive disadvantage and making it possible to create economic incentives (in addition to the energy and performance incentives mentioned above) to encourage utility companies to consider switching to the use of oil shale for sulfur removal.

The economic competitiveness of oil shale versus limestone then is primarily governed by the relative cost of shipment of the oil shale or its competitor to a potential customer's facility. This is a function of relative distance from source to plant site. These results are illustrated in Figure 4.2-1, which shows that oil shale can generally be transported 6 to 15 times as far as limestone and still be economically competitive.

We used Figure 4.2-1 in conjunction with a survey sample for the western United States which indicated that limestone is typically shipped 75 to 200 miles (e.g., Nucla plant shipment distance is about 85 miles, shipment from Wyoming mining site to Hayden plant is about 200 miles). This established a radius of at least 700 miles from Rifle, CO, defining an area throughout which oil shale should be economically competitive as a sulfur sorbent. Within that area are several 400-mw power plants, and we based our cash-flow analysis on the assumption that a typical oil shale project might expect to capture one such plant as a customer. (Actually, the first commercial oil shale plant might capture several, but subsequent plants would presumably reduce this share because of more favorable locations: lack of a fully developed commercialization scenario led to the choice of one 400-mw plant as a conservative estimate for purposes of analysis.)

For the 400-mw plant, we assumed a conversion efficiency of 35%, 10,000 Btu/lb coal averaging 2% sulfur, and 90% sulfur removal efficiency (needed to meet the Colorado standard). Use of our derived oil shale sulfur removal tables led to an oil shale demand of 603 T/D for a representative plant. A conservative number of 500 T/D was used, which could be more realistic for lower-sulfur coals, a plant operating under less stringent conditions outside Colorado, etc. In any case, it is clear that the total demand for oil shale as a sulfur absorbent within the defined market area is small compared with the production rate of even a modest western oil shale industry, for which a mining rate of 70,000 T/D per project is likely under recent plans.

DCFROI analyses based on these results are described in Subsection 5.3. For a representative oil shale project, the sale of 500 T/D would increase the return on investment by 1 or 2 percent.

5.2.3 Use of Spent Shale for Soil Stabilization

The potential market for spent oil shale as a soil stabilizer was based upon the practice of adding a soil stabilizer to road-bed subsurfaces as an alternative to removing such soils and replacing them with soils possessing the required stability. The procedure used in defining the potential market was as follows:

1. A representative of the Federal Highway Administration (FHWA) reviewed recent FHWA experience and derived a percentage of subsoil which would be unacceptable in a typical mile of roadway. Together, we estimated that such soils would need to be replaced (or stabilized) to an average depth of three feet. We also derived an estimate of the per-mile footage and volume of unstable soil along cuts or in fills.

2. From preliminary cost data for oil shale and its competitors (replacement or use of portland cement as a stabilizer), we derived a potential radius of 500 miles around Rifle, CO, as a market area. Within this defined area (including all or parts of seven states), FHWA tabulated the 1988 federal, state and county road project miles.

3. We estimated that 70% of the scheduled project mileage would actually be constructed in a year. We further estimated that we could capture 50% of this market if we were to sell the oil shale at a cheaper equivalent price than its major potential competitor (portland cement).

4. Current data indicate that portland cement would typically be added to the unacceptable soil at a rate of 3% by volume. Data from the University of Wyoming (reference 24) indicate that oil shale ash would need to be added at the rate of 15% by volume to ensure competitive results.

5. Since oil shale ash is a byproduct of oil shale operations, its price can be set to virtually any arbitrary value. Sale of the ash would reduce disposal/reclamation costs by an amount considered sufficient to defray any added administrative costs incurred in the sale.

From steps 2 through 4 we obtained:

375,000 tons/project/year (planned) x 0.7 completion value x 0.5 capture rate, or about 131,000 tons/year (about 374 tons/stream day).

This would require economic competitiveness, which we assumed could be demonstrated if oil shale ash were sold at 10% less than an equivalent amount of cement. We obtained a current local wholesale price for portland cement of $66.00/ton. Considering that one ton of portland cement would be equivalent to five tons of oil shale ash (step 4), we obtain:

0.9 (price undercut) x $66.00/ton (competitor)/5.0 efficiency factor or $11.88/ton of spent shale ash.

Based on these considerations, we used a sale of 374 T/D and a sale price of $11.88/ton in the cash-flow analyses reported in subsection 5.3. As with all solid products, the foreseeable potential market for this use of oil shale ash is rather small compared with production from even a small commercial project.

Subsection 5.3 describes the results of DCFROI analyses based on these inputs. As illustrated therein, this option yields increases in DCFROI and cumulative cash flow which would probably be significant only if oil shale were already approximately competitive with conventional energy sources.

5.2.4 Benefits of Schedule Acceleration

Most oil shale development plans advanced for consideration by the former United States Synthetic Fuels Corporation (SFC) featured very large surface retorts. The developers presumably anticipated that economies of scale would give their projects a competitive advantage. They were willing to accept the possibility that the entire project would go out of production if the single large retort suffered a major failure. However, a lesser-noticed but perhaps more significant disadvantage of the single, large-scale retort was the impact on DCFROI of a stretched-out period before shale oil production could begin. In earlier work for a confidential client, we found that the substitution of small, modular retorts would allow production to begin earlier, generating positive cash flow and significantly increasing the project's discounted cash flow return on investment.

Two approaches for investigation of this part of the current study were considered. One approach would have required the design of modular and large-scale retorts and the development of accelerated and conventional schedules for each. This possibility was rejected as inconsistent with the other analyses presented herein and beyond the scope of the Statement of Work. This led to selection of the other approach, which comprised (1) the adaptation of the same surface/VMIS design used for evaluation of other options to this purpose, and (2) measurement of the financial impact of a phased operation (demonstration phase followed by commercial phase) with both accelerated and stretched-out schedules. The selected approach made it possible to compare the potential benefits of schedule optimization with those of the several unconventional uses of oil shale evaluated in this study.

The values of the main parameters used in this analysis are presented in Subsection 5.3. As illustrated therein, schedule acceleration can increase project DCFROI by almost 10 percent for a typical case.

5.3 Summary of Cash Flow Analyses of Oil Shale Options

Table 5.3-I illustrates the effect of (1) cogeneration of export power, (2) cogeneration plus sale of oil shale as a sulfur absorbent, and (3) cogeneration plus sale of oil shale ash for both sulfur absorption and soil stabilization. Two representative oil shale projects were used in evaluating these effects: (1) a relatively small surface processing facility (Cases 1A through 1E) and (2) a balanced surface processing/vertical modified in situ (VMIS) facility (cases 2A through 2D).

For each project, two main options were considered: (1) a joint operation in which a utility company constructs, owns, and operates a co-located power facility, and (2) a situation in which the power generation facility is project-owned.

Insofar as possible, the two representative projects are evaluated in a consistent manner. Table 5.3-II lists the major parameters which are held constant in the computer analyses reported herein.

Tables 5.3-I and 5.3-II are largely self-explanatory. Therefore, the following discussion covers only the essential elements of the inputs and outputs of the study.

Table 5.3-I uses four economic criteria for evaluating the oil shale options as follows:

(1) Discounted cash flow return on investment (DCFROI). This is considered to be the most important single criterion. Note that, in order to bring the DCFROI into a reasonable range, it was necessary to use a shale oil price of $45.00 per barrel for the surface-processing-only project and $30.00 per barrel for the larger, balanced VMIS/surface processing facility. A DCFROI of 15% is used for technologies such as this that have not yet been commercialized, but do not require technical breaktroughs.

(2) Payout years, i.e., payout year is that in which the cumulative project cash flow becomes (and henceforth remains) positive.

(3) Maximum equity exposure, i.e., most-negative cash flow value encountered during the project's life cycle.

(4) Cumulative cash flow, i.e., net project value, at zero-percent discount.

TABLE 5.3-I

SUMMARY OF OUTPUTS OF DCFROI RUNS TESTING VARIOUS OIL SHALE OPTIONS

Case No.	Thumbnail Scenario Description* 1	2	3	4	5	DCFROI (%)	Payout Years	Max. Equity Exposure ($x1000)	Cumulative Cash Flow ($x1000)
1A	8550	45.00	EUO	No	S	17.25	13	- 61,983	661,801
1B	8550	45.00	EPO	No	S	17.03	14	- 67,659	782,231
1C	8550	45.00	IPO	No	S	10.38	19	-108,658	488,943
1D	8550	45.00	EUO	500	S	17.97	11	- 61,983	686,483
1E	8550	45.00	EUO	874	S	18.62	7	- 61,983	708,670
2A	22000	30.00	EUO	No	V/S	18.62	6	-144,219	322,600
2B	22000	30.00	EPO	No	V/S	8.81	24	-194,281	149,451
2C	22000	30.00	EUO	500	V/S	20.62	6	-142,110	358,180
2D	22000	30.00	EUO	874	V/S	23.00	6	-138,019	392,271

*Legend for Thumbnail Description

1 = Shale oil output, bbl/day
2 = Assumed selling price for syncrude, $/bbl
3 = Cogeneration: EPO = export power, project-owned plant; EUO=export power, utility-owned plant; IPO = adequate power for internal use only, project-owned plant
4 = By-product sale: No = none; 500 = 500 T/D
5 = Type of process: S=surface process only; V/S = balanced, modified in situ with surface component

TABLE 5.3-II

SUMMARY OF CONSTANTS USED FOR DCFROI RUNS

PARAMETER	VALUE USED (As Applicable)
1. Project life	30 years
2. Inflation rate	0
3. Debt-equity ratio	0.75
4. Sale price for excess power	$0.045/kw-hr
5. Sale price of energy to utility-owned power plant	$0.50/million Btu
6. Purchase price for power	$0.045/kw-hr
7. Oil shale sale price (SO_2 removal)	$10.00/ton
8. Oil shale ash sale price (soil stabilizer)	$11.88/ton

The impact of cogeneration is best illustrated by comparing the results of case 1C with those of cases 1A and 1B. In case C, the project produces only enough power to meet its own internal needs and provide sulfur removal, whereas cases 1A and 1B provide maximum excess power consistent with the types of processes employed. By all criteria, co-production of electricity is economically attractive when producing shale oil. Therefore, the cogeneration option was used as the base case when evaluating other options.

An improvement in DCFROI may be obtained if a utility company constructs the power plant, purchases energy from the oil shale plant at about half the cost of energy from coal, and sells the needed amount of power to the project at cost. The improvement is more pronounced for the balanced facility (case 2A versus case 2B) than for the smaller project (case 1A versus case 1B). The relative impact is scenario-specific, but the utility-owned option, being superior in varying degrees in all cases studied to date, is used as the basis for evaluating the incremental impact of other options.

The sale of shale ash reduces disposal/reclamation costs and yields added income, so its impact is primarily a function of the size of the market within an area in which oil shale can be economically competitive. Our comparative effectiveness and marketing surveys indicate that a representative western oil shale project might expect to sell about 500 T/D for use as a sulfur absorbent and about 374 T/D for use as a soil stabilizer at the prices shown in Table 5.3-II. The economic impact of the sulfur-absorbent possibility is similar for the two projects (case 1D versus case 1B and case 2C versus case 2A). Further incremental benefits of similar magnitude are obtainable by adding the sale of shale ash for soil stabilization (case 1E versus case 1D and case 2D versus case 2C). As with all solid products, the potential market is rather small compared with production from even a small oil shale project.

Table 5.3-III presents an analysis of the same options from a slightly different perspective. Here, it was assumed that a DCFROI of 15 percent would be needed to satisfy the investor's requirement for an adequate financial return on a commercial oil shale project. Based on this assumption, the required selling price for shale oil was computed for each option. Comparison between Tables 5.3-I and 5.3-III shows about the same relative impact of the various options listed. However, it is noteworthy that the required selling price for the most favorable option (Case 2D) is within $9/barrel of the price of crude oil at the time the cash flow analysis was made. This suggests that oil shale is worthy of serious consideration as an alternative energy source - one which would be secure, abundant, and a significant contributor to the desired reduction in our nation's trade deficit.

TABLE 5.3-III

SUMMARY OF OUTPUTS OF DCFROI RUNS FOR FIXED DCFROI OF 15 PERCENT

Case No.	Thumbnail Scenario Description*					Avg. Cash Flow (Prod.) ($x1000)	Payout Years	Max. Equity Exposure ($x1000)	Cumulative Cash Flow ($x1000)
	1	2	3	4	5				
1A	8550	43.00	EUO	No	S	23,680	17	- 61,983	578,299
1B	8550	42.95	EPO	No	S	28,309	17	- 67,659	697,829
1C	8550	49.85	IPO	No	S	28,079	17	- 66,272	690,443
1D	8550	42.44	EUO	500	S	23,738	17	- 61,983	579,954
1E	8550	41.80	EUO	874	S	23,572	17	- 61,983	575,768
2A	22000	29.41	EUO	No	V/S	9,745	6	-145,740	241,214
2B	22000	31.00	EPO	No	V/S	10,363	6	-191,704	283,564
2C	22000	29.10	EUO	500	V/S	9,137	6	-144,430	234,053
2D	22000	28.74	EUO	874	V/S	8,404	6	-141,266	218,600

*Legend for Thumbnail Description
1 = Shale oil output, bbl/day
2 = Required selling price for 15% DCFROI, $/bbl
3 = Cogeneration: EPO = export power, project-owned plant; EUO = export power, utility-owned plant; IPO = adequate power for internal use only, project-owned plant
4 = By-product sale: No=none; 500 = 500 tons/day
5 = Type of process: S=surface process only; V/S = balanced, modified in situ with surface component

The concept of backfilling spent oil shale waste into the mine was discussed in Section 3. It was pointed out therein that backfilling using current technology is more expensive than surface disposal, but that total resource recovery is increased through the use of backfilling. This raises the question of whether the added cost of backfilling is offset by the added resource recovery.

A single case was used to obtain an indication of the economic justification for backfilling. Case 1A from Tables 5.3-I and 5.3-III was selected as representative. The results of the comparison are summarized in Table 5.3-IV. Using discounted cash flow return on investment as the dominant criterion, we note that backfilling is not an attractive option to the investor. However, total project profit over the life of the project is significantly improved under the backfilling option, and other criteria are more or less neutral. Other potential factors (e.g., regulatory changes making surface disposal more difficult, advances in technology, governmental incentives favoring increased resource recovery) could change the conclusions based herein on DCFROI, but under current conditions backfilling is not economically attractive for typical oil shale projects.

TABLE 5.3-IV

SUMMARY OF OUTPUTS OF DCFROI RUNS
TESTING EFFECT OF BACKFILLING

Case No. **	Thumbnail Scenario Description* 1	2	3	4	5	DCFROI (%)	Payout Years	Max. Equity Exposure ($x1000)	Cumulative Cash Flow ($x1000)
1A	8550	45.00	EUO	No	S	17.25	13	-61,983	661,801
1A (BF)	8550	45.00	EPO	No	S	14.76	17	-61,983	827,239
1A	8550	43.00	EUO	No	S	15.00	17	-61,983	578,299
1A (BF)	8550	45.25	EUO	No	S	15.00	17	-61,983	839,513

Notes:

* See Table 5.3-II for explanation (except that BF option has 35-year project life)
** BF = with backfilling option

The final area considered was that of schedule acceleration. The results are shown in Table 5.3-V. A surface processing/VMIS combined operation similar to case 2A in Table 5.3-I was adapted for this purpose. The following options were considered: (1) an accelerated schedule (case 3A) in which the project moves through a demonstration phase to full production of oil shale and excess power as quickly as possible, (2) a delayed schedule (case 3B) in which a one-year operating period was allowed between start-ups of processing modules, and (3) another delayed schedule (case 3C) in which the cogeneration facility moves ahead of the delayed processing facility. The constants listed in Table 5.3-II were used in each run as applicable.

For most of the decision criteria shown in Table 5.3-V, the accelerated schedule (case 3A) has a great advantage over the other cases. The exception is maximum equity exposure, where accelerated capital investment carries with it a large negative cash flow at one point in the project's life cycle. Otherwise, the advantages of schedule acceleration are readily apparent for this case. The differences are significant enough to indicate that the impact of project schedule optimization as an integral part of the design and planning process may overshadow some of the other options considered herein.

TABLE 5.3-V

SUMMARY OF OUTPUTS OF DCFROI RUNS TESTING VARIOUS OIL SHALE OPTIONS

Case No.	Thumbnail Scenario Description* 1	2	3	4	5	DCFROI (%)	Payout Years	Max. Equity Exposure ($x1000)	Cumulative Cash Flow ($x1000)
3A	22000	35.00	EUO	No	V/S	22.59	14	-154,089	982,061
3B	22000	35.00	EUO	No	V/S	13.44	15	-129,428	485,575
3C	22000	35.00	EUO	No	V/S	13.77	15	-124,641	492,290

*Legend for Thumbnail Description
1 = Shale oil output, bbl/day
2 = Assumed selling price for syncrude, $/bbl
3 = Cogeneration: EPO = export power, project-owned plant; EUO = export power, utility-owned plant; IPO = adequate power for internal use only, project-owned plant
4 = By-product sale: No = none
5 = Type of process: V/S = balanced, modified in situ with surface component

6.0 FINDINGS AND RECOMMENDATIONS

The following findings and recommendations are based upon the analyses outlined in this report.

1. The selection of type of conventional mining is very site dependent. Open pit mining at overburden ratios of more than 1:1 tends to be more expensive than underground mining. Open pit mining is applicable to only part of the oil shale resource.

2. Mining costs for VMIS with a surface retort process are higher than underground (R&P) or open pit mining on a per ton mined basis; however, they are significantly less on a per-barrel-of-oil-produced basis. Thus, if site conditions are favorable, a combined system of in situ retorting with surface processing appears to be the most attractive option from the standpoint of mining.

3. In general, development schedules for oil shale projects are mining limited; thus, a system which allows oil production or the sale of byproducts while mine development is proceeding is more cost effective.

4. The cost of conventional mining is very dependent upon the mining rate. The capital cost per daily ton mined is about $12,000 for the 5,000 T/D mine versus about $5,000 for a commercial-scale mine (e.g., 70,000 T/D). The out-of-pocket operating cost per ton mined is about $5.00 for the small mine versus $3.00 to $4.00 for a commercial-scale mine. Based upon these findings, it is recommended that a project developer explore unconventional uses of the mined material and any other avenues to increase the mine capacity so as to realize the potential economies of scale.

5. The option of re-injecting spent shale into an oil shale mine using current technology is not justified by project economics. However, it is recommended that this option be reviewed periodically as national priorities regarding resource recovery emerge, significant regulatory changes are implemented, or significant technological changes occur.

6. Cogeneration, use of spent shale as a sulfur absorbent, and project schedule optimization can have a significant impact upon the eventual commercialization of the oil shale resource. Cogeneration using fluid bed technology is well understood and accepted, whereas the use of oil shale as a sulfur absorbent needs further study, testing, generalization and promotion.

7. Investors can achieve reasonable rates of return on oil shale projects with syncrude sale prices of less than $30/barrel.

Given the world's and our nation's declining oil reserves, current increases in the price of oil, and continuing national balance-of-trade problems, it appears that concentrated efforts to pursue the promising options discussed herein are in the national interest, and could result in the economic competitiveness of shale oil in the near future.

7.0 DISCLAIMER

Mention of specific brand names or models of equipment is for information only and does not imply endorsement.

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