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Chattanooga Shale: An Assessment of the Resource and Technology for the Recovery of Hydrocarbons and Minerals

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DEPARTMENT OF ENERGY

Report on the State of Affairs in the
New York State of Education
by the Department of Education
under the direction of the Board of Regents
New York, 1892

The Department of Education has the honor to acknowledge the receipt of your report on the State of Affairs in the New York State of Education, and to express its appreciation for the valuable information it contains. The report is a most interesting and valuable contribution to the knowledge of the State of Education in New York, and it is hoped that it will be of great service to the Board of Regents and the Department of Education.

Contract No. W-7405-eng-26

Engineering Technology Division

CHATTANOOGA SHALE: AN ASSESSMENT OF THE RESOURCE AND TECHNOLOGY
FOR THE RECOVERY OF HYDROCARBONS AND MINERALS

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Date Published: April 1982

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UNION CARBIDE CORPORATION
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ABSTRACT

Chattanooga shale, a large and mineral-rich member of the Devonian oil shales of the Eastern United States, is a resource of about 100 billion bbl of oil, 10 million tons of uranium, and significant quantities of other metals including aluminum, molybdenum, cobalt, columbium, and vanadium. Unlike coal and western oil shale, however, Chattanooga shale is not yet ready for commercial exploitation. The hydrocarbon content, while comparable to that of western shales, is more difficult to extract, and the metals, while generally more varied, are less concentrated than those of resources that are being exploited today. Although this study indicates that a large scale (100,000 tons/day) combined operation for oil and metals recovery appears to be economically attractive, commercial operations are presently impeded by the risks associated with the need for an extremely large capital investment and substantial unknowns with respect to environmental effects and the methods for mining, processing, and waste disposal. Some of the principal technical problems that require resolution are those of roof stability and water intrusion associated with the underground mining of Chattanooga shale, the need for environmentally acceptable methods for disposal of tremendous quantities of spent shale, and the need for processes that can efficiently recover most of the hydrocarbon and mineral values with minimal loss of expensive processing reagents.

1. SUMMARY AND CONCLUSIONS

The purpose of the work presented in this report has been to make a preliminary evaluation of the science, technology, and economics associated with the large-scale recovery of hydrocarbons and minerals from Chattanooga shale. Although more dilute than resources that are being exploited today, Chattanooga shale is a uniquely large and versatile resource of hydrocarbon fuel, uranium, and strategic minerals. This Summary and Conclusions will summarize why ORNL has an interest in Chattanooga shale, the nature of the resource and its regional setting, considerations related to shale mining and the management of residues, processes for recovery of oil and minerals, estimated environmental and sociological impacts, and needs for further research and development. Finally, conclusions of the study and recommendations for further work and actions will be summarized.

1.1 Background

The Oak Ridge National Laboratory and the Union Carbide Nuclear Division in Oak Ridge, Tennessee have had a long-term interest in Chattanooga shale - initially because of its enormous content of uranium (a resource of about 10 million tons of U_3O_8 with an average uranium concentration of about 60 ppm) but more recently because of its content of hydrocarbons (a resource of about 100 billion bbl of oil) and minerals (including especially high concentrations and potentially recoverable quantities of aluminum, molybdenum, cobalt, copper, and nickel). From the 1940s through the 1960s Oak Ridge had a lead role in identifying U.S. uranium resources; processes were developed that are now widely used for commercial recovery of uranium from sandstones and phosphate rock, and exploratory development was carried out on uranium recovery from leaner resources such as the Dakota lignites and the Chattanooga shale. The Union Carbide Nuclear Division is a lead participant in the National Uranium Resource Evaluation Program. Beginning in 1973, ORNL has performed research and development work related to fossil energy and for the past five years has devoted 5 to 10% of its resources (representing an annual budget of \$20 to \$40 million) to the physical science, engineering, and health and environmental effects associated with the recovery of energy and synthetic fuels from coal. Concurrently, but at a smaller scale, ORNL has been performing assessment studies and research related to the recovery of strategic metals, particularly those needed for energy applications, from domestic resources.

In view of these historical interests and capabilities, the worsening problem of dependence on foreign countries for oil and strategic minerals, and a continued interest in long-term uranium supply, ORNL undertook this present study in July 1980. The study has been conducted with a very limited budget available from ORNL's discretionary funds but this has permitted an evaluation of the literature, the collection of views from experienced and knowledgeable staff members, a limited number of scouting experiments, and the development of reference design information that has formed the basis for several conclusions and recommendations for further study.

1.2 The Resource and Regional Setting

The Chattanooga shale, a black Devonian shale related to other Devonian oil shales found in the Eastern United States but generally higher in valuable minerals content, underlies a substantial portion of Middle Tennessee, Southern Kentucky, and Northern Alabama. Fig. 1.1 shows the general regional setting and, in particular, areas with thick seams near outcrops which would be most promising for initial mining.

A typical stratigraphic section of the geologic members that include the shale near outcrops in Middle Tennessee is described in Table 1.1. The shale is generally overlain by the thick Fort Payne chert formation which should provide a structurally competent roof for underground mining. The Gassaway member of the shale -- the member that probably would be chosen for initial exploitation -- generally would yield about 10-12 gal of oil/ton with simple retorting (and perhaps twice this with a hydroretorting process to be described later) and has a uranium concentration averaging about 60 ppm. Typical concentrations of other metallic elements in the Chattanooga shale are shown in Table 1.2.

Important water resources in the region occur both as surface and groundwater. Groundwater is an important source of potable water for municipal and private water supplies throughout the Chattanooga Shale Region. Groundwater occurs in alluvial aquifers adjacent to the major streams and rivers in the area, in soil or weathered rock residuum, and in solution cavities in the carbonate bedrock of the region. Alluvial aquifers are not extensively utilized as a source of water because of the more general occurrence of soil and bedrock aquifers.

In terms of present water use and water availability, both surficial and underground, the Chattanooga Shale Region is capable of supporting the growth of water consumptive industries. Water consumption uses only a fraction of the surface and groundwater available on a year round basis. More significantly, the water use for the region consumes only a small percentage of the critical low flow. Water consumption during the critical-low-flow month could increase approximately 10 times before it would cause a potential low-flow water-shortage problem.

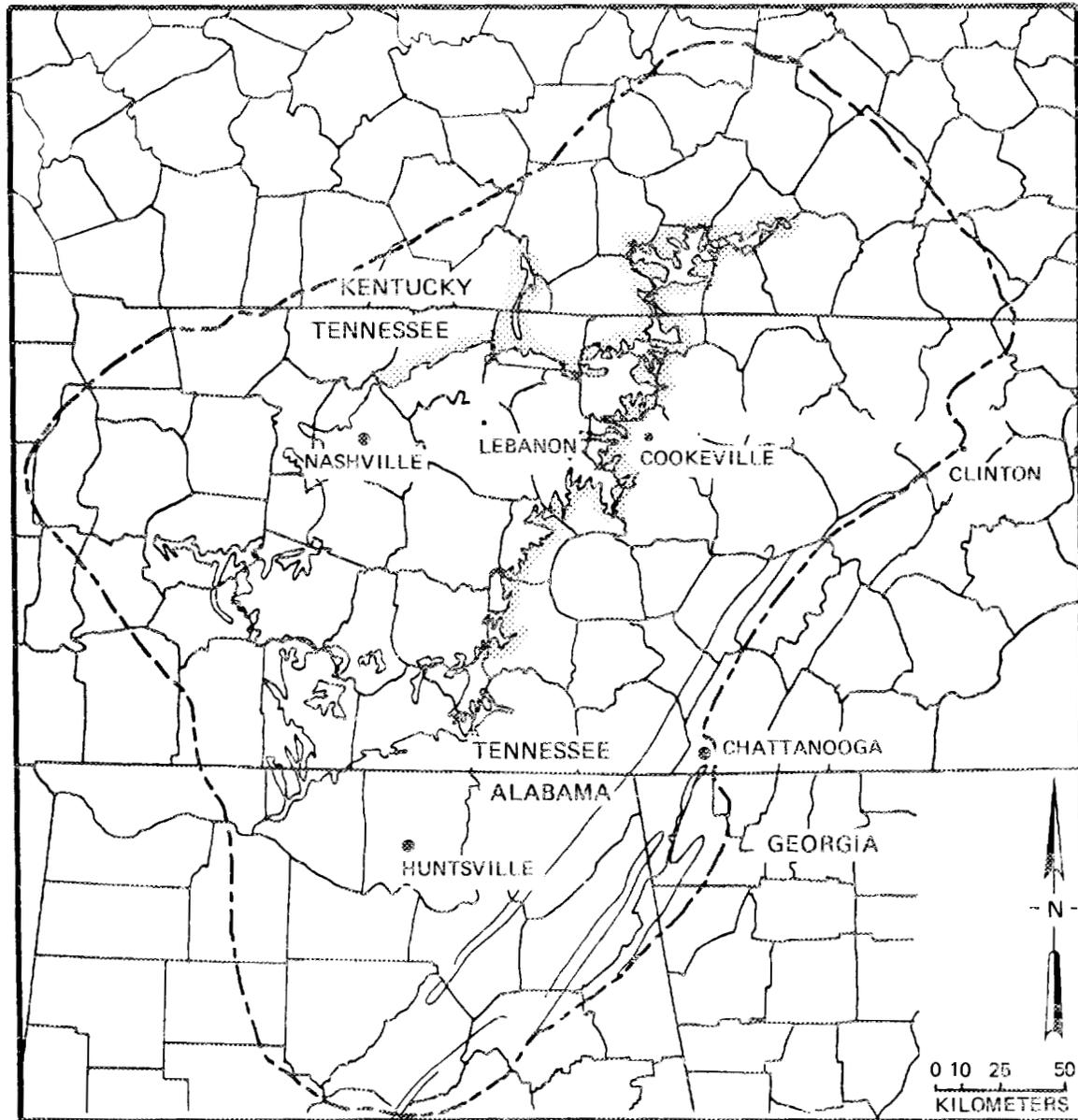


Fig. 1.1. Approximate geographic boundaries of the Chattanooga shale. The shaded area, extending 8 km from the line of outcrops, is the most accessible for mining.

Table 1.1. General stratigraphic column showing the thickness of members and typical contents of oil and uranium of the Chattanooga shale in DeKalb County, Tennessee

Formation	Member	Thickness (m)	Fischer assay (gal/ton)	Uranium (ppm)
Fort Payne chert	Undivided	60+		
Maury formation	Undivided	0.7 ±		
Chattanooga shale	Upper Gassaway	2.1	7.5-10.25	65-75
	Middle Gassaway	0.7	4.0-8.0	37-43
	Lower Gassaway	2.3	8.0-12.5	48-61
	Upper Dowlletown	2.8	2.5-3.5	9-12
	Lower Dowlletown	1.9	8.0-10.5	25-35
Leipers limestone	Undivided	15.2		

Table 1.2. Typical distribution of metallic elements in the Chattanooga shale

Element	Average concentration by weight	Stratigraphic ^a affinity
Aluminum	5.7-6.5%	D/U
Iron	5.8-6.4%	G
Cobalt	100 ppm ^b	G
Chromium	100 ppm	I
Copper	100-200 ppm ^b	U
Manganese	100-500 ppm	U
Molybdenum	200-300 ppm ^b	G
Nickel	30-300 ppm ^b	G
Uranium	40-100 ppm ^b	G
Vanadium	200 ppm	I
Zinc	200 ppm	G/I

^aU = Uniformly distributed
D = Dowelltown member
G = Gassaway member
I = Irregularly distributed.

^b Average concentration in shale exceeds average crustal abundance.

Land use in the Chattanooga Shale Region is varied and closely associated with the physiography of the land. Most of the land is either heavily forested or cleared for cropland and pasture. Urban land comprises the three major cities - Nashville, Chattanooga and Huntsville and their surroundings. Small communities are also dispersed throughout the region. Land used for recreation is significant to the economy of the region but is not large in area.

The climate of the Chattanooga Shale Region is relatively mild and pleasant, interrupted by long summer hot spells and variable winter outbreaks of freezing cold. Average annual temperature is 14.8°C and average annual precipitation is 131.5 cm. Average annual wind speeds are around 3-4 m/sec (7-9 mph). Strong winds associated with tornadoes, hurricanes or blizzards are infrequent compared to most other areas of the country. Existing ambient air quality in the Chattanooga Shale Region is generally moderate for pollutants which have been monitored.

The vegetation of the region reflects the influence of 200 years of settlement. The original vegetation has been cleared or modified such that it no longer reflects physiographic control. Predominant vegetation continues to be broad-leafed, deciduous forest with mixtures of coniferous trees.

The fauna of the region has been enriched in those species which thrive in a mosaic of forests, fields, and extensive water reservoirs. The aquatic biota of the region is highly diverse due to the great diversity of habitats. Seven terrestrial animal species, three terrestrial plant species and nineteen aquatic species appearing on the U.S. Fish and Wildlife Service Endangered Species lists occur within the region.

The socioeconomic environment is clearly divided between the urban areas (e.g., Nashville and Chattanooga) and the rural areas (e.g., counties where mining may occur). Urban areas are experiencing growth by immigration while rural areas contain a population age structure suggesting emigration of a substantial portion of their young people. The urban portions of the region have enjoyed considerable economic growth and have per capita incomes above the national average.

Manufacturing has surpassed agriculture in importance in rural areas but rural per capita income remains below the national average and 40% of

the counties have been declared to be surplus labor areas. The rural areas have a relatively high frequency of substandard housing. All out-crop counties have medical care available, although hospitalization may require travel outside the county. Public education from kindergarten through twelfth grade is available in all counties and specialized schools, vocational-technical schools, and institutions for higher education are available in the region, if not in the home county.

1.3 Mining and Waste Disposal

Large scale extraction of the Chattanooga shale will require underground mining since only a relatively small fraction of the resource is located at or near outcrops with favorably low ratios of overburden to the shale. Mines would extend up to about 5 miles (8 km), generally downward, into the formation from adits at the outcrops. Mining of the shale is assessed to be moderately difficult and expensive but practical if care is used in site selection and the selection and development of mining methods. The most significant mining problems appear to be associated with roof stability and the requirement for continuously removing and disposing of water that seeps into the mine from overlying aquifers. The nominally 2 ft (0.7 m) thick Maury shale that immediately overlies the Gassaway member of the Chattanooga shale would not provide a structurally competent mine roof and might have insufficient strength as a component of pillars. The thick, overlying Fort Payne formation is a hard, siliceous limestone that is generally structurally competent but in some areas contains a moderately porous aquifer that would be a source of significant quantities of water. Mining methods that have been considered include leaving perhaps the upper 10% of the 10 to 20 ft (3 to 6 m) thick Gassaway member of the Chattanooga shale to provide a competent and water-tight roof and longwall or other continuous forms of mining that would exploit the relative softness of the rock and minimize the consequences of roof falls.

The Chattanooga shale will increase in volume during mining and processing. It is estimated that expansion by about 85% in volume will occur during mining, crushing, hydroretorting, roasting and metals recovery. Preliminary calculations suggest that only about 55% of the spent shale

could be backfilled into the original mine if the shale residue is not compacted. Laboratory tests have indicated that the spent shale can be compressed to its original volume at a pressure of 5000 psi. While compression may be feasible, there is no commercial system available and this possibility would have to be explored in a research program.

The magnitude of the solids management and spent shale disposal problem is huge over the life of a design basis processing operation with a capacity of 100,000 tons/d (90,000 Mg/d). Such large scale handling of rock is typical at present only within the sand and gravel industry and the strip mining of coal. For such an operation and assuming a 20-year lifespan, about 500,000 acre-ft (600 million cubic meters) of spent shale would be generated and require disposal. Landfills would be required in flat lands and valley fills could be used in regions of relatively high relief. Revegetation would be required for both types of surface disposal and procedures to control the quality of runoff water would be a necessary ingredient of basins and valley fills.

1.4 Recovery Processes

A schematic diagram of the reference plant design that has been developed for a preliminary technical and economic evaluation of the recovery of hydrocarbons and minerals from Chattanooga shale is shown in Fig. 1.2. Estimated products that would be produced in the plant for several possible modes of operation and a shale feed rate of 100,000 tons/d are shown in Table 1.3.

The reference design of the hydrocarbon recovery process is based upon a hydroretorting procedure that is being developed for eastern Devonian shales at the Institute of Gas Technology supplemented with data from scouting tests with specific Chattanooga shales that were performed at ORNL. In this process crushed shale is contacted with a large recirculating stream of hydrogen at a pressure of 500 psia (34 atm) and temperature of 1220°F (660°C). The overhead gas stream is cleaned and treated to recover oil, sulfur, and ammonia. Hydrocarbon product gases are reformed with steam to replenish the supply of hydrogen. After onsite hydrotreating of the raw shale oil, it is estimated that this plant would produce

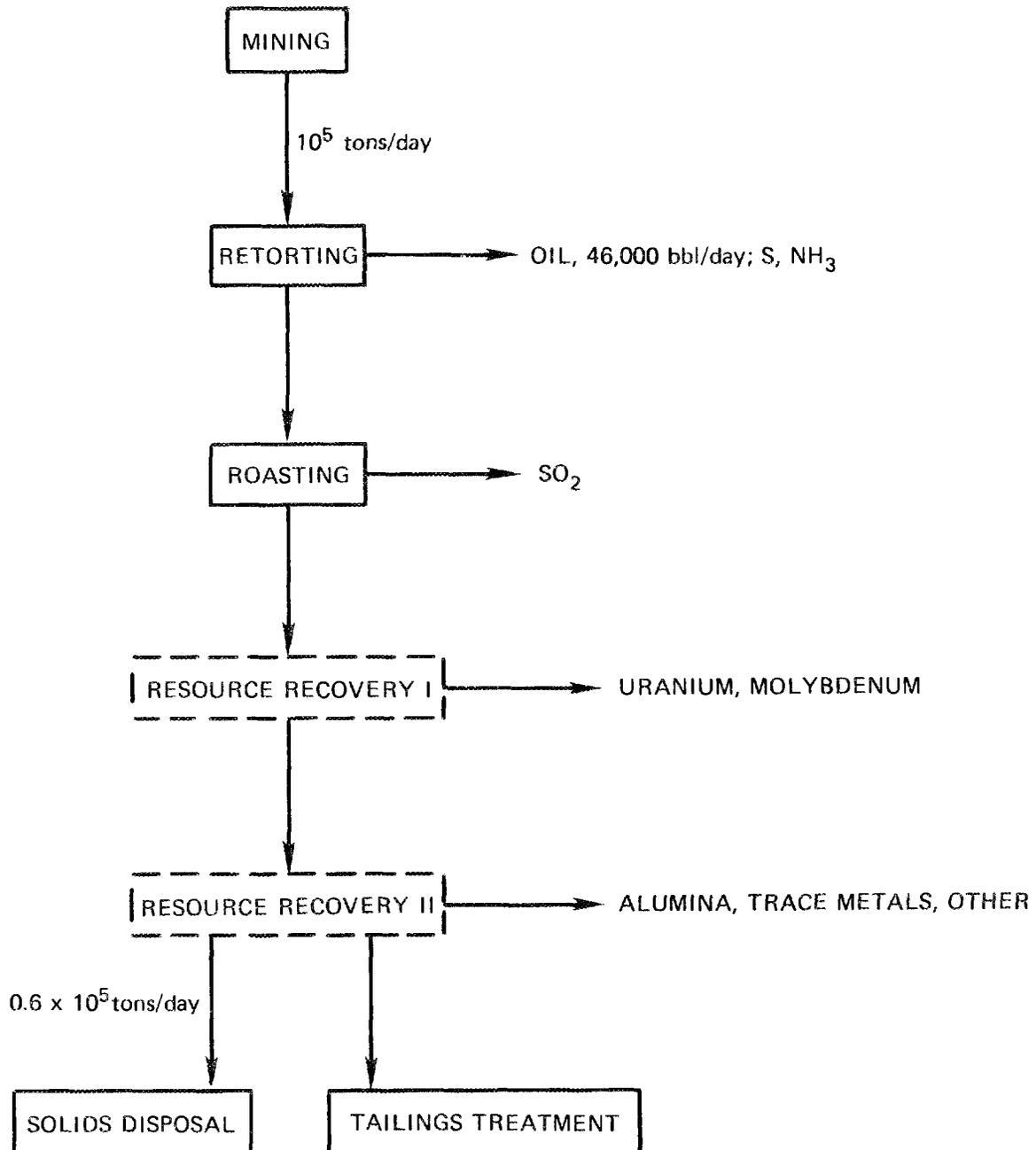


Fig. 1.2. Schematic diagram of reference plant for recovery of oil and minerals from Chattanooga shale.

Table 1.3. Estimated products from various operation modes of reference plants for processing of Chattanooga shale at a rate of 100,000 tons/day

	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Oil, bbl/d	46,000	46,000	46,000	46,000
Sulfur, t/d	2,500	0	0	0
Ammonia, t/d	350	0	0	0
U ₃ O ₈ , t/d	0	6	6	6
MoO ₃ , t/d	0	30	30	36
Al ₂ O ₃ , t/d	0	0	2,700	8,100
Mixed trace metals, t/d (Co, Cu, Cr, Mn, Ni, Vn, Zn)	0	0	0	100

about 46,000 bbl/d of relatively high quality oil suitable for shipment offsite for further refining into gasoline, diesel fuel, jet fuel, and heating oil.

The reference process for minerals recovery has been developed with literature data supplemented with several specific scouting experiments at ORNL. In this process the spent shale from the hydroretorting process is first roasted with air to recover the remainder of the hydrocarbon energy value and sulfur and reoxidize some of the minerals. The roasted shale is leached with sulfuric acid by a procedure that should remove 60-90% of the metals that are to be recovered. This aqueous stream is treated with various solvent extraction and precipitation processes to recovery uranium, molybdenum, alumina, and a concentrate containing mixed oxides of the remaining trace metals. It is then necessary to clean the aqueous wastes and stabilize the solid wastes for disposal.

Several technical findings became apparent in the evaluation:

- Gasification or combustion of the spent shale from the hydroretorting process appears desirable. This makes better use of the energy content of the spent shale, and allows for coproduction of oil and synthetic natural gas.
- For minerals recovery, only moderate extensions of current technology are needed for recovery of uranium and molybdenum; alumina recovery appears feasible but requires research and development; and recovery of Co, Ni, Cu, Cr, and Zn appears possible but current separation concepts are only speculative.
- Much research and development work would be required to develop environmental control technology for the gaseous, liquid, and solid waste streams.

1.5 Economics

An economic assessment was made of the reference plant for recovery of oil and minerals from 100,000 tons/d of Chattanooga shale assuming a plant life of 20 years; and rates of general inflation, federal income tax, and state income tax of 6%, 46%, and 6%, respectively. The rate of return on the investment was calculated based upon the estimated prices

and escalation rates of the oil and other products. Estimates of the capital and operating costs that were derived from the reference plant design and used in the economic analysis are shown in Tables 1.4 and 1.5. Results of the economic analysis are presented in Table 1.6.

These results indicate a favorable return on investment of the postulated recovery modes. Improved economics apparently results if uranium, molybdenum, and some of the aluminum are recovered as opposed to the recovery of oil alone. Recovery of additional aluminum and other trace minerals (full recovery) does not appear as attractive with the reference process.

1.6 Environmental Impacts

A preliminary and qualitative assessment of environmental and sociological impacts that would be associated with the large scale, commercial mining and processing of Chattanooga shale for oil and minerals recovery has been made and is summarized in Table 1.7. The major potential impacts that can be identified now and which would require more study are those associated with the requirement for disposal of the extremely large quantities of spent shale and their potential for disrupting the water quality and land uses of the region. Impact of mining on groundwater resources may also be high. Only moderate to low impacts are currently estimated for other regional characteristics such as water consumption, atmospheric quality and socioeconomy of the region.

1.7 Needs for Research and Development

The most pressing needs that have been identified for research and development that would permit a more realistic evaluation of the technical feasibility, economic viability, and environmental and sociological acceptability of the recovery of hydrocarbons and minerals from Chattanooga shale are for:

- an improved scientific basis, engineering data, and an energy-efficient integrated process for the recovery of oil and gas,
- assessment and development of unit operations and an overall approach for minerals recovery,

Table 1.4. Capital investment cost summary
(10⁶ 1980 \$)

	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Mining	170	170	170	170
Solid waste disposal	70	70	70	70
Oil recovery plant	1,700	1,700	1,700	1,700
Roasting	25	25	25	25
U + Mo recovery	0	400	400	400
First aluminum step	0	0	75	75
Final recovery	0	0	0	710
Tailings treatment	0	85	85	170
Total	1,960	2,450	2,520	3,320

Table 1.5. Operating and maintenance cost summary
(10⁶ 1980 \$/year)

	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Mining	125	125	125	125
Solid waste disposal	35	35	35	35
Oil recovery plant	130	130	130	130
Roasting	15	15	15	15
U + Mo recovery	0	75	75	75
First aluminum step	0	0	60	60
Final recovery	0	0	0	380
Tailings treatment	0	35	35	70
Total	305	415	475	890

Table 1.6. Economic results

	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Return on investment, %	23	24	27	23
Revenue source, %				
Oil	93	70	59	43
S + NH ₃	7			
Uranium		16	14	10
Molybdenum		14	12	10
Aluminum			15	31
Trace metals				6

Assumed prices	1980 prices (\$)	Escalation (%/year)
Oil, \$/bbl	35	9
U ₃ O ₈ , \$/lb	30	9
MoO ₃ , \$/lb	7.50	6
S, \$/t	45	6
NH ₃ , \$/t	155	6
Al ₂ O ₃ , \$/t	200	6
Mixed trace metals	1/2 market price	6

Table 1.7. Preliminary assessment of impacts from a
100,000 ton/day Chattanooga shale plant

Aquatic

Groundwater - high potential contamination and disruption.
Surface water - medium impacts - silt, solubles.
Water use - low potential.
Wild and scenic rivers - low potential.

Terrestrial

Land use - high potential impact, aboveground waste.
Soils - medium impacts.
Subsidence - medium impacts.
Scenic areas - low potential.

Atmospheric

Air quality - medium impacts, dust, SO₂.
Noise - low potential.

Biology

Revegetation and recovery - High-to-medium potential impacts.
Aquatic - Medium-to-low impacts.

Socioeconomics

Low, perhaps favorable, impacts.

Conclusions

Limited, local constraints.
No "show stoppers."
Research needed on waste disposal, stabilization, and revegetation.

- research, development, and assessments in mining and waste disposal, and
- research into health effects of shale oil fractions (e.g., aromatics and trace metals), gaseous effluents, and aqueous effluents.

Research and development needs that now appear to be less pressing but would be required as part of an integrated program include:

- Resource and regional assessments including studies of geology, hydrology, geochemistry, geography, and socioeconomic and institutional factors.
- Basic chemical and physical research to evaluate properties of the Chattanooga shale, provide process kinetic and thermodynamic data, and evaluate the basis for improved recovery processes.
- Engineering development of mining, conveying, crushing, backfilling, and process equipment, materials development, and the development of improved instruments and controls.
- Analytical studies to guide site and process selection and evaluate effects of environmental, socioeconomic, and institutional issues.

1.8 Conclusions and Recommendations

The following conclusions have been made as a result of this study:

- Chattanooga shales are a very large and potentially important energy resource (100 billion barrels oil, 10 million tons uranium)
- Recovery of oil and minerals from Chattanooga shale appears feasible and economically attractive in the long term. The risk would be reduced and profitability improved through R and D.
- Oil and SNG produced from Chattanooga shales are close to major markets and/or pipelines.
- The development of Chattanooga and other eastern shales can provide a hedge against environmental or resource constraints that might impede the rate of western shale-oil production. Although western shale and coal appear to be the most promising sources of synfuels in the short- and mid-term, eastern shales are likely to become important in the long-term.

- Strategic minerals recovery could be an increasingly important incentive for commercial development of Chattanooga shale.

It is further concluded that Chattanooga shales meet reasonable guidelines for government-sponsored research and development:

- It is a major national resource.
- Chattanooga and other eastern shales offer a credible alternative (or supplement) to coal and western shale.
- R and D in Chattanooga shale involves relatively high-risk and long-term programs of the type that would not normally be undertaken by private industry.

It is recommended that ORNL seek support from the U.S. DOE for research and development of methods for recovery of hydrocarbons and minerals from Chattanooga and other eastern shales.

- ORNL is well qualified to manage and carry out a complete program (engineering, science, environment).
- No other federal laboratory or research center has a fully integrated program in eastern shale development.
- ORNL has unique capabilities in many of the relevant R and D program areas.
- ORNL is located in same geographical area as the resource.
- Such an effort would fit well with ORNL interests in strategic minerals.

The roles that might be appropriate for ORNL include:

- technical evaluation and program management,
- process R and D for oil/gas recovery,
- resource recovery research, development and demonstration,
- research to enlarge the technology base, and
- environmental research and evaluation.

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2. INTRODUCTION

The U.S. is totally dependent on foreign resources and imports for supplies of chromium, cobalt, tantalum, and tin. Large amounts of alumina, antimony, manganese, nickel, niobium, and the platinum metals are also imported for economic reasons, although there are long-term U.S. resources of these critical elements (Silverman 1979 and Goeller 1980). One potential source for the domestic production of some of these metals is the Chattanooga shale, a major component of the eastern Devonian shales.

Considerable effort was expended during the period from 1944 to 1960 in investigating the Chattanooga shales, mainly for their uranium content (Mutschler 1976). This work was discontinued in view of the extensive finds of uranium in the western U.S. The continuing depletion of higher grade U.S. reserves, along with the possible future growth in demand of the nuclear industry, led DOE to fund a more recent contract with Mountain States Mineral Enterprises, Inc., to determine the feasibility of future large-scale production of uranium from the Chattanooga shale. Also, recent investigations of the Institute of Gas Technology (IGT) have suggested that the Devonian shales of the eastern U.S., including the Chattanooga shale, can be a major source of oil and gas (Weil 1979).

Mountain States concluded that a plan involving the production of synthetic oil from shale by IGT's hydroretorting process, along with the recovery of uranium and possibly other metal coproducts, was not only feasible but also economically viable (Mountain States 1978). Handling the waste volumes and tailings was determined to be a difficult problem, although it was estimated that about 70% of the waste could be reinserted into the mined-out areas. Laboratory tests at Oak Ridge National Laboratory (ORNL) confirmed that uranium and many of the trace strategic minerals could be leached from the retorted shale (Silverman 1981).

As a result of this renewed interest in Chattanooga shale, ORNL began internally funded studies starting in July 1980. The general objectives of these studies were the following:

- To provide an overall assessment of the Chattanooga shale resource and the technology for production of oil, uranium and strategic metals.

- To define specific needs for research and development if the resource were to be developed.
- To develop capabilities within the laboratory staff to contribute to DOE's eastern shale activities.

The internally funded studies cover an overall assessment of Chattanooga shale (reported here), an environmental assessment, and process experiments on oil recovery and metal extraction. The environmental assessment will be reported separately but information from that report appears in Chapters 3 and 7 of this report. The process experiments are still underway but some preliminary results are presented in Chapter 5.

This report consists of a resource and regional assessment (Chapter 3), a discussion of mining and solid waste disposal (Chapter 4), a discussion of recovery processes (Chapter 5), an economic assessment (Chapter 6), an environmental assessment (Chapter 7), and a discussion of research and development needs (Chapter 8).

3. ASSESSMENT OF RESOURCE AND REGION

3.1 Geologic Setting

The discussion of geologic setting includes physiography of the Chattanooga Shale Study Region, area and structural geology of the region, and the shale geochemistry and mineralogy.

3.1.1 Physiography

The Chattanooga Shale Region lies in two major physiographic provinces - the Interior Low Plateaus Province and the Appalachian Plateaus Province. Within the study area, the Interior Low Plateaus Province includes the Western Highland Rim, the Central Basin, and the Eastern Highland Rim (see Fig. 3.1). The Appalachian Plateaus Province is referred to as the Cumberland Plateau in northern Alabama and southern Tennessee and as the Cumberland Mountains in northern Tennessee.

The physiography of the region is directly related to the bedrock geology.

3.1.2 Geology

Bedrock formations which occur in the region discussed in this report range in age from Ordovician (the oldest rocks in the area) to Pennsylvanian (the youngest rocks in the area). A stratigraphic section is presented in Table 3.1 showing the position of the Chattanooga shale in relation to the other rocks. The Chattanooga shale outcrops at the boundary between Ordovician and Mississippian age rocks - along the boundary between the Highland Rim and the Central Basin. The Chattanooga shale once overlaid the Central Basin; however, weathering and erosion have removed the shale and all overlying strata from that area. The Chattanooga shale lies beneath the Mississippian and Pennsylvanian strata of the Cumberland Plateau and the Highland Rim areas.

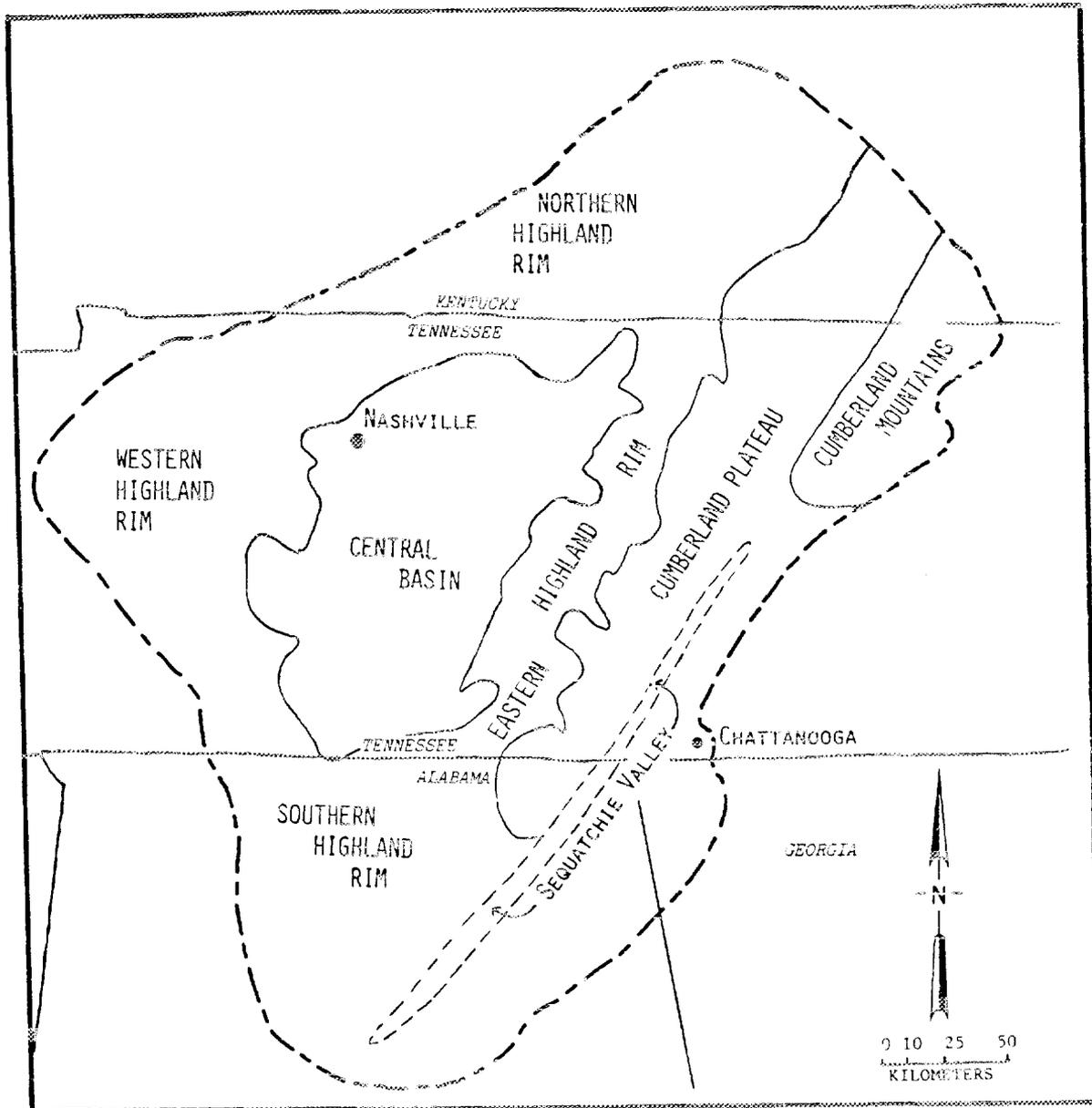


Fig. 3.1. Physiographic regions within the Chattanooga shale study area.

Table 3.1. Stratigraphic column in the Chattanooga shale study area

System	Formation	Thickness	Outcrop area
Pennsylvanian	(Undivided)	1200 m +	Cumberland Plateau and Mountains
Mississippian	Pennington	45-120 m	Cumberland Plateau and Eastern Highland Rim
	Bangor and Hartselle	20-140 m	Eastern Highland Rim
	Monteagle	55-90 m	Northern, Eastern, and Southern Highland Rim
	St. Louis and Warsaw	55-90 m	All Highland Rim Quadrants
	Fort Payne	30-85 m	All Highland Rim Quadrants
	Maury	0.3-1.2 m	Highland Rim Escarpment
Devonian	Chattanooga	<3-10 m	Highland Rim Escarpment
Ordevician	(Undivided)	2000 m +	Central Basin

The major features of geologic structure within the study area are: the Nashville Dome, the Synclinal structure underlying the Cumberland Plateau and Cumberland Mountains, and the Black Warrior Basin.

The Nashville Dome is a broad gentle upwarped structure, the center of which lies in the Central Basin Region. Rock strata surrounding the Nashville Dome (on the Highland Rim) dip gently away from the structure -- east on the east flank, south on the south flank, etc. Dips in the Central Basin and Highland Rim areas are generally less than 5°. The Chattanooga shale dips about 2 to 3 m/km (10 to 15 ft/mile) in this region.

East and northeast of the Nashville Dome the easterly to southeasterly dip increases on the western limb of the Cumberland Mountain Syncline. Oil and gas well log information indicates that the Chattanooga shale occurs at about -580 m (-1900 ft) near the axis of this syncline beneath the Cumberland Mountains in Morgan County, Tennessee.

This shale outcrops along the base of the Cumberland Escarpment at the east edge of the study area and dips steeply to the northwest toward the axis of the syncline. In some areas along this outcrop belt, the shale has been removed and/or covered by faults.

The Sequatchie Anticline occurs within the Cumberland Plateau. This structure is a breached (faulted) anticline along which the Chattanooga shale is brought to the surface. Erosion has formed a long valley which extends from Tennessee into north central Alabama.

In north central Alabama, Paleozoic age rocks dip to the south into the Black Warrior Basin (also referred to as the Warrior Basin). The Sequatchie Anticline forms the eastern margin of the basin in Jackson, Marshall, and Blount Counties, Alabama. However, south of Blount County the Sequatchie Anticline plunges to the southwest, becoming a subsurface structure. The southernmost outcrop of the Chattanooga shale in Alabama occurs where the shale is brought to the surface in the Sequatchie Anticline in Blount County. The Chattanooga shale occurs at elevations ranging from near sea level to more than 1000 meters below sea level in the Black Warrior Basin.

Chattanooga shale consists of two major constituents, the Gassaway member and the Dowlletown member. The Gassaway member is the prime target

for multiple resource development. It exhibits classic black shale characteristics, petroliferous odor when broken, high organic content, and when weathered breaks down into very thin flakes. In general, this member is a massive black shale with little lithologic variation. The Gassaway member is commonly 3 to 5 m (10 to 15 ft) thick in the region of interest. Figure 3.2 from Conant and Swanson (1961) is a thickness map of the Gassaway member. The Gassaway is subdivided into upper, middle, and lower units. These subdivisions are based on the presence of several gray claystone layers interbedded with black shale in the middle of the Gassaway. The lower unit is composed of massive black shale with occasional phosphate nodules and very thin gray siltstone partings. The middle unit consists of a dark gray to black shale as described earlier with several interbedded, lighter colored claystones. The upper unit is similar to the shale in the lower unit. The upper 15 cm (0.5 ft) contains abundant phosphate nodules in a shale matrix.

The Dowelltown member of the Chattanooga shale is ~5 m (16 ft) thick and is subdivided into an upper and lower unit. The lower unit is a typical black shale which emits a petroliferous odor when broken. When weathered, it breaks into very thin fissile flakes. Interbedded with the organic-rich material are numerous very thin silt and clay-rich layers. The upper Dowelltown unit is a lighter colored, gray to dark gray sequence of alternating claystones and darker shales. A thin bentonite bed is found near the top of the upper Dowelltown unit (Hass, 1948). Conant and Swanson (1961) identified this bentonite bed as the Center Hill Bentonite. It is ~3 cm (0.1 ft) thick and was deposited over most of the study area.

3.1.3 Geochemistry and mineralogy

Quartz, clay minerals, pyrite, muscovite, and sericite are the major mineral constituents of the Chattanooga shale as determined by Rotinelly (1952). The above listed minerals comprise ~60% of the Chattanooga shale by volume; the remainder is described as kerogenous material. Bates and Strahl (1957) determined the primary clay mineral to be illite with smaller amounts of kaolinite and a total clay content of ~10%.

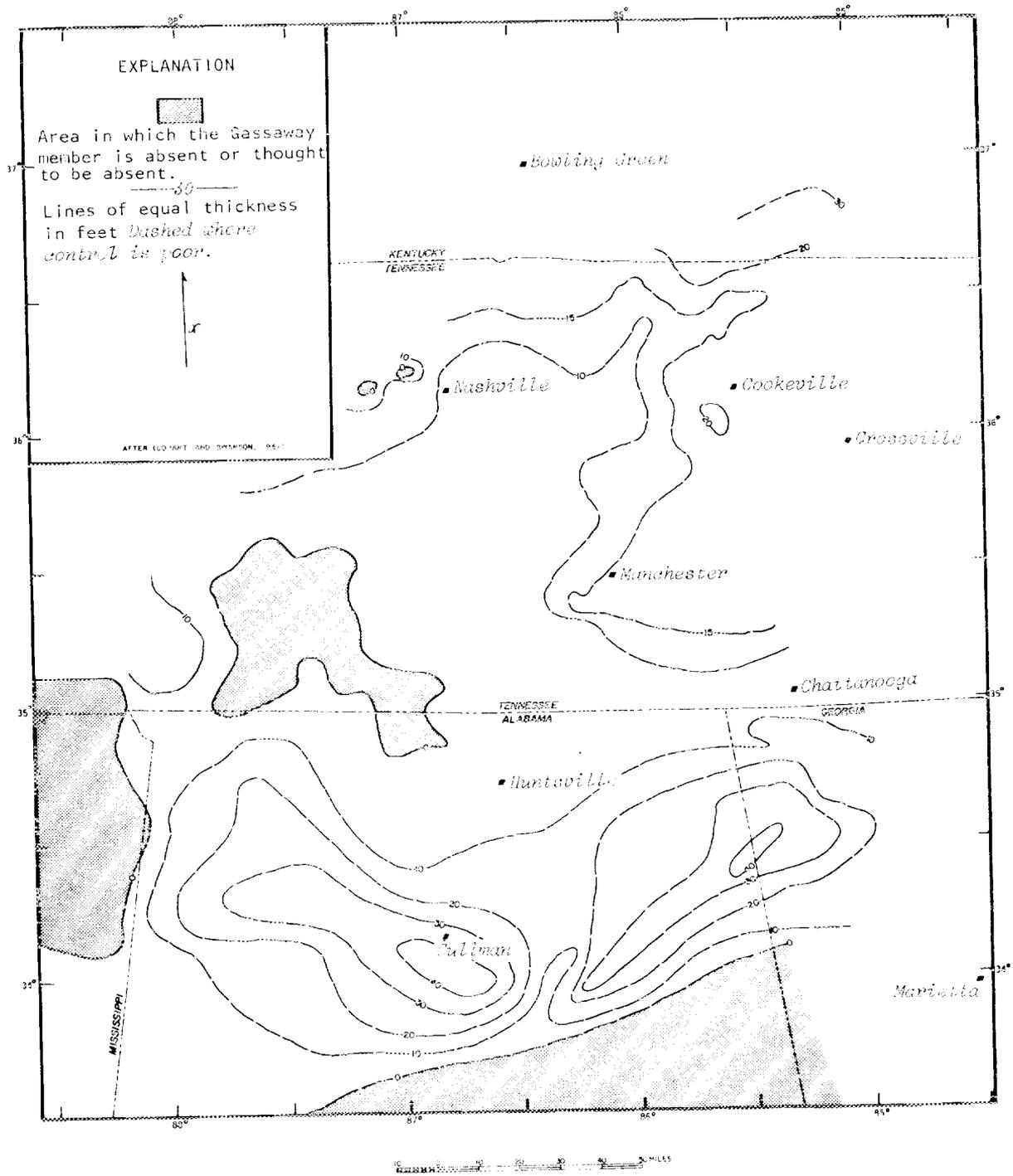


Fig. 3.2. Thickness of the Gassaway member of the Chattanooga shale.

The quartz content is ~25%, calcite 5%, and muscovite-sericite less than 5%. The pyrite content is of special interest because of environmental considerations and is estimated by Botinelly (1952) to be ~10% in the samples examined.

Many Chattanooga shale samples have been analyzed as a result of the various investigations of this unit as a potential uranium resource. A wide variety of analytical methods have been utilized over a 35-year period and comparisons are difficult in some cases. Uranium is the most commonly determined element in the Chattanooga shale and most of the values are from the upper unit of the Gassaway member. The Gassaway member consistently contains more uranium than the Doweiltown member. Values for the entire Gassaway member average ~50 ppm. The upper portion of the member averages ~65 ppm, and the middle and lower units average somewhat less than 60 ppm (Hickman and Lynch, 1967).

Organic carbon is a major chemical constituent of the Chattanooga shale with values up to 75% in thin coal or bitumen layers present at some localities. The organic carbon content provides not only a petroleum resource, but also a geochemical mechanism capable of concentrating several trace elements. Primary among these is uranium which is precipitated in the presence of a reductant (organic carbon) or adsorbed on surfaces of organic particles. Organic carbon concentrations in the Gassaway member vary over the area of interest but have frequently been observed to be of the order of 15% or more.

Mutschler (1976) indicates uranium concentration decreases north of DeKalb County and organic carbon content decreases southeast of DeKalb County. Oil yields can be expected to be higher north of DeKalb County in southern Kentucky, but uranium recovery would be lower. Little is known about how other elemental concentrations vary laterally within the Gassaway member of the Chattanooga shale. Most of the available data have been obtained in and around DeKalb County, Tennessee, and this area appears to be the most promising for initial resource recovery from the Gassaway. Greater thickness of Gassaway is present in northern Alabama, but 200 to 300 m of younger rocks overlie the Gassaway and preclude this area from consideration at this time.

Much of the area under consideration has not been evaluated thoroughly for a number of reasons. Among these are:

1. Available data are unfavorable with regard to carbon content.
2. Available data are unfavorable with regard to uranium concentration.
3. Overburden thickness is too great to allow for economic recovery of the resource.

Very few analyses of the trace minerals have been reported. It appeared to be desirable to obtain Chattanooga shale samples from several locations to determine the range of mineral concentrations which might be anticipated.

Analytical results of five core samples (provided by H. W. Leimer of the Tennessee Technological University) from Warren, DeKalb, White, and Putnam Counties are listed in Table 3.2 and in Appendix A. The thicknesses of the core samples are listed in Table 3.3. These analyses indicate that, while there is considerable variability in the samples, organic carbon was well above 10% in each Gassaway member (Tennessee Technological University, 1981) and valuable and strategic minerals were always present. On the other hand, none of the minerals was observed in concentrations of current commercial interest.

Further investigations of the Gassaway member should include definition of a favorable area based on elemental concentrations, oil yields, mining consideration, and environmental considerations. Once such an area has been defined, a detailed drilling and sampling program should be carried out to delineate the best subareas within the favorable area. Core samples should be used in determining elemental analyses because outcrop samples do not reflect elemental concentrations found in unweathered rock. Sampling of the core should be done in a consistent manner to assure the consistency of the analytical results. Uranium values and, to a lesser extent, carbon values are quite well established for the Gassaway; however, multielement analyses would be a large part of the analytical program.

Table 3.2. Mineral content of Chattanooga shale samples ^{a,b}

	Gassaway			Dowelltown	
	Upper	Middle	Lower	Upper	Lower
Percent					
Al	3,5,7	6,7,9	6,6,7	7,9,9	6,7,9
C (organic)	13,14,16	7,9,9	12,14,17	2,2,4	5,10,13
Fe	2,6,8	4,5,5	5,5,5	3,3,5	3,4,5
K	1,2,3	2,3,3	2,2,3	3,3,3	2,2,3
S	3,6,8	4,4,5	4,4,5	1,2,2	2,3,4
SiO ₂	49,53,56	58,60,63	52,54,56	54,60,63	53,56,62
PPM					
Co	10,48,90	20,35,40	40,42,50	30,39,110	20,25,40
Cr	60,98,150	100,103,130	100,107,130	90,108,120	120,142,150
Cu	90,122,200	110,118,130	160,176,190	80,94,110	170,192,220
Mn	140,156,170	160,216,360	170,208,250	190,340,460	120,266,330
Mo	40,174,270	20,107,140	120,152,180	10,30,100	20,129,180
Ni	90,213,400	90,137,160	140,154,170	60,88,130	100,222,290
Ti	1500,2420,2900	3000,3380,4100	2600,2960,3300	3400,3900,4400	2900,3360,4000
U	30,65,90	10,40,50	50,63,75	10,16,40	10,37,45
V	190,360,890	200,234,260	210,232,250	170,210,250	210,622,890
Zn	160,370,660	170,190,220	190,204,220	110,152,190	210,394,600

^aCarbon and S analyses were reported by Tennessee Technological University, 1981. Other analyses were performed by UCCND as part of the assessment project.

^bThe three numbers listed represent the minimum, average, and maximum concentrations, respectively.

Table 3.3. Thickness of Chattanooga shale core samples, ft^a

	Minimum	Average	Maximum
Gassaway			
Upper	3.8	8.0	12.2
Middle	2.2	3.5	5.3
Lower	2.9	5.4	8.9
Total	14.5	16.9	21.3
Dowelltown			
Upper	4.0	7.9	10.0
Lower	3.8	5.6	7.7
Total	7.8	13.5	17.7
Total Chattanooga	26.5	30.4	34.2

^a Reported by Tennessee Technological University, 1981.

3.2 Regional Setting

The discussion of regional setting includes a description of the regional environment, the socioeconomic setting, and some alternative scenarios for development.

3.2.1 Existing environment

Land use in the Chattanooga Shale Region is differentiated into broad patterns and closely associated with the physiography of the land. Both the Western Highland Rim and the Cumberland Plateau are heavily forested. In contrast, most of the land in the Central Basin, the Southern Highland Rim and the Pennyroyal (Mississippian Plateau) is cleared for agriculture, exhibiting various patterns of cropland and pasture. The Eastern Highland Rim exhibits a mix of agriculture and forest. Urban land use is mainly confined to the areas surrounding the three major cities of the region - Nashville, Chattanooga, and Huntsville. Small communities are also dispersed throughout the region. Minor classifications of land use, such as recreation, are significant to the economy of the region; however, the total area encompassed by these land uses is not great.

The Chattanooga Shale Region is characterized by a relatively mild and pleasant climate interrupted by long summer hot spells and variable winter outbreaks of freezing cold. Climate variation within the region is determined primarily by latitudinal differences and secondarily by differences in elevation. Average annual temperature is 14.8°C and average annual precipitation is 131.5 cm. About half the precipitation falls as rain or snow from December through March, when large-scale synoptic systems traverse the area; most of the remainder falls from March through September with a maximum in mid-summer, primarily as a result of thunderstorms. September and October are relatively dry. Average annual wind speeds are around 3 to 4 m/sec (7 to 9 mph) with maximum speeds in March and minimum speeds in August. Strong winds associated with tornadoes, hurricanes, or blizzards are infrequent compared to most other areas of the country. Poor dispersive conditions, producing a high meteorological

potential for air pollution, occur frequently in the region compared to most of the rest of the eastern United States. Low-level (below 150 m) temperature inversions exist about 45% of the time with little gross seasonal variation. Existing ambient air quality in the Chattanooga Oil Shale Region is generally moderate for pollutants which have been monitored.

The vegetation of the region reflects the influence of 200 years of settlement. The original vegetation has been cleared or modified such that it no longer reflects physiographic control. Predominant vegetation continues to be broad-leafed, deciduous forest with mixtures of coniferous trees, however. The faunal component of the region has been relatively enriched in those species which thrive in a mosaic of forests and fields.

The aquatic biota of the region is highly diverse due to the great diversity of habitats. Creation of reservoirs within the last 45 years has decreased diversity and increased the relative frequency of species adapted to deeper, slower waters. Seven terrestrial animal species, three terrestrial plant species, and nineteen aquatic species appearing on the U.S. Fish and Wildlife Service Endangered Species lists occur within the region.

Important water resources in the region occur both as surface water and groundwater. Groundwater is an important source of potable water for municipal and private water supplies throughout the Chattanooga shale resource area. Groundwater occurs in alluvial aquifers adjacent to the major streams and rivers in the area, in soil or weathered rock residuum, and in solution cavities in the carbonate bedrock of the region. Alluvial aquifers are not extensively utilized as a source of water because of the more general occurrence of soil and bedrock aquifers.

Soil aquifers occur where sufficient thicknesses of soil and weathered rock residuum have accumulated above the bedrock surface. Aquifers of this type are sporadically distributed throughout the region. Soil aquifers are most likely to develop above bedrock which leaves large volumes of residue upon weathering. Thick residual deposits form in the outcrop zone of the Fort Payne formation because of its high chert content. Other rock units within the Highland Rim and Central Basin areas tend not

to form such thick residual deposits as does the Fort Payne. Soil aquifers may interconnect with underlying bedrock aquifers. The probability of occurrence of soil aquifers is highest on slopes in draws or small stream valleys where infiltrating runoff naturally accumulates.

Aquifers in bedrock of the Highland Rim and Central Basin typically consist of water filled solution cavities in the carbonate bedrock. On the Highland Rim the predominant bedrock aquifers occur in the Fort Payne, Warsaw, and St. Louis formations. The Fort Payne formation forms an outcrop band as much as 25 km wide along the Highland Rim Escarpment. Within this outcrop band, the bedrock and overlying residuum locally contain an aquifer which supplies most water used either through wells, springs, or by supplying the base flow to streams which are used as water resources.

In order to predict the effects of mining beneath the aquifer, the vertical position of the aquifer must be known. If the base of the aquifer rests on the Maury and Chattanooga shales, undermining would result in dewatering of portions of the aquifer. In areas where the basal portion of the Fort Payne is unweathered and unfractured, undermining would not be expected to damage the aquifer unless subsidence caused failure of the basal aquiclude. Areas in which porous zones penetrate to the base of the Fort Payne cannot presently be identified.

Groundwater quality in the Chattanooga shale study area is variable. In most areas the water is hard to very hard. Most analyses indicate that the groundwater is predominantly a calcium bicarbonate type, though in a few areas sodium, chloride, and sulfate are present in high concentrations. Concentrations of iron, manganese, hydrogen sulfide, and natural gas adversely affect water quality in some areas particularly where water is obtained from bedrock openings. Water obtained from the soil aquifer overlying the Fort Payne formation is less likely to contain nuisance quantities of these constituents.

Occurrence of surface water in the Chattanooga Shale Region is attributable to runoff (annual av. ~20 cm) of local precipitation (av. ~100 cm/year), discharge of groundwater, and stream inflow. The surface water supply is subject to natural depletion from infiltration, evaporation, transpiration, and outflow from the area via streams and rivers. Low flow

in this region occurs during fall, while high flow occurs during the spring. Generally rainfall recharges the groundwater system which slowly releases water from the underground stream to sustain surface water flow.

The lowest stream flow in the assessment region usually occurs in September or October but may occur during any one year between June and December. The low flow of this area ranges from 5×10^{-4} to 4×10^{-3} $m^3/s/km^2$ for 7-day 10-year recurrence intervals. The limited low-flow yield reflects the shallowness of the soil mantle, the slow percolation rate through the cherty soil and the relatively poor water-bearing properties of the underlying shale in portions of the region.

Flood flow is controlled by frequency, amount, and duration of rainfall, the topography of the watersheds, the underlying strata, the configuration, and the extent of modification of the watershed. Based on gaging station records, the majority of floods (>60%) in this region occur January through March with ~30% of the remaining flood flow occurring April through September.

Water quality in the Chattanooga shale assessment region is suitable for most uses. Sodium, potassium, chloride, fluoride, nitrate, and sulfate are generally present in limited quantities in streams in these regions. Surface waters in the Tennessee Water Resources Region contain calcium and bicarbonate as the most common minerals because of contact of both surface and subsurface waters with limestone and cherty limestone.

Although dissolved oxygen concentrations generally are in excess of 8 mg/L in the major river systems in the Chattanooga Shale Region, some of the reservoirs experience levels below the 5 mg/L criterion for fish and aquatic life for 1 to 5 months each year. These low levels occur as the result of the depletion of oxygen below the thermocline of hypolimnetic releases from upstream reservoirs. Dissolved solids are typically in the 120 to 150 ppm range, with drainage from the western slope of the Appalachians generally having levels less than 120 ppm.

Generally, surface water quality of streams in the Chattanooga Shale Region meets the chemical standards recommended for drinking water. In some cases, however, the levels of dissolved solids exceeds 500 mg/L and iron may exceed 0.3 mg/L. Increased levels of manganese may also occur

(>0.3 mg/L) when there are increased levels of iron. Although surface water hardness ranges from soft (<75 mg/L) to hard (>150 mg/L), hardness in most of the larger streams exceeds 100 mg/L. This property does not limit water use in this region but may require treatment to reduce hardness prior to use in cooling systems or boilers in order to prevent scaling.

In terms of present water use and water availability, both surficial and underground, the Chattanooga Shale Region is capable of supporting the growth of water consumptive industries. Water consumption uses only a fraction of the surface and groundwater available on a year round basis. More significantly, the water use for the region consumes only a small percentage of the critical low flow. Water consumption during the critical-low-flow month could increase ~10 times before it could possibly be identified as a potential low-flow water shortage problem area.

3.2.2 Socioeconomics

The socioeconomic environment is clearly divided between the urban areas (e.g., Nashville and Chattanooga) and the rural areas (e.g., DeKalb County). Urban areas are experiencing growth by immigration while rural areas contain a population age structure suggesting emigration of a substantial portion of their young people.

The region has enjoyed considerable economic growth with urban areas having per capita incomes above the national average. Manufacturing has surpassed agriculture in importance in rural areas but rural per capita income remains below the national average and 40% of the counties have been declared to be surplus labor areas.

Rural areas have a relatively high frequency of substandard housing, averaging 12% in the outcrop counties. All outcrop counties have medical care available although hospitalization may require travel outside the county. Public education from kindergarten through twelfth grade is available in all counties; and specialized schools, vocational-technical schools, and institutions for higher education are available in the region, if not the home county.

Total tax revenues are proportional to county population with an average of 26% of revenues coming from local taxes with the remainder coming from state and federal sources. In general, urban counties raise a greater portion of revenues locally (48% in Davidson County). Local taxes are low compared to national averages.

3.2.3 Chattanooga shale development scenarios

The scale, location, and timing of Chattanooga shale development is unpredictable. Scale and location of processing facilities would be partially dictated by the following factors:

- * optimum process facility size,
- * availability of sites having access to mineable shale, adequate water supplies, and the transportation network,
- * permanent labor force availability,
- * environmental constraints.

Establishment of the oil shale industry requires simultaneous development of the processing units and mines to supply the feedstock. Several development scenarios are possible.

1. A total mine mouth type operation with one owner/operator running the entire mining and processing operation. The scale of this type operation is assumed to be on the order of 90,000 Mg/d shale mining and processing with ~8,000 m³/d (50,000 BPD) oil produced.
2. An operation in which a central processing facility receives and processes shale from a number of mines within a local area. The processing facility is assumed to handle 90,000 Mg/d of shale and produces 8,000 m³/d of oil. Mining may be entirely independently operated or mineral leases may be owned by the processing plant.
3. Dispersed development of the processing and mining activities. Under this scenario the processing centers are envisioned as being of variable size and perhaps none of these facilities would be as large as

those considered in the preceding facility. Historically, this type of development has been typical of development of nonmetallic mineral resources of the region.

These three scenarios are used throughout the environmental assessment on Chattanooga shale development. Some development of each type may ultimately occur depending on the viability of different types of shale processing technologies.

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4. MINING AND SOLID WASTE DISPOSAL

It is the purpose of this chapter to summarize and assess the available information on mining and waste disposal activities applicable to the Chattanooga shale. Factors which determine the feasibility of mining the shale are identified, potential reserves within reach of proposed underground mines are tabulated, and the feasibility of surface mining at outcrop is evaluated. Key factors in the management of solid wastes are discussed and options for long-term disposal of solid wastes are evaluated in terms of the advantages and disadvantages of each option. Reclamation of areas affected by shale development and the existing regulatory framework governing solid waste disposal at federal and state levels are discussed.

4.1 Mining Feasibility

The discussion of mining feasibility, in the sense of this region-wide assessment, is a generic discussion of factors which will affect mining of the shale resource. A strict mining feasibility study proposes a specific mine plan for a particular tract of land on which exploratory work has been completed. Rather than providing a site-specific feasibility study, this assessment will identify areas where the shale resource has the best potential for economic development, provide rough estimates of in-place shale tonnages, and identify geologic aspects of the region which will affect shale development.

4.1.1 Resource distribution

The region considered in this study is shown in Fig. 4.1. Development of mines in the Chattanooga shale depends on the selection of mineral tracts having thicknesses of shale of sufficient hydrocarbon and metallic content to profitably mine and process the shale.

The Gassaway member of the shale appears to be more attractive for mine development than the Dowelltown because of its geochemical character.

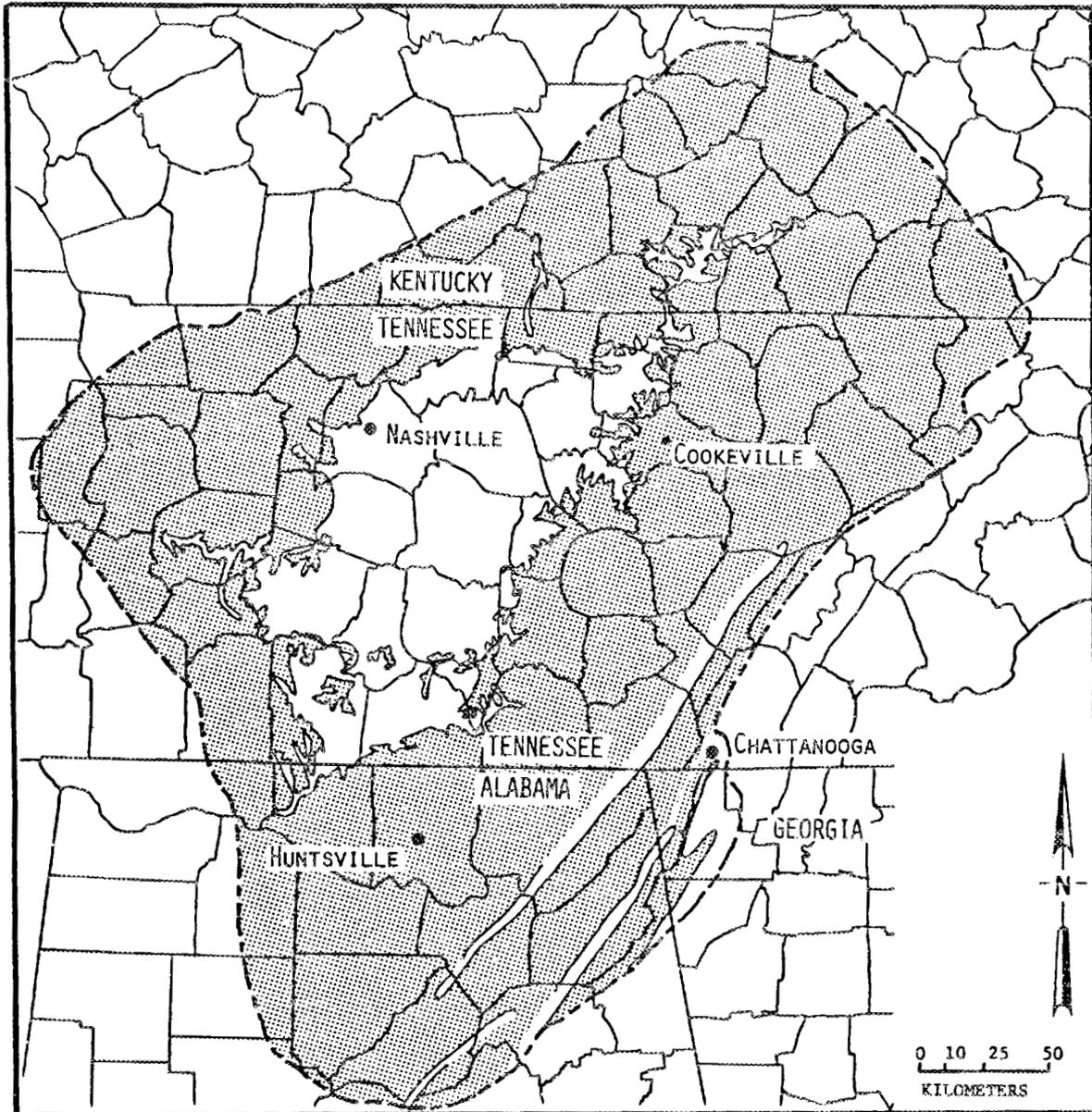


Fig. 4.1. The Chattanooga shale region. Stippled areas are underlain by the Chattanooga shale.

A thickness of 3 m of the Gassaway member was suggested as the minimum mineable thickness (Mountain States, 1978). The Mountain States mine plan indicates that reserves within about 8 km of the mine mouth could be recovered. A mine producing 32,650 metric tons/d is expected to recover shale from an area of about 5 x 8 km within a 20-year period of operation. Entry could be made at the shale outcrop or by construction of a slope entry in areas where the overburden is of appropriate thickness and could safely support the driven tunnel required for slope entry. Areas with greater than a 3 m thickness of the Gassaway member and lying within 8 km of the outcrop are shown in Fig. 4.2. These areas would logically be the easiest to develop because of the accessibility of the shale.

A geologic cross section between Lebanon and Clinton, Tennessee, is shown in Fig. 4.3. Data from which the geologic cross section was drawn came from oil and gas well records which are available from the Tennessee Division of Geology. These data were first plotted as a geologic structure contour map on the top of the Chattanooga shale and then transformed to the cross section. The cross section shows that near the outcrop on the Eastern Highland Rim the shale is nearly lying flat and is comparatively close to the surface. Beneath the Cumberland Plateau the southeasterly dip steepens on the western limb of an asymmetrical syncline. The axis of the SW-NE trending syncline lies beneath the Cumberland Mountains and is thought to plunge gently to the NE. The area within 8 km of outcrop (from Fig. 4.2) is also shown on Fig. 4.3. It may be possible to develop areas beneath the Eastern Highland Rim by a slope entry if developable reserves are proven to exist in that area. Access to shale reserves beneath the Cumberland Plateau and Cumberland Mountains requires greater development expense because of the depth at which the shale lies and steeper dip of the shale caused by the geologic structure in the area.

As shown in Fig. 4.1, the Chattanooga shale outcrops in several counties in northern and northeastern Alabama. Shale thicknesses measured at outcrops in Lauderdale, Limestone, and Madison Counties, Alabama, range up to 1 m. Drilling logs indicate a thickening trend in the southern parts of these counties; this trend continues to the south and southeast into

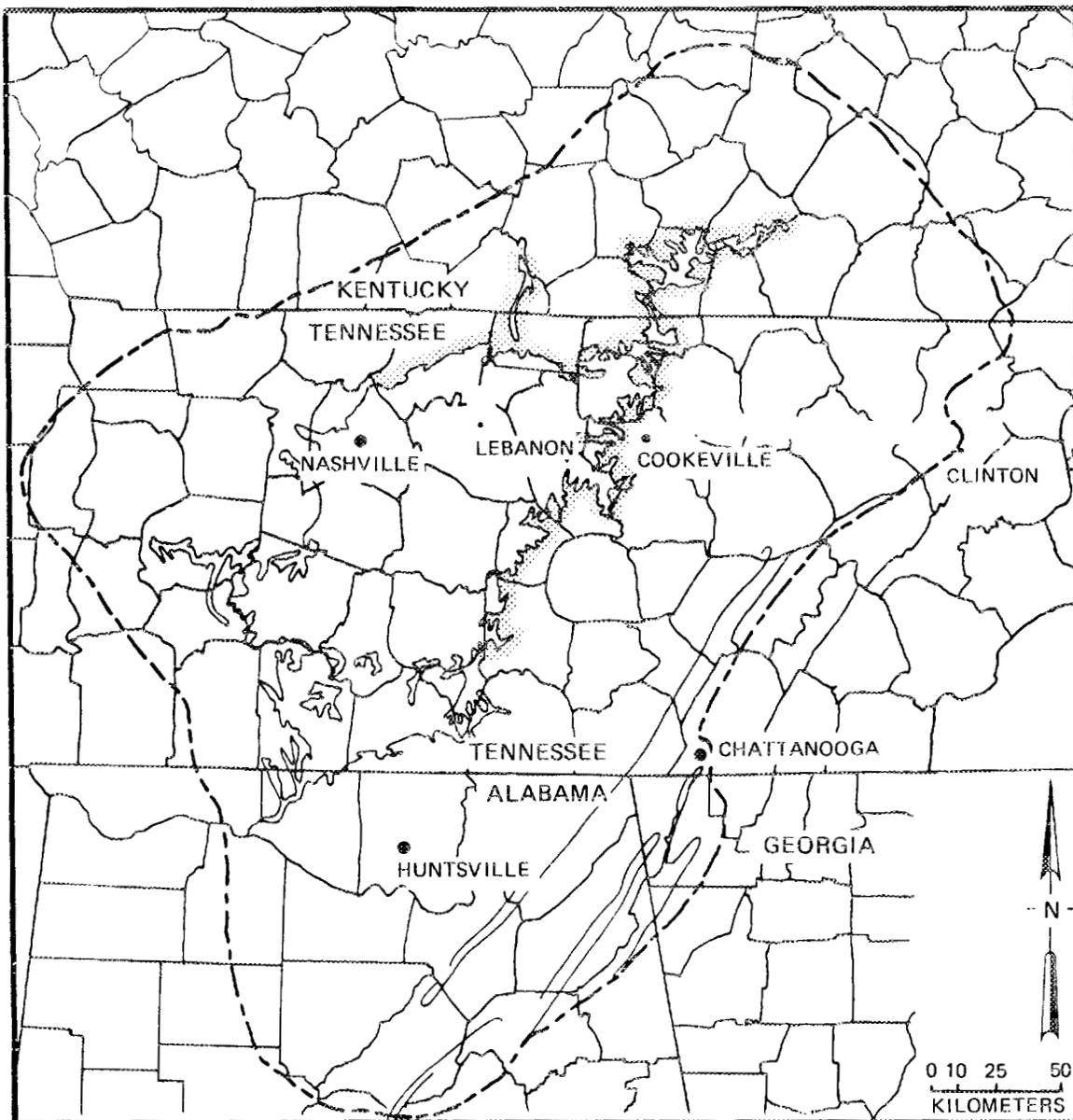


Fig. 4.2. Approximate geographic boundaries of the Chattanooga shale. The shaded area, extending 8 km from the line of outcrops, is the most accessible for mining.

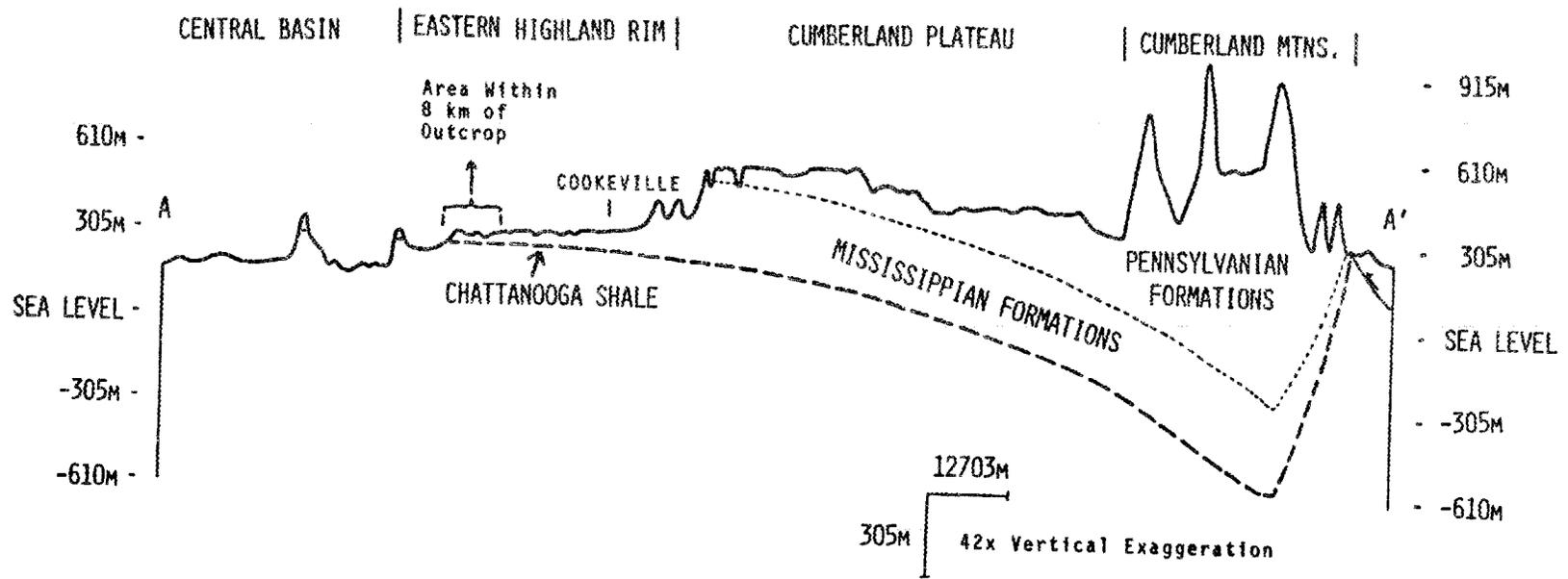


Fig. 4.3. Geologic cross section between Lebanon and Clinton, Tennessee.

the Warrior Basin. The Gassaway member reaches thicknesses in excess of 12.2 m in Cullman and Blount Counties.

Structure contours drawn on top of the Fort Payne in the Warrior Basin show that the Chattanooga dips to the south southwest at about 100 m/km (Thomas, 1972). The 12 m thick shale previously mentioned lies approximately 200 to 800 m below the surface. Access to the shale would require a vertical shaft entry. Additional developmental drilling and testing would be required to determine whether the resource is worthy of development in this area, since the only reported sample from Alabama yielded 2.9 l/metric ton in the Fischer Assay.

In northeast Alabama the Gassaway member reaches thicknesses of about 12.2 m in Cherokee and DeKalb Counties. In this part of the state the shale lies in broad synclinal folds which underlie Sand Mountain and Lookout Mountain. Locally, low angle thrust faults have occurred in the shale in these areas, causing the shale to thin and thicken erratically. The hydrocarbon content of the shale in these areas is unknown.

4.1.2. Geologic factors of significance to mine planning

The following geologic factors will have to be considered in planning any mines in the Chattanooga shale:

- thickness and structure of potentially mineable horizons,
- stability of overlying strata,
- accessibility of the reserves, and
- control of groundwater.

Thickness will affect the selection of mining methods. Both thickness and geologic structure will affect mine layout and operations planning. These factors are discussed in previous paragraphs. At any specific locality, thickness and geologic structure must be determined by a developmental drilling phase which provides data on a close spacing for mine planning.

The stability of strata overlying the shale must be determined for areas to be mined. The Maury shale is not expected to stand as a roof rock and, therefore, will be removed with the shale unless a portion of

the Gassaway is left as the roof rock. When mined with the Chattanooga, the Maury will act as a diluent in the shale fed to the processing plant. The Maury averages 0.5 to 0.9 m thick (Stockdale and Klepser, 1959) and would dilute mined shale from a 3-m ore zone by a factor of 15 to 30%. Dilution by inclusion of the Maury when mining thicker sections of the Gassaway would be proportionately less. The Fort Payne formation, which overlies the Maury, is described as being strongly jointed (Brown, 1975). In some areas closely spaced joints might cause roof instability; these areas could be detected in development drilling and avoided in the mine plan.

Mines can be economically developed only where the shale is accessible. Mines which enter at the outcrop are expected to recover shale within several miles of the outcrop. Additional reserves beneath the Highland Rim and the western edge of the Cumberland Plateau would be accessible by driving slopes or vertical shafts into the shale. The resource potential of shale beneath the Cumberland Plateau and Mountains is largely unknown. Access to these areas will be sufficiently difficult due to the depth to the shale that these areas will be developed after more accessible shale has been mined out (see Fig. 4.3).

Mining the Chattanooga shale probably will affect local groundwater conditions. The Fort Payne contains an aquifer which supplies drinking water to most rural residences and to many communities on the Eastern Highland Rim. The Maury and Chattanooga shales act as an aquiclude below the Fort Payne. Undermining areas where the aquifer directly overlies the shale will allow water to flow into the mines through fractures and solution openings. The result will be lowered water tables around the mined areas. Inflowing water must be pumped out of the mines to prevent flooding. This water may also require treatment by sedimentation or other means before it is discharged to surface streams or reinjected.

4.1.3 Hydrocarbon potential of the Chattanooga shale

The Fischer Assay is commonly used as an indicator of oil yield of shale samples for conventional retorting. The Mountain States Report included a figure showing Fischer Assay oil yields for samples taken from

the Gassaway member within the study area. The same figure is reproduced in this report as Fig. 4.4. Bench scale hydroretort testing at the Institute of Gas Technology has resulted in oil yields of up to 2.5 times the Fischer Assay yield for samples of the New Albany shale from Kentucky (Feldkirchner, 1979). It is not known what increase in oil yield can be expected from a commercial scale hydroretort operating with run-of-mine feedstock. The average Fischer Assay oil yield obtained from four drill cores from DeKalb County, Tennessee, and one core from White County, Tennessee, is 40.65 L/metric ton of shale (determined from data of Mutschler 1976). If hydroretorting can increase oil production by a factor of 1.5 to 2 times the Fischer Assay yield, reserves in Dekalb County would be expected to produce 60.9 to 81.4 L/metric ton (14.6 to 19.5 gal/ton) of shale.

The effect of weathering on Chattanooga shale oil yield was evaluated by Brown (1975). Fischer Assay oil yield and oil/water ratios from tests on closely spaced outcrop, road cut, and drill hole samples were compared. The effect of weathering is a reduction of oil yield; the amount of reduction depending on the degree of weathering. The result of Brown's comparison indicated that weathering has extended at least 10 m behind the outcrop. Therefore, samples are of no quantitative value when obtained from outcrops or from road cuts which have not exposed fresh shale. Many of the data points on Fig. 4.4 were obtained from outcrop and road cut samples which probably were weathered to some extent. Quantification of the effect of weathering on the yield at any specific sample locality on Fig. 4.4 is not possible due to lack of information on outcrop condition.

The available data indicated that

- the Northern Highland Rim, the central and northern parts of the Eastern Highland Rim, and south central Kentucky appear to hold the best potentially developable hydrocarbon resources,
- oil yields are low in samples from Walden Ridge,
- insufficient information is available to evaluate the hydrocarbon resource in Cullman, Blount, and Morgan Counties, Alabama, or in the northern Cumberland Plateau and Cumberland Mountains in Tennessee.

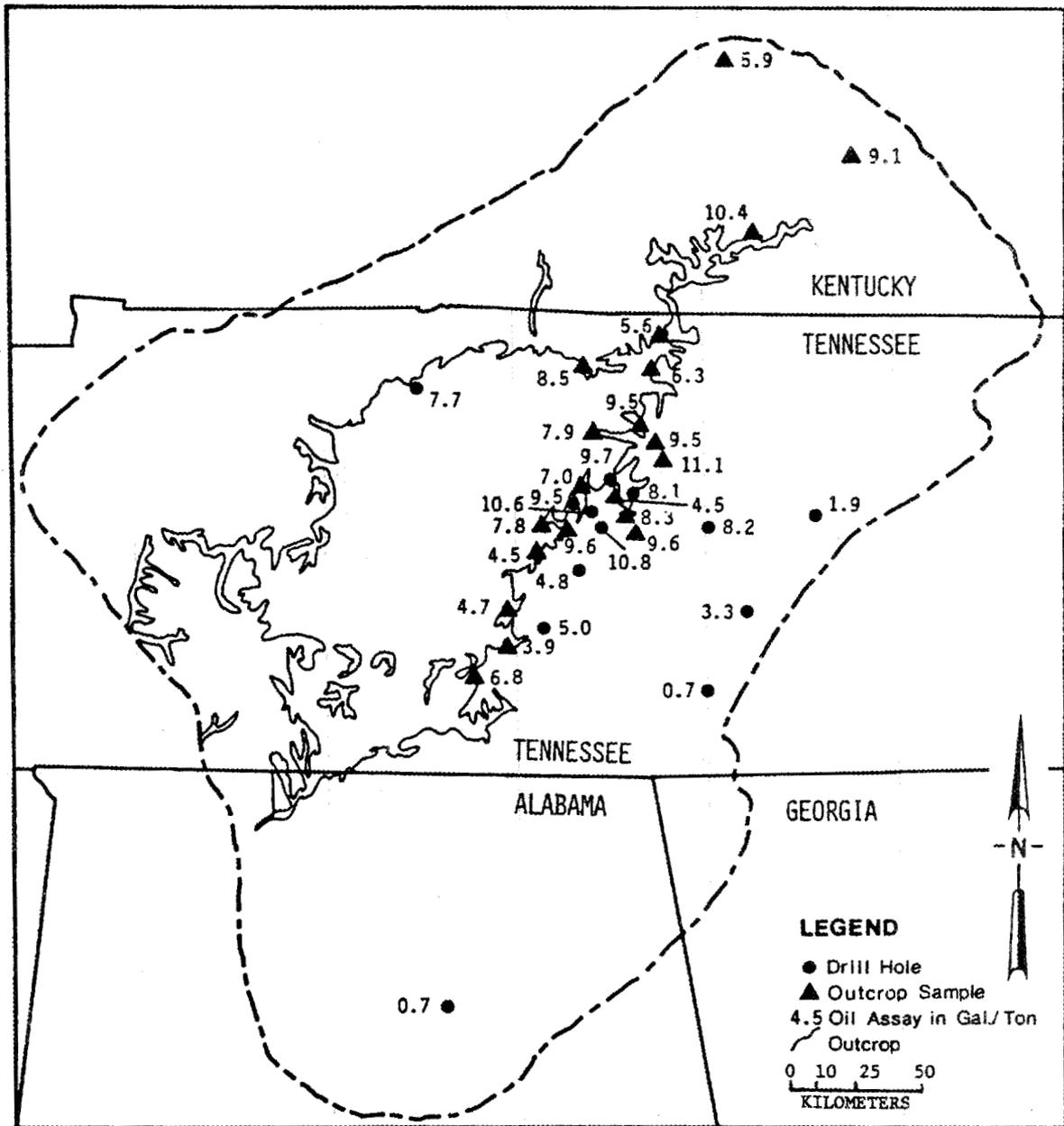


Fig. 4.4. Oil yield values for the Gassaway member of the Chattanooga shale (after Mutschler, Hill, and Williams, 1976).

Western oil shale reserves which are considered most attractive for development are expected to yield 104 to 167 l/metric ton (25 to 40 gal/ton) based on Fischer Assay analyses (Kash, 1976). Additional core drilling and testing of the Chattanooga shale will be required to demonstrate the potential for commercial hydrocarbon production and to identify target areas for development.

4.1.4 Chattanooga shale reserves

The extent of Chattanooga shale occurrence is shown in Fig. 4.1. Areas in Tennessee and Kentucky which have average Gassaway thicknesses greater than 3 m and are within about 8 km of the outcrop are shown in Fig. 4.2. A summary of approximate 'in place' tonnages, thicknesses, and acreages by counties for the reserves within 8 km of the outcrop is presented in Table 4.1. The percentage of in-place reserves which could ultimately be produced is dependent on local factors such as:

- * pillar size and spacing required for roof support [about 30 to 40% of the resource within the mine area for underground mines remains as pillars (Schmidt, 1979)],
- * availability of leasable reserves,
- * local configuration of towns, buildings or other areas beneath which mining could cause damaging subsidence,
- * geologic factors such as weak roof, faulting, groundwater, etc., which could prevent mining some areas.

Assuming that 50% of the in-place Gassaway shale can be recovered from this zone, the oil to be produced within 8 km of outcrop would be 18 billion barrels (0.5 bbl/ton). The uranium produced would be 2 million tons of U_3O_8 (60 ppm, 80% recovery).

While the shale near the outcrop would be the initial target for development, ultimately many times as much material would be accessible through deep mining. The resource has not been explored sufficiently to yield a definitive estimate of reserves.

The recovery factor for underground mining of the total coal reserve base has been estimated (Schmidt, 1979) to be about 30% due to the factors

Table 4.1. Approximate in-place reserves of Gassaway member within 8 km of outcrop areas with shale greater than 3 m

State, County	Approximate ^a area (ha) within 8 km of outcrop	Average ^b Gassaway thickness (m)	Approximate in-place tonnage metric tons x 10 ⁶
<u>Tennessee</u>			
Davidson	23,600	3.56	2000
Robertson	7,600	3.96	725
Sumner	46,000	4.57	4700
Macon	38,000	3.96	3600
Clay	46,800	4.57	4900
Overton	29,200	4.88	3300
Jackson	28,800	4.88	3400
Putnam	40,000	5.49	5200
White	18,400	5.79	2400
DeKalb	38,400	4.57	4100
Cannon	28,400	3.96	2500
Coffee, Franklin, Moore	68,400	3.96	6500
SUBTOTAL			4.3 x 10 ¹⁰ metric tons
<u>Kentucky</u>			
Allen	40,000	4.88	4500
Barren	21,600	4.88	2000
Monroe	8,800	5.18	1100
Metcalf	22,800	Unknown	Unknown
Cumberland	50,000	7.62	8800
Adair	14,800	7.62	2600
Russell	16,400	9.15	3500
Clinton	15,600	6.10	2300
SUBTOTAL			2.5 x 10 ¹⁰ metric tons
TOTAL			6.8 x 10 ¹⁰ metric tons

^a Acreages were measured on 1:500,000 scale outcrop maps.

^b Gassaway member thicknesses are averages of data published in USGS Professional Paper 357 by Conant and Swanson, 1961.

listed above. Assuming that a similar proportion of the land within the Chattanooga shale resource area might be unmineable, the producible tonnages may be about one-third of the in-place tonnages.

4.1.5 Chattanooga shale mining methods

The choice of mining methods for extraction of Devonian shales depends on shale thickness and grade and on the character of overburden or roof rock which overlies the shale. The Chattanooga shale in Tennessee, northern Alabama, and south central Kentucky is overlain by the Maury shale (0.5 to 0.9 m) and the Fort Payne formation (30 to 60 m) which, in most outcrops, is predominantly a thin-to-medium-bedded, cherty dolostone or limestone.

The only known mining plan for extraction of the Chattanooga shale in Tennessee was prepared by Cleveland Cliffs Mining Company and is included in the Mountain States Report. The mine plan describes the procedures for developing three large, 30,000 Mg/d underground mines which supply a 90,000 Mg/d shale processing facility.

Factors which must be considered in selecting surface vs. underground mining methods include: overburden thickness, lateral extent of the deposit, physical properties of overburden (e.g., Will overburden serve as a roof rock for underground mining? Is the overburden amenable to excavation?), resource recovery efficiency, production costs, and environmental constraints. The general character of overburden in the study region is not favorable for area type surface mining due to excessive thickness and toughness. However, a contour type strip mine along outcrops may be feasible in some areas. The Fort Payne formation is expected to provide a competent roof in most areas. In some localized areas, the basal portions of the Fort Payne is shale which may lead to weak or unstable roof conditions. The locations of these areas are not accurately known.

Previous underground mining experience in Chattanooga shale -- Previous experience with mining the Chattanooga shale is limited to the excavation of an adit near Sligo in DeKalb County, Tennessee, in 1947-1948. The adit was excavated to provide large (12 to 15 ton) samples of

the shale and to provide information on mining conditions. The adit was excavated in the topmost unit of the Gassaway member and the Maury shale was also removed in most places. Dimensions of the adit were 1.5 to 2 m (5 to 7 ft) wide x 2.5 m (8.5 ft) high x 30 m (100 ft) long. Details of this excavation are reported by Brown (1975). Brown's report includes primarily information on the blasting methods which were used, a survey of the adit, and description of the jointing patterns. The adit excavation was performed by manual labor with the exception of drilling and blasting and no information is available from which to estimate mining costs.

Surface mining potential of Chattanooga shale -- Surface mining costs generally are less than underground mining costs. The ratio of overburden removed to resource recovered (the stripping ratio) determines the maximum thickness of overburden which can be economically removed. Two approaches may be used to determine the approximate stripping ratio for a typical outcrop of Chattanooga shale. One approach is to estimate mining and processing costs and product values. This requires reasonably detailed estimates of the overall processing costs and capital investment analyses which are not yet available. The approach used here is application of surface mining economics of coal strip mining in the Appalachian area to shale mining. This procedure does not evaluate the effect of market value on mining economics and provides only a rough estimate of the surface mining potential.

Deriving stripping ratios for the Chattanooga shale by analogy to Appalachian coal strip mining economics involves comparison of two very different hydrocarbon resources. A stripping ratio of 12:1 is commonly used in contour strip mines in Appalachia. Area mines, which use draglines or bucket wheel overburden excavators, can operate on stripping ratios greater than 20:1. The machinery used in area mining is generally not adaptable to contour mining especially on steep slopes. Area mining equipment is well suited for excavation of comparatively soft or friable overburden materials. The tough Fort Payne formation which overlies the Chattanooga and Maury shales in Tennessee would require blasting and handling with conventional contour mining equipment. Some areas in the Northern Highland Rim and in central Kentucky, where shale is the predominant

overburden, may be amenable to development using larger area mining equipment.

Preliminary calculations of highwall and pit dimensions for contour mining of the Chattanooga shale are presented in the following paragraphs. These estimates are considered rough approximations since local geologic and topographic conditions at any specific mine site will determine the actual economics of shale extraction.

The following conditions define the basis for estimating the production potential by surface mining of shale in central Tennessee.

The average energy per pound of coal = 2.67×10^7 J/kg [$\sim 11,500$ Btu/lb (Minerals Yearbook, 1976)]

The average stripping ratio* = $10.52 \text{ m}^3/\text{metric ton}$ (12 yd^3 overburden/ton) coal

2.67×10^7 J/kg ($11,500$ Btu/lb) = 2.67×10^{10} J/metric ton (23×10^6 Btu/ton) coal

$$\frac{2.67 \times 10^{10} \text{ J/metric ton}}{10.52 \text{ m}^3/\text{metric ton overburden}} = \frac{23 \times 10^6 \text{ Btu/ton}}{12 \text{ yd}^3 \text{ overburden}}$$

= 2.54×10^9 J/m³ overburden removed (1.9×10^6 Btu/yd³ overburden removed).

Btu ratings of the shale are not directly available, so the following assumptions are made. The product oil is assumed to be 30° API gravity oil (Feldkirchner, 1979). If 83.5 L/metric ton (20 gal/tons) of 30° API gravity oil (132,000 Btu/gal) is recovered from shale by hydrotreating, the shale would have 3.07×10^9 J/metric ton (2.64×10^6 Btu/ton or 1320 Btu/lb) marketable hydrocarbon. Additional carbon conversion would provide energy for part of the processing heat requirements.

The stripping ratio for shale (at 2.64 million Btu/ton), which is equivalent to a 12:1 ratio for coal, is determined by dividing the available energy per volume of shale by the overburden removal cost for mining (in terms of energy produced per volume of overburden removed).

*Higher Btu/lb coal could be mined to a higher stripping ratio because of higher product value. Lower Btu/lb coal would be mined using a somewhat lower stripping ratio.

$$\frac{3.07 \times 10^9 \text{ J/metric ton}}{2.54 \times 10^9 \text{ J/m}^3} = \frac{2.64 \times 10^6 \text{ Btu/ton shale}}{1.9 \times 10^6 \text{ Btu prod/yd}^3 \text{ OB}}$$

= 1.21 m³ overburden/metric ton shale (1.39 yd³ overburden/ton shale).

Given the density of undisturbed shale as 2.3 g/cm³, there are 2.3 metric tons/m³ (3,115 tons/acre-ft) of shale in place. A 3 m thick resource zone bears 69,000 metric tons/ha (31,150 tons per acre). Average and maximum highwall heights for shale yielding 41.7, 52.2, 62.3, 73.0 and 83.5 L/metric ton (10, 12.5, 15.0, 17.5, and 20 gal/ton) and shale thicknesses of 3.05 m, 3.66 m, 4.26 m, 4.88 m, and 5.48 m are included in Table 4.2.

These computations are based only on conversion of the organic carbon to a petroleum fuel and do not include any consideration of recovery of metals or residual carbon which may be recovered by further processing. The 83.5 L/metric ton (20 gal/ton) yield gives some idea what the surface mining potential might be if conventional retorting is used. Higher oil yields, potentially obtainable by hydroretorting, would increase the stripping ratio as shown in the table.

A geologic cross section of the Central Basin/Eastern Highland Rim boundary shows the occurrence of the shale in a typical, eroded, outcrop area (Fig. 4.5). Erosional outliers are found in areas where stream valleys have eroded the shale. In comparing estimates of strippable overburden thicknesses to those encountered in the outcrop zone, it is apparent that only a very small fraction of the potentially developable shale reserves could be recovered by surface mining methods (Fig. 4.5). The bulk of the shale resource will have to be mined using underground methods.

Strippable reserves - Key factors which determine surface mining feasibility have been discussed in the previous section. Rough estimates of potentially strippable reserves per kilometer of shale outcrop are presented in Table 4.3. This table follows the format of Table 4.1 and uses maximum highwall heights from Table 4.2. A slope angle of 20° at outcrop is assumed and the shale is essentially flat lying. A recovery factor of 90% is used [90% recovery is considered maximum recovery for contour coal strip mining (Schmidt, 1979)].

Table 4.2. Average^a/maximum^b overburden thicknesses (meters) for surface mining of Chattanooga shale: preliminary estimates

Oil yield, ^c liters/metric ton (gal/ton)	Thickness of Gassaway member				
	3.05 m	3.66 m	4.26 m	4.88 m	5.48 m
41.7 (10)	4.1/13.6	4.8/15.0	5.7/16.2	6.5/17.3	7.3/18.4
52.2 (12.5)	5.1/15.4	6.2/16.8	7.2/18.2	8.2/19.4	9.2/20.6
62.3 (15.0)	6.1/16.8	7.4/18.4	8.6/19.9	9.8/21.3	11.0/22.5
73.0 (17.5)	7.2/18.2	8.6/19.9	10.1/21.5	11.5/23.0	12.9/24.4
83.5 (20)	8.2/19.4	9.8/21.3	11.5/22.9	13.1/24.6	14.7/26.1

^a Average overburden thicknesses is the thickness which could be mined on a sustained box cut or area mining basis using 12:1 stripping ratio. Average values appear left of the slash.

^b Maximum overburden thickness is the maximum highwall cutoff height for a contour type mine on 20° slope. Maximum values appear right of the slash.

^c Oil yield of shale is for assumed 30° API gravity oil product with energy value of 132,000 Btu/gal. Yields assume that hydroretorting is a viable process.

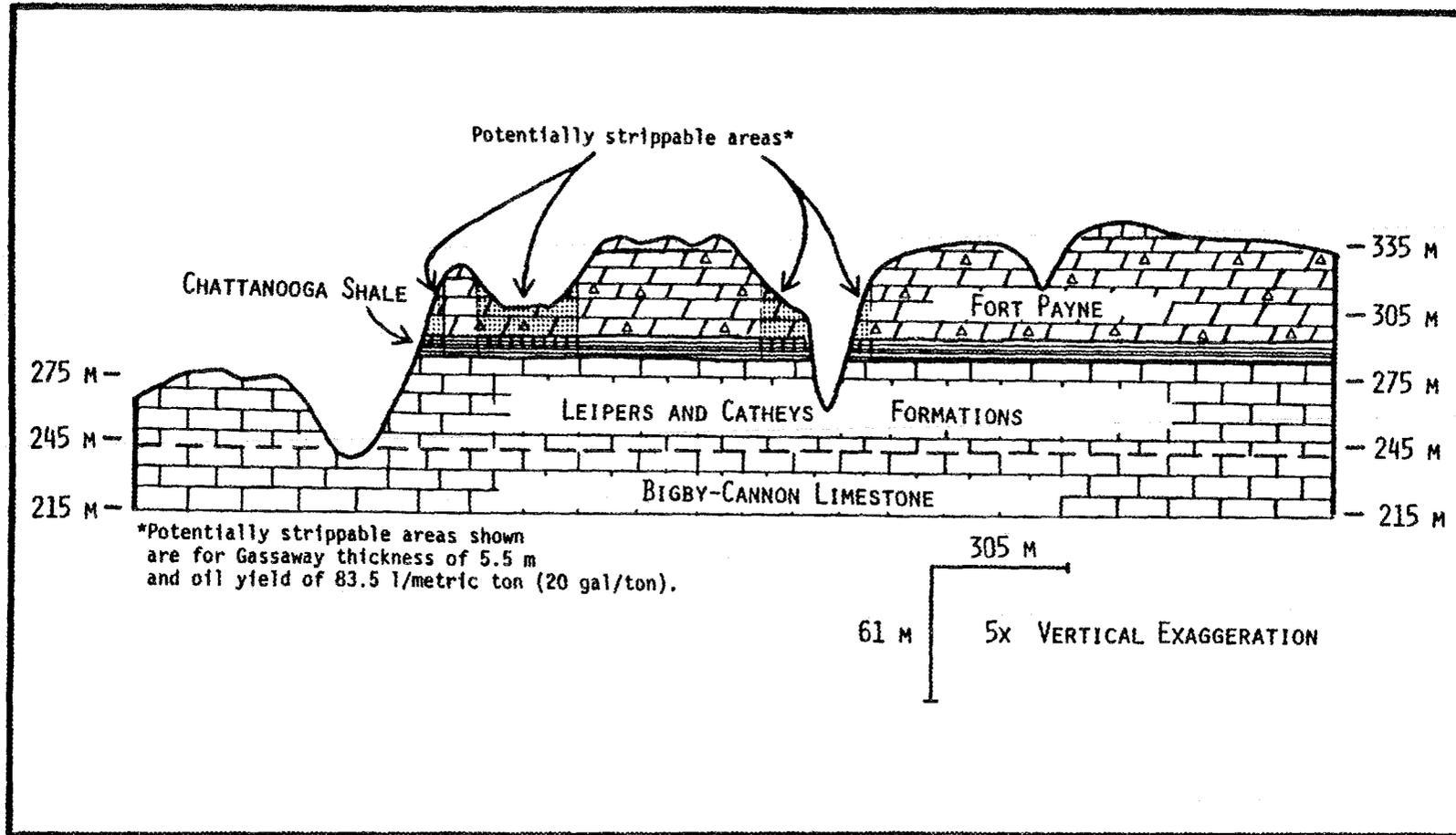


Fig. 4.5. Typical east-west cross section at the Chattanooga shale outcrop.

Table 4.3. Approximate strippable reserves
(metric tons x 1000) per km of outcrop^a

Oil yield, liters/metric ton (gal/ton)	Gassaway thickness, meters				
	3.05	3.66	4.26	4.48	5.48
41.7 (10)	235	315	390	480	575
52.2 (12.5)	265	350	440	540	640
62.3 (15.0)	290	355	485	590	700
73.0 (17.5)	315	415	520	640	805
83.5 (20)	340	445	555	685	815

^a Assuming contour stripping on a 20° slope.

Bench width = $h \times 2.75$

Metric tons/km outcrop = [bench width (m) \times 1000 m/km] \times thickness (m)
 \times 2.3 metric tons/m³ \times 0.9

Actual strippable reserves in any specific locality depend on site specific factors and available information is insufficient to permit calculation of potentially strippable reserves on a county level. Site specific developmental drilling and testing of shale and overburden characteristics and quantity would be required to provide actual strippable reserve estimates.

4.1.6 Legal aspects of mining

The vast majority of land in the Chattanooga Shale Region is owned by the private sector. Only a small percentage is controlled by federal, state, county or local governments. As a result, almost all development along the outcrop must be negotiated through sales and mineral leasing involving individual landowners. Acquiring mineral rights for large underground or surface mines in the Chattanooga Shale Region will entail many repeated contacts and legal contracts to be made with individual landowners. Unlike the western United States, where rural land tracts are usually large and property owners few in number, the rural areas of the Chattanooga Shale Region are broken into numerous small tracts of land. For example, DeKalb County, Tennessee, has 7,977 parcels of rural land owned by 6,500 property holders within its 72,000 ha (278 square miles). Contacting each property owner and negotiating the sale of mineral rights will be time-consuming and expensive.

Shale mining activities on private lands may be regulated by each state in the absence of a federal oil shale mining regulatory framework. Since the Chattanooga Shale Region extends through three states, each state may regulate the development of the industry within its boundaries. Regulations and permitting procedures are unique for each state and are in various stages of formulation and completion at this time.

The Federal Government owns or has jurisdiction over few tracts of land in the Chattanooga Shale Region. Because of this limited ownership, the Department of Interior (DOI), which administers federal lands, has not planned for leasing programs or regulation of eastern oil shale lands as it has western oil shale lands (Hall, 1980). However, three of the prime Chattanooga shale development sites in terms of water and shale resources -- Center Hill Lake, Dale Hallow Lake and Cumberland Lake -- are under federal jurisdiction. The three major water impoundments and their adjacent lands lie along the shale outcrop and are owned and operated by the Corps of Engineers. The Bureau of Land Management (BLM) has jurisdiction over subsurface minerals on Corps of Engineers' land; therefore, BLM would hold responsibility for leasing and developing shale on these lands.

Federal regulation of western oil shale lands is being done through an expanding prototype leasing program. According to DOI, no regulations for shale development are being written at this time, nor are plans being made to develop federally-owned eastern oil shales. As a result, the 47,716 acres of land in Clay, Clinton, and DeKalb Counties in Tennessee and in Cumberland and Russell Counties of Kentucky surrounding Center Hill, Dale Hallow and Cumberland Lakes will not be developed in the foreseeable future.

4.2 Solid Waste Disposal and Reclamation

The design of solid waste disposal systems and reclamation projects is an integral part of mine planning. Unfortunately all too often waste disposal planning occurs as an afterthought, creating unnecessary expense or unaesthetic features on the landscape. This section identifies major considerations in solid waste disposal planning, the magnitude of the problem, and feasible disposal options. The discussion deals with disposal of nonhazardous solid wastes only and excludes consideration of liquid effluents, sludges, slimes, and other processing wastes. At this time the exact nature of the spent shale, the quantity of slimes (fines),

and the characteristics of effluents generated by the processing is unknown. It is assumed that the spent shale will be classified as a nonhazardous waste. It is possible, however, that the waste materials will be classified as hazardous; in that case, the following discussion of disposal options would not be applicable.

4.2.1 Key considerations in solid waste disposal design

The design of a solid waste disposal system and a disturbed land reclamation program for a shale mining and processing operation should be based on a number of key considerations. These considerations can be categorized into three basic groups - processing, environmental, and economic.

The state in which the tailings leave the processing plant is an essential consideration in the development of disposal and reclamation design. The manner of processing determines the characteristics of the spent shale. Characteristics such as grain size and carbon content can affect the volume and compactability of the spent shale as well as its eventual impact on the environment.

The following assumptions have been made concerning the hydroretorting and metals extraction processes and their effects on spent shale.

- The spent shale is classified as a nonhazardous waste.
- The spent shale has been leached for uranium and other metals and contains minimal amounts of these metals.
- The spent shale has been treated with a slurried ground limestone to neutralize the acid from the leaching process and to precipitate soluble elements such as iron and aluminum.
- The spent shale has been roasted; therefore, the organic carbon content of the shale is negligible.

The spent shale will also have the following characteristics as determined by preliminary examination:

- The spent shale is crushed to approximately 0.25 to 0.65 cm (1/10 to 1.4 in.).

- The spent shale weight is 55 to 60% of the original weight of the shale.
- The density of the spent shale is 0.69 g/cc.

The inappropriate and/or unsafe disposal of tailings is potentially one of the greatest environmental hazards of shale development. Environmental systems could be seriously damaged by the improper disposal of wastes. As a result, environmental preservation becomes one of the key considerations in planning a solid waste disposal system. Several regulatory agencies, at state and federal levels, will have jurisdiction over eastern shale development through their environmental protection regulations.

Within the scope of environmental and legal limitations, the options for waste disposal are pragmatically evaluated in terms of economics. While specific methods of disposal may be more aesthetically pleasing or have a smaller impact on the environment, the cost of such disposal systems may be great enough to retard the development of the resource. Costs, both capital and operational, are estimated and discussed for several methods of waste disposal.

4.2.2 Identification of the magnitude of the solid waste disposal problem

Shale, like many other rock materials, increases in volume during mining and processing. This expansion makes complete disposal of the spent shale in the original mining site impossible, thus compounding waste disposal problems. In the case of underground disposal, called backfilling, not only must plans be made to backfill original mine sites, but additional disposal sites must be located and designed. In the case of complete surface disposal of wastes, large suitable areas must be found which have the capacity to store thousands of tons of spent shale per day. When discussing the combination underground and surficial storage of mining wastes, it is imperative to identify the magnitude of the storage disposal problem in terms of the percentage of spent shale that will fit into the mine site and the percentage that is to be stored elsewhere.

Using preliminary weight, volumetric, and compaction data supplied by the Engineering Technology Division of ORNL, it was calculated that a given volume of shale expands about 85% of its original volume during the mining, hydroretorting, roasting, and metals-recovery procedures. Preliminary calculations suggest only 50 to 55% of the spent shale can be backfilled into the original mine site without some form of compaction. The remaining 45 to 50% must be disposed of above ground or in another disposal site such as an abandoned underground mine.

The magnitude of the spent shale disposal problem over a 20 year operational life span of a 100,000 ton (90,910 metric tons) per day processing plant is tremendous. Such a processing plant produces 60,000 tons (54,545 metric tons) per day of spent shale at 43 lb/ft³ (690 kg/m³). Of these 60,000 tons, 50% is expected to return to the mine. The remaining 50%, or 32 acre feet (39,475 m³) per day, must be disposed elsewhere. Over a 20 year operational lifespan, 233,600 acre feet (2.8817 x 10⁸ m³) of spent shale must be disposed on the surface, assuming a 50% mine backfill; with no backfill, 467,200 acre feet (5.7635 x 10⁸ m³) must be disposed. The exact acreage that will be covered with spent shale during the life time of the operation is indeterminable at this time. The terrain surrounding the processing plant will dictate the type of disposal to be used (i.e., land fills will be used in relatively low relief areas while terrain of high relief will require valley fills). Since valley fills have a high volume to surface area ratio, fewer acres of land would be used for waste disposal than if the same amount of waste is disposed in land fills.

Alternative dumping sites such as old coal mines or quarries are often either too distant to make transporting the spent shale economically feasible or are too small to alleviate much of the disposal problem. For example, a quarry that extends over 30 acres (12 hectares) to a depth of 60 ft (18 m) will accept slightly less spent shale than a 100,000 ton (90,910 metric tons) per day processing plant will produce in one month.

The estimate that 50 to 55% of the spent shale will fit into the original mine site may appear low when compared to the Mountain States projection of 70%. Mountain States, however, did not document how this

figure was calculated; the report simply stated: 'It has been assumed that 70% of the tailings produced by the processing plant can be placed underground as backfill material' (Mountain States, 1978). Since Mountain States' backfill design was based on hydraulic transport and hydraulic stowage through a roof hung feeder system, it can be assumed little compaction occurred other than that caused by the weight of the overlying backfill. Given the nature of the spent shale, as determined by the Engineering Technology Division of ORNL, it does not appear feasible to return 70% of the spent shale to the original mine site using the technology described by Mountain States. For the purpose of this study the original estimate of 50 to 55% will be retained for uncompacted shale.

4.2.3 Underground disposal options

Underground disposal of mining wastes has been used extensively in Europe and to a lesser extent in the United States. Backfilling has two advantages: (1) it minimizes the environmental disturbance of the land surface and (2) it allows increased resource recovery. Environmental surface disturbances are reduced by underground waste disposal in that fewer sites exhibit subsidence and less surface area must be dedicated to waste disposal. Smaller amounts of waste material present on the surface also lower the potential of large quantities of sediment and leachates being introduced into surface runoff; however, the leachates are probably introduced into the groundwater instead of the surface runoff. Thus, the total impact is not reduced; only a trade off between introduction of leachates to groundwater rather than surface water occurs. Shale recovery is greater using backfilling (as opposed to nonbackfilling) in that roof supporting pillars can be narrower and designed to fail gradually on the premise that the backfill confines and provides lateral support for the pillars. The increased shale recovery could also extend the life of the mine (Earnest, 1977).

Backfilling a large active mine (with a life expectancy of at least 20 to 30 years) requires a design that allows simultaneous mining and backfilling, or alternating periods of mining and backfilling. If there

is to be no production loss due to backfilling, the stowing of tailings must take place in a part of the mine that is isolated from the mining activities. Mines, therefore, must be designed for backfilling operations, rather than retrofitted, if there is to be no loss of production time. Ideally, mine design must also take into consideration the limitations of the backfilling system in terms of flexibility and mobility. The long open cavities left from chamber and pillar mining activities are more easily filled than the checkerboard cavities left by room and pillar mining. Filling around pillars is difficult when using inflexible semi-immobile systems such as conveyor or pneumatic and hydraulic stowers. Although these stowing systems can be moved, movement is not achieved without considerable effort. Filling a panel mined by room and pillar design with an inflexible stowing system would require too much effort to achieve 100% fill, whereas filling cavities left by chamber and pillar mining requires far less effort.

Evaluation of backfilling options - A variety of methods for backfilling underground coal mines has been used for years. Among the promising ones are pneumatic and hydraulic backfilling and mechanical stowing. Each method is effective under specific circumstances and neither method is best for all mine backfilling conditions and situations.

Analysis of backfilling operations can be divided into two major components - transport and stowage. Transport is the movement of spent shale from the processing plant to the mine site or stowage site. Stowage is the final placement of the spent shale into the previously mined areas. Four major types of transport can be considered - conveyor, mechanical, pneumatic, and hydraulic. Four major types of stowage - conveyor, mechanical, pneumatic, and hydraulic - also can be discussed. Transport and stowage options will be analyzed in the following combinations: hydraulic-hydraulic, pneumatic-pneumatic, conveyor-conveyor, and truck-mechanical. These combinations are generally recognized to be the most feasible.

Pneumatic and hydraulic transport are similar in that the spent shale is conducted from the processing plant to the mine site in a pipeline; only the transport medium differs - air or water. Truck transport entails the movement of solid wastes from the processing plant to the injection

site by dump truck or similar vehicle. Conveyor transport uses a system of conveyor belts for the processing plant to the mine. Each transport system is limited with respect to grade, distance, costs, state of technology, etc.

Pneumatic and hydraulic stowage are accomplished in one of three ways: blind flushing, controlled flushing, and directed flow. In blind flushing the spent shale is injected into the mine through a borehole. The air or water then carries the spent shale to voids, thus filling the mine. This technique is used in filling abandoned mines. Approximately 75% of the mine volume can be filled with blind hydraulic backfilling. In controlled flushing the slurry is injected into a mine through a borehole and directed to areas to be backfilled by pipes connected to the borehole. Generally 300 to 600 ft (90 to 180 m) of horizontal distribution can be obtained for every 100 ft (30 m) of vertical borehole drop in hydraulic controlled flushing (National Academy of Science, 1975); approximately 90% of the mine volume fill can be achieved (Mountain States, 1978). In directed flow the slurry is piped from the borehole to the site to be backfilled where a stower, similar to a giant nozzle, directs the flow of slurry to the exact site. As the backfilling progresses, the stower is moved. To maintain the backfill in its intended position, brattice cloth barriers can be erected. Directed flow backfilling approaches 100% fill. In mechanical stowing the fill is mechanically compacted by self-propelled, tamping-foot drum compactors. The fill rate will depend on the design of the compactor and the amount of clearance it requires between the fill and the roof of the mine. Conveyor stowage is the dumping of spent shale in the mining chamber void by a conveyor system. Once again fill rate is determined by the design of the conveyor system and the clearance it requires. The use of various stowage systems may be limited by mine design, the type of transport system used, capital and operational costs, and the state of stowage technology.

Hydraulic-hydraulic - Hydraulic backfilling, consisting of both hydraulic transport and stowage, has been suggested by Mountain States as the ideal backfilling system for a Chattanooga shale room and pillar mining operation. Mountain States proposes a controlled flushing operation in

in which spent shale would be slurried and piped from the processing plant to a borehole where it would be injected into the mine through a roof-hung feeder system. A network of collection pipes would drain the backfill, and the water would be recirculated through the system. Although not all of the following discussion of hydraulic backfilling directly applies to the proposed Mountain State backfilling plan, the major problem areas of fine generation, water retention in the backfill, creation of fill material unable to provide adequate lateral support to pillars, and mine deterioration still apply.

Hydraulic backfilling presents a set of technological problems that need to be resolved before hydraulic transport and stowage can be considered a viable option for backfilling shale mines. The major problem associated with the use of water for a transport and stowage medium is the production of fines which would retain water in the spent shale, creating an unsuitable water-logged backfill material. The introduction of large quantities of water into the mine could cause mine deterioration and loss of production.

Hydraulic transport of solid wastes is accomplished by slurrying the spent shale, up to 50% by weight, with water. The quantity of water required to transport the spent shale from the plant to the borehole is up to four times greater than the amount of water required to inject the spent shale into the mine, depending upon which injection and stowage option is used. An expensive system for partially dewatering the slurry and recirculating the water to the processing plant prior to injection may be necessary (National Academy of Science, 1975). During hydraulic transport, great quantities of fines are created and carried in suspension due to the readily abradable characteristic of the spent shale. These fines later become a problem in mine drainage and backfill stability.

Even though the total amount of water used in transport may not be necessary for stowage, thousands of gallons of water will be introduced into the mine each day. Although the extent of structural damage caused by water retained and percolating through the fill has not been determined, it is possible that load-bearing structures such as pillars, panel walls and bulkheads could be weakened, deformed, and eventually fail, resulting

in roof collapse and surface subsidence. Water introduced with backfill storage, in all probability, will not remain contained within the backfilled panel or planned drainage system but will seep out of the panel through structural weaknesses (i.e. seams, joints, etc.). Water seepage into the active mining area can cause an increase in water recirculation costs, groundwater contamination, mine degradation (such as the deformation of railroad tracks) and loss of production time. Water returned to the surface from the mine will be sediment laden from backfilling activities. This water will need to be centrifuged or settled and decanted before it can be recycled through the mine. The slimes would be disposed in surface slime ponds.

As the quantity of fines in the slurried spent shale increases, the potential for holding water in the fill also increases. For western spent-oil shale backfill to dewater adequately, the slime portion of the backfill should be limited to 20 to 25%. If the fine content is higher, the fill will be slow to drain. The percolation rate for a high fine content backfill may be as low as 1.4×10^{-3} ft (0.04 cm) per day (Earnest, 1977). Using this percolation rate, it would take 16 ft (5 m) of backfill over 31 years to be dewatered. The increase in fines also tends to increase clogging of drainlines, thus preventing dewatering. Undrained backfill is not able to provide adequate lateral support for the roof supporting pillars, thereby eliminating one of the major advantages of backfilling.

As the fine content of the backfill rises, the density of the fill material may increase due to decreasing pore size among spent shale particles; ostensibly increased fill density improves the support characteristics of the fill materials. With fill density increased beyond the 0.69 g/cc density of the spent shale, more than the expected 55% of the spent shale may fit into the original mine site; the percentage of increase, however, is not known.

The lack of dust is the principal advantage of hydraulic backfilling. The major disadvantages are excessive water consumption, high energy requirement, high capital costs, high operating costs for pumping reclaimed water to the surface, poor support characteristics of the backfill, groundwater contamination, production loss due to seepage, and surface disturbance associated with slime ponds.

Pneumatic-pneumatic - Pneumatic backfilling, consisting of both pneumatic transport and stowage, has been used mostly in Europe in long-wall coal-mining operations. Shale to be pneumatically transported is fed into abrasion-resistant pipes and blown to the stowage site.

As is the case with hydraulic backfilling, many technological problems must be resolved before pneumatic transport can be used to backfill shale mines. Dust and the creation of fines are the greatest problems associated with pneumatic backfilling. Pneumatic transport creates a large quantity of fines as pieces of spent shale collide with one another and the pipe; the fines are then released as dust during stowage. Mine ventilation systems must be designed to prevent dust from entering the area of the mine which is actively being worked. The problem of fines is not as great in pneumatic backfilling as it is in hydraulic backfilling because the settling velocity of fines in the air is greater than in water. If the backfill, however, becomes saturated by groundwater, it will be difficult to drain for the same reason that hydraulic backfill is difficult and slow to drain; in addition, there will be no network of drain pipes to dispose of excess water. Once the backfill is saturated it will not lend sufficient lateral support to load-bearing pillars.

Pneumatic stowing may increase fill density up to 14% due to compaction caused by fill depth and high velocity impact according to Earnest, 1977. It is doubtful, however, that fill density of spent Chattanooga shale will increase greatly due to compaction under its own weight. Assuming the average depth of backfill will be 16 ft (5 m), and given dry spent shale weights of 43 lb/ft³ (690 kg/m³), the pressure on the bottom of the fill pile will be approximately 5 lbs/in.² (3360 kg/m²). According to ORNL compaction studies, 5 pounds per square inch (3360 kg/m²) of pressure will not be sufficient to perceptibly increase fill density. If fill density is greater for pneumatically transported fill than spent shale, it is probably due to the generation of fines and general degradation of the spent shale particles during transport.

With a moveable stower and chamber and pillar mining, complete backfilling is possible.

Pneumatic stowing can be easily linked to other haulage systems. For example, if conveyor or truck transport is used, the spent shale can be fed into a pneumatic stower at the backfill site. The combination of conveyor or truck transport and pneumatic stowage probably will not create the great quantity of fines that pneumatic transport combined with pneumatic stowage creates.

The principal advantages of using pneumatic backfilling are that little water is introduced into the mine and that the stowing system can accommodate several forms of transport. Disadvantages are abrasion to pipelines, dust generation, poor support characteristics of saturated backfill, and high energy requirements.

The capital cost of pneumatic transport depends on the number of linear feet and turns required between the processing plant and the stowage site. The energy required to transport shale around a corner is equivalent to the frictional loss of energy in transporting material 200 ft horizontally (National Academy of Science, 1975). As mining advances, the number of linear feet of pipe must be increased. The addition of pipe, and perhaps corners, would require additional blowers to resuspend the spent shale, thus increasing capital costs and energy requirements. In general, capital and operating costs, as well as energy requirements of pneumatic backfill, are high.

Conveyor-conveyor - Waste disposal by conveyor transport and conveyor stowage is accomplished by a main system of conveyors used to transfer the spent shale to the mine. In the mine, splitters transfer the spent shale to a number of cross belts which carry the spent shale to stowage sites. Extendable belts are then used for actual chamber filling. Conveyor transport is generally used in terrain considered too steep for trucks, but not over 20°.

Conveyor stowage is more feasible when associated with chamber and pillar mining than room and pillar mining. Given the inflexibility inherent in conveyor use, it would require continual extension and addition of crosslines to fill around the many corners of a room and pillar mining system. Conveyor stowage cannot backfill a chamber to capacity. The space left at the top can be left vacant or can be filled by another

stowage technique such as pneumatic stowing. (The backfill transported and stowed by conveyor systems should be more similar to the spent shale as it exits the processing plant than the backfill that is generated by pneumatic and hydraulic systems.) The density and number of fines should increase minimally during conveyor transport or stowage. Some dust will be generated at transfer points, but it should be controllable with water or proper ventilation.

Principal advantages of conveyor backfilling are low operational cost, low manpower and energy requirements, little introduction of water into the mine, and minimal dust and fine generation. Inflexibility of routing and high capital costs are the major disadvantages.

Truck-mechanical - Solid waste disposal by truck transport and mechanical stowage is accomplished by using large off-road hauling vehicles and self-propelled, tamping-foot drum compactors. Off-road trucks, that are best used on low-grade short distance hauls, would carry spent shale from the plant to the stowage site in the mine where they would discharge their load and return to the surface. The mine design would have several modifications for vehicle traffic. The passageways and entries would be widened and ventilation (for fumes and dust) increased.

The backfill material will experience only minimal degradation from transport and compaction. The ultimate density of the fill material will be dependent on the compactability characteristics of the spent shale and the amount of compactive force applied to it (see Table 4.4). Increased fill density may increase lateral support to load-bearing structures and decrease fill permeability; however, testing on spent Chattanooga shale is necessary to confirm this.

The advantages of truck-mechanical backfilling include flexibility in routing, increased disposal of wastes in underground sites and increased support characteristics of fill material. The disadvantages of this method are high manpower and equipment requirements, high energy consumption, and increased ventilating requirements.

Concluding remarks on backfilling - Backfilling of shale mines, by whatever option, is strictly in the planning and theoretical phase; no shale mine has actually been backfilled. Ideally if the spent shale is to

Table 4.4. Preliminary compaction data

Confining pressure	Unit weight	Increase in density
[psi (kg/cm ²)]	grams/cc	(%)
As received	0.69	
500 (35.2)	0.82	18
1,000 (70.45)	1.00	45
2,000 (140.9)	1.12	62
5,000 (352.3)	1.27	84
12,000 (1409.0)	1.38	100

be placed into the original mine void, compaction will be necessary for maximum disposal, to prevent the formation of leachates by water percolating through the fill material, and to minimize surface subsidence (Cooke, 1974). Current backfilling technology, as described in the previous sections, cannot accomplish all of the objectives, but this should not be viewed as a serious constraint to the use of underground disposal of spent shale. Compaction techniques and machinery could be developed with the present level of sophistication in mining technology. In addition to technology development, the economics and possible environmental impacts need to be analyzed and proven acceptable before underground disposal of solid wastes is considered a viable disposal alternative.

4.2.4 Surface disposal

Surface disposal of solid wastes will be the greatest visible expression of the development of the shale resource. Some surface disposal is inevitable for several reasons. First, not all the spent shale will fit into the original mine site; second, surface disposal is by far the least expensive disposal option; and finally, no laws or regulations exist which make the underground disposal of waste mandatory.

Surface disposal is usually accomplished by a system of conveyor belt transport and stowing, transport by conveyor and truck, and final stowage by grading or slurring the spent shale through a pipeline. The choice of transport system is dependent on cost influencing factors such as grade and distance from the processing plant to the disposal site.

One of the major factors affecting surface disposal will be the availability of sufficient suitable acreage within the proximity of the processing plant. The actual form and manner of construction of the landfill or impoundment will depend on the topography and the hydrology of the area. Other factors influencing the design of the disposal site will include the amount of waste and its characteristics of shearing, compactability, permeability, etc., which have not been determined at this time. The spent shale should not be appreciably degraded by conveyor, truck, or mechanical transport. Dust could be generated at transfer points but

should be controllable with the water. The spent shale, however, if transported as a slurry will degrade and generate large quantities of fines, making dewatering difficult or impossible.

The recent trend of disposing of huge quantities of mining waste is to impound the material behind man-made dikes or in valleys which have been dammed for waste disposal purposes (Hass, 1976). The other major disposal option currently used is the landfill. The two major design considerations in disposal impoundments and landfills are safety and environment. Impoundments must be designed to minimize potential failure from liquefaction, sliding, slumping, piping, etc., brought on by saturation caused by improper drainage or layering of materials (Hass, 1976). An adequate drainage system, to accommodate normal surface runoff and water introduced through the disposal process, must be provided during active filling and later as the retention basin becomes inactive. If adequate drainage is not provided the dike or dam can fail or the tailing can overflow the impoundment. In either case, tailings flow down the valley, covering the landscape, causing damage to crop or forest lands, and endangering lives and settlements.

Surface disposal sites of spent shale must be protected from erosion during periods of active disposal and after suspension of disposal activities. Surface runoff can erode the fill material and transport sediment out of the retention basin, which will affect downstream water quality. Wind erosion presents a relatively minor problem that exists only during dry periods. To decrease the erosion caused by surface run-off and wind, the impoundment structure and retention basin may be vegetated or treated with chemicals to create a crust on the surface.

Reclamation - The method used to vegetate the waste will depend on the characteristics of the spent shale. If the shale has been leached for metals during processing, it probably will not have sufficient mineral content to support a vegetation program. The spent shale will probably have to be covered with topsoil, mulched, and fertilized before the site can be planted. The quantity of topsoil necessary to cover disposal sites will be exceedingly large, and its acquisition may necessitate the use of several options (e.g., stripping topsoil from the site before dumping the

spent shale and storing it, stripping topsoil from other sites, or using dredged material from reservoirs or river channels).

Low capital and operational costs, minimal generation of fines, and low energy requirements are the advantages of surface disposal. The main disadvantages are aesthetic and environmental degradation including sedimentation of run-off, alteration of land use, disruption of hydrology, alteration of species composition, etc. Specific environmental impacts caused by surface disposal will be discussed later in this report.

For summary of the advantages and disadvantages of the previously discussed disposal options, see Table 4.5.

4.2.5 Alternative uses and disposal sites

The magnitude and expense of the waste disposal problem will be so great that any minor alternative use of the spent shale would not significantly diminish the underground and surficial disposal problem and accompanying cost. Although the exact characteristics and utility of the spent shale have not been determined, it is assumed that some shale will be used for construction fill. Intermittent need for constructing fill will be generated by the growth of the industry and surrounding communities as the shale resource is developed; however, the local need will be sporadic and cannot be considered a dependable option for the consistent disposal of major amounts of spent shale.

4.2.6 Disposal of fines

The quantity of fines generated by crushing and the hydroretort and metal extraction processes and waste disposal is not known. As a result, the magnitude of the problem and the approach necessary to resolve it cannot be identified. Slime pond or impoundment dams with retention basins are generally used to settle out fine sediments from the water used in shale processing or transport of spent shale. After the sediment has settled naturally with time, the water is decanted and recycled through the

Table 4.5. Summary of qualitative comparisons of disposal options

Characteristics	Method				
	Hydraulic-hydraulic	Pneumatic-pneumatic	Conveyor-conveyor	Truck mechanical	Surface
Percent fill achievable	75-100	75-100	--	--	NA
Problem areas					
Fine generation	■	■	▼	▼	▼
Water retention capability of backfill	■	■	●	●	●
Support and load-bearing capacity	●	●	▲	■	■
Mine deterioration	■	▲	▼	▼	NA
Loss of production due to backfilling	▲	●	▼	▼	NA
Ground H ₂ O contamination	■	■	▼	▼	▲
Dust	▼	■	●	▲	●
Surface disturbance	●	●	●	▼	■
Surface water contamination	▼	▼	▼	▼	■
Increased mine ventilation	▼	■	▼	■	NA
Wind erosion	▼	▼	▼	▼	●
Alteration of land use	▼	▼	▼	▼	■
Surface hydrology disruption	●	●	●	▼	■
Ability to link stowage option with other transport options	▼	▲	●	●	NA
Flexibility of routing	▲	▲	●	■	■
Aesthetic alteration of surface	●	●	●	●	■
Costs					
Capital	■	■	●	▲	●
Operation	■	■	▲	▲	●
Manpower	■	■	●	■	●
Energy consumption	■	■	●	■	●
Water consumption	■	▼	●	●	●

LEGEND:

- NA - not applicable
- - high
- ▲ - medium
- - low
- ▼ - minimal
- - data not available

mine and plant or returned to surface flow. Slime ponds in the Chattanooga Shale Region must be designed large enough to accept heavy precipitation without overflowing and carrying suspended sediment out of the settling ponds. Slime ponds once filled or after project termination must be buried and revegetated so the fines will not be transported out of the impoundment by wind or water.

Until the exact quantity of fines generated in mining, crushing, hydroretorting, waste disposal, etc., is known, disposal options cannot be planned and their costs cannot be determined.

4.2.7 Legal considerations of solid waste disposal and reclamation

The regulation of the disposal of mining wastes, processed mineral wastes and processing effluents will be one of the major considerations in the development of the eastern oil shale industry. Many governmental agencies directly or indirectly regulate the disposal of these wastes on both the federal and state level. Overlapping regulations and nonregulated activities make the legal status of solid waste disposal and reclamation of mined oil shale lands uncertain.

Federal -- At the federal level, waste disposal of spent shale comes under the jurisdiction of several agencies (i.e., Department of Interior and Environmental Protection Agency). The disposal of spent shale is regulated by the Department of Interior through the prototype leasing program which has been implemented for western shales only. The Environmental Protection Agency (EPA) has several offices which regulate solid waste disposal or the effects of solid waste disposal. The EPA Office of Solid Waste administers the Resource Conservation and Recovery Act (RCRA). Originally RCRA was designed to regulate mining wastes but was amended by HR3994 to exempt certain mining and mineral processing wastes from EPA regulation until such time that studies determine whether these materials present health or environmental hazards. EPA is in the process of collecting data on spent eastern oil shales. This project, however, has been given low priority because EPA is more concerned with studying and developing regulations for developed mining industries (e.g., the phosphate industry) (Garve, 1981).

The EPA Office of Drinking Water - Underground Injection Control Program regulates the subsurface placement of fluids, including mining waste streams, in order to protect the quality of drinking water aquifers. Some, though not all, methods of backfilling mines are regulated by the Underground Injection Control Program. If mines are backfilled through wells by hydraulic or pneumatic methods, they fall under EPA Underground Injection Control regulation; however, backfilling accomplished by mechanical means (e.g., truck or conveyor) would not be covered by these regulations (Belk, 1981). These regulations will be implemented through state-run programs or the EPA if states default. State programs should be in effect by April 1981 or at the termination of the 280-day extension period past the April deadline (Anzzolin, 1981).

EPA also has jurisdiction over solid waste disposal through the Federal Water Pollution Control Act amended by the Clean Water Act, 1977, and the Safe Drinking Water Control Act, 1974. Provisions for determination and regulation of maximum allowable contamination standards for surface and groundwater are made through these acts.

Reclamation of surface disturbances caused by shale mining, both surface and deep, is not regulated by a federal agency at this time. The Surface Mining Control and Reclamation Act regulates only reclamation of surface disturbances associated with coal mining from surface and deep mines. However, the regulatory and enforcement authority of the Federal Office of Surface Mining is superseded or assumed by the states as they start individual programs. The state programs often expand their regulatory authority to cover minerals and materials other than coal.

Alabama - In Alabama the Department of Industrial Relations, Division of Land Reclamation regulates the surface mining of 'clay, sand, gravel, ores and other minerals....' The division also regulates reclamation of surface disturbances caused by the surface mining of the materials. Although specific regulations are not written for governing oil shale, general regulations would apply because shale is considered an 'other mineral' (Weller, 1981). Deep mining is also regulated by the Land Reclamation Division as is the reclamation of surficial expression of deep mining. No regulation for the backfilling of mines in Alabama exists at this time.

Surficial solid waste disposal of process mineral wastes is regulated by the Solid Waste and Vector Control Division of the Public Health Department. Any large solid waste impoundment such as a valley fill will also be monitored by the Water Improvement Commission.

Kentucky - The General Assembly of the State of Kentucky placed a moratorium on the mining of shale in the spring of 1980. Except for a few demonstration projects, shale mining has been suspended. Regulations are being written by the Kentucky Bureau of Natural Resources pertaining specifically to shale mining, waste disposal and reclamation; these regulations are to be completed by June 1981. The enforcing agency for shale mining and reclamation will probably be the Kentucky Surface Mining Reclamation and Enforcement Bureau. Although the specific agency for the regulation of the disposal of mining wastes and processed mineral wastes has not been decided at this time, it will be housed in the Natural Resources and Environmental Protection Department.

Tennessee - In Tennessee the Department of Conservation's Division of Strip Mining and Reclamation has jurisdiction over surface mining and its reclamation including shale mining and reclamation. The division also regulates the reclamation of the surface effects of deep mining; at this time, however, regulation is restricted to coal only with no provision for other minerals. The Division of Strip Mining and Reclamation is in the process of writing regulations for the new strip mining law passed by the Tennessee legislature on May 2, 1980. The regulations should be submitted for public review and comment by June of 1981.

The Department of Labor, Mining Division, has jurisdiction over deep mining in the State of Tennessee. At the time no regulations concerning backfilling of mines nor underground waste disposal existed in the State of Tennessee.

Surface disposal of processed mineral wastes will be regulated by the Division of Solid Waste of the Public Health Department.

4.2.8 Hazardous waste

The preceding discussion was limited to solid wastes classified as 'nonhazardous.' No discussion was directed toward the possibility of the waste being declared 'hazardous' and its subsequent disposal, nor was discussion directed toward the storage and disposal of unprocessed shale and processing effluents.

At this time disposal of mining tailings and certain processed mineral wastes have been removed from EPA jurisdiction and cannot be classified a hazardous waste subject to its regulation. Therefore, it has been assumed, for the economic analysis, that the waste is considered nonhazardous and will not incur additional costs associated with extensive disposal site preparation and continual monitoring. If, at some time in the future, the raw or spent shale is deemed a hazardous waste, new disposal techniques must be used and much greater expense will be incurred. Mine backfilling will probably not be allowed because the mines may be overlain by limestone aquifers. Water from the aquifers could percolate through the backfill forming a leachate. Most likely the waste would be disposed of in a secure landfill requiring an impermeable clay-lined reservoir and long-term maintenance and monitoring to prevent contamination of ground water. Ostensibly, the costs associated with finding adequate disposal sites (in terms of size and satisfying regulations), site preparation and site monitoring would raise total costs significantly, perhaps to the point of creating a need for economic reassessment.

The EPA is currently considering that mining wastes having a concentration of ^{226}Ra in excess of 5 pCi/g might be subject to regulation as 'hazardous waste' and possibly require provisions such as covering them with an impermeable cap to minimize the radon gas release. At this time no measurement of the radioactivity of the hydroretorted or hydroretorted and leached shales has been made. However, it may be calculated that the raw shale with a uranium concentration of 60 ppm has a ^{226}Ra concentration of 20 pCi/g and that spent shale with 75% radium removal by leaching would have a ^{226}Ra concentration of 5 pCi/g.

Of the three types of shale - raw, hydroretorted, and hydroretorted and leached - raw shale is assumed to have the greatest potential for being environmentally dangerous. From it many trace elements can be leached. Exposure of raw shale to weathering and leaching can foreseeably happen in two areas: during stockpiling of raw shale before processing and in the disposal of raw shale fines. During these exposed periods contaminants can be leached from the raw shale and transported through surface runoff and groundwater. No provision for the protection of raw shale from rain during stockpiling was made in the Mountain States report, nor was provision made for the pelletization and subsequent hydroretort processing of the fines - only the disposal of the raw fines was mentioned. If raw shale stockpiled or disposed on the surface is regulated in the future, provisions must be made to protect it from being leached or to capture runoff water.

Hazardous wastes other than spent shales will be generated by the oil and metals extraction processes. These wastes, which include organic and trace-metal-bearing sludges, must be disposed in accordance with the EPA regulations as mandated by the Resource Conservation and Recovery Act.

4.2.9 Summary

One specific type of solid waste disposal cannot be identified as being superior to other forms of disposal. At this time not enough is known about the nature of the spent shale to recommend a specific waste disposal system. In all probability two or more types of disposal will be combined, especially if the life of the mine is extended beyond 20 years and the total amount of tailings becomes mountainous. The major influencing factor in determining waste disposal probably will be government regulations. The design of waste disposal systems will be determined by criteria set forth in future EPA regulations, or, in the absence of regulation, the least expensive form of disposal will be used.

4.2.10 Uncertainties

Actual testing of hydroretorted and leached spent shale, to determine its geotechnical engineering properties and chemical composition, must be performed before more conclusive and concrete discussions of waste disposal options can be undertaken. Tests performed on representative samples from demonstration scale-processing facilities would provide the best measure of spent shale population. Once the geotechnical and chemical properties of the spent shale are known, safe, efficient, and environmentally sound disposal systems can be designed. Until that time important design considerations (e.g., the density and lateral support capabilities of backfilled shale and the permeability and water retention characteristics of mechanically compacted shale) must be estimated or dealt with in general terms. The actual weaknesses of existing waste disposal systems, which are thought to be applicable for spent shale, cannot be identified until the measurements are made. Examples of geotechnical engineering property tests which need to be run are compaction, permeability, permeability under compaction, triaxial strength, shearing strength, and abrasion resistance.

Final determination of the chemical content of hydroretorted and leached shale is also necessary. It has been assumed that the spent shale would be considered a nonhazardous waste; however, verification of this premise is necessary. The knowledge of its exact chemical content is also necessary for determining the nature of the fill material. The carbon, aluminum, and silicate contents can affect the cementation properties of the fill material. The cementation characteristics of the fill affect the load-bearing capacity. Vegetation programs are also affected by chemical content. It may be necessary to add nutrients and organic material to the spent shale before seeding and planting programs are initiated.

The quantity of fines produced by crushing, hylorting, roasting, and leaching of Chattanooga shale is not known. To design adequately large settling ponds and disposal systems, the quantity of fines generated needs to be more accurately determined.

Once the above tests are performed, a more accurate prediction of the viability and economics of specific waste disposal programs can be made.

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5. RECOVERY PROCESS ASSESSMENT

The purpose of this chapter is to assess the literature and to develop reference designs for the technical and economic evaluation of the recovery of hydrocarbons and minerals from Chattanooga shale. A number of processes have been developed and demonstrated at near-commercial scale for the recovery of oil from western oil shale (IGT Symposium Papers 1980). They are considered ready for commercialization. A hydrocarbon recovery process for Chattanooga shale has not been fully developed. However, for study purposes, the reference design of a potentially suitable hydroretorting process was conceived on the basis of laboratory-scale experiments performed at ORNL and flow tests that were performed in a bench-scale unit and a process development unit at IGT (IGT 1980a and IGT 1980b). The reference design of a process for minerals recovery from Chattanooga shale was developed on the basis of leaching experiments at ORNL (Silverman 1981) and earlier studies at Columbia University (1955). Both hydrocarbon and minerals recovery designs are developed only to a degree of detail suitable for technical and economic evaluation.

Of the processes that have been developed for oil recovery from western shale, the Paraho (Pforzheimer 1980) and Union (Ohondt 1980, Hopkins 1980) processes are based on the pyrolysis of shale at essentially atmospheric pressure utilizing spent shale combustion gases as the source of heat. Each process has been demonstrated at the 1500 ton/d scale, producing close to the Fischer assay amount of oil. The Superior process (Boyd 1980) has similarly been operated at a 250 ton/d scale. The Brazilian Petrosix process, also similar, has been operated at 2000 tons/d.

In each of these processes, shale is heated with gases through a preheating zone and then in a retorting zone to a maximum temperature of about 900 to 950°F (480 to 510°C). With western shale, yields of oil are about 0.5 to 0.7 bbl/ton of shale. About 15 to 25% of the carbon is left in the hot ash; this carbon is burned to provide energy for the process. The hot ash is used to heat gas streams used in the process or to generate steam.

The Lurgi-Ruhrgas and Tosco processes are based on the pyrolysis of shale at atmospheric pressure utilizing recirculating hot solids as the source of heat. In the former, spent shale is combusted and mixed with the raw shale. In the latter, ceramic balls are heated through shale combustion and combustion of retort gas and recycled to heat the retort. The former process has been demonstrated on African shale at 400 tons/d and the latter on western shale at 1000 tons/d.

IGT is developing the Hytort process for eastern shale (Feldkirchner 1980) which seems to have the potential for gross recovery of 60 to 80% of the carbon in eastern shale (vs about 35% recovered in a simple indirectly heated retort). The Hytort process, in which shale is retorted with hydrogen at about 500 psi (3.4 MPa), produces a high-quality hydrotreated crude oil. However, the process suffers from a number of disadvantages:

- a. The oil yield achieved in IGT's 1 ton/h process development unit thus far has been well below the 2 to 2.5 x Fischer assay claimed on the basis of lab-scale tests.
- b. Most or all of the hydrocarbon gas product is reformed and used internally for hydrogen production.
- c. The process is inherently more costly and complex than other retorting schemes because of the high pressure, a large recirculating hydrogen stream (requiring pumping and continuous cleaning), and the requirement for oxygen to burn hydrogen for heating within the retort.
- d. About 30% of the energy is discarded in the spent shale and the fines.

The Buffalo Trace Area Development District (BTADD) — with Davy McKee as prime contractor, the Cleveland Cliffs Iron Company as mining subcontractor, and the University of Kentucky Institute for Mining and Minerals Research (IMMR) as resource assessment subcontractor — has completed a nine-month conceptual design study of a project for recovery of oil from an outcrop of oil shale in Fleming County, Kentucky (Davy McKee 1981). A reference plant site was selected in which shale could be stripped with an overburden ratio of less than 2:1, and conceptual designs were made of plants for retorting 30,000 tons/d of shale by the Paraho and Hytort processes. Although neither process has yet been tested in the selected

plant configurations, it was estimated that both would produce about 10,000 bbl/d of oil (~115% of the Fischer assay) with SNG and electricity as significant by-products of the Paraho process and sulfur and ammonia as incidental by-products of the Hytort process.

The modified Paraho process assumed a two zone atmospheric pressure reactor. In the upper zone fresh shale is retorted with an externally heated stream of recirculating reducing gas. In the lower zone the residual carbon is burned with air to heat the recirculating gas and boil water for power generation (with limestone scrubbing for flue gas desulfurization). This process configuration utilizes virtually all of the organic carbon in the shale and is estimated to permit recovery of 44% of the input energy as oil, 15% as high Btu gas, and 8% as excess electrical power.

The 'Hytort' process analysis was of limited scope because the experimental results to date essentially only involve the results of contacting shale with hydrogen and do not provide data for an overall, energy-efficient process. The configuration chosen for the analysis assumed a two stage, 30-ft-tall retort in which downflowing shale is retorted with relatively pure hydrogen at 550 psia. The hydrogen is produced from the overhead product stream by a series of unit operations that involve (1) scrubbing for oil recovery, (2) acid gas removal, (3) cryogenic separation, and (4) steam reforming. This hydrogen stream enters the bottom of the retort to cool the spent shale and is partially burned (with oxygen from an air liquefaction plant) in the middle section to heat the shale to the 1200°F retorting temperature. In this design 44% of the organic carbon content of the shale is converted to product oil, all of the gases (representing 28% of the carbon) are consumed internally, and the remaining 28% of the carbon is discharged as spent shale.

This version of the Hytort process did not compare favorably with the low pressure Paraho process since it produces only the same quantity of oil product while discarding a large fraction of the carbon and consuming 575 tons/d of oxygen and 45 MW of electric power. The capital investment required for the high pressure retorts, water pressurized feed and discharge lock hoppers, the gas recirculation system, and the oxygen plant

for the Hytort design were considerably higher than that required for the low pressure retorts, simpler gas recirculation system, power plant, and limestone scrubbing system for the Paraho design.

On the basis of the Paraho design, Davy McKee concluded that oil recovery from eastern oil shale appears to be commercially feasible. They estimate that crude shale oil could be produced at a cost of \$40/bbl on the basis of: (1) 100% equity and 12% rate of return, which gave annual charges on capital of \$96.7 million/year (\$648 million initial capital plus \$126 million invested for additional mine development in years 8, 12, 13, and 18), (2) annual operating and maintenance expenses of \$63.1 million/year, (3) annual revenues from shale oil of \$107.3 million/year (8132 bbl/d of oil at \$40/bbl from 30,000 tons/d of shale), and (4) annual revenues from by-products of \$52.5 million/year (2282 bbl/d of light oil at \$25/bbl, 14,500 scfm of high Btu gas at \$3/million Btu, and 48.3 MW of electricity at \$0.0275/kWh).

Although a process that combines atmospheric pressure retorting with combustion of spent shale (or, alternatively, a hydrogasification process) might be more economical for the recovery of hydrocarbons from Chattanooga shale, the Hytort process has been used to develop the reference design for this study. Directly applicable data are available from the small scale hydroretorting of Chattanooga shale as well as from experiments in which spent hydroretorted shale was leached with sulfuric and hydrochloric acids. The available data indicate that high minerals recovery is possible by acid leaching of spent shale after it has been hydroretorted and roasted in air at about 900°F (500°C) and that there would be significantly less mineral recovery from acid leaching of spent shale that had been combusted at a temperature of 1400 to 1600°F (760 to 870°C). Although about 30% of the hydrocarbon energy of the shale remains after hydroretorting, most of this energy can be utilized in the roasting process prior to leaching for minerals recovery.

The following sections will review the available experimental data and develop the reference designs for the hydrocarbon and minerals recovery processes.

5.1 Hydrocarbon Recovery

At the time of this writing no engineering scale data are available for the hydroretorting of Chattanooga shale. Plans are being made at IGT for a process development unit experiment with Chattanooga shale, but the shale that is available in sufficient quantity for this experiment has relatively low carbon content (only about 10%) and probably is not representative of the richer deposits (14 to 16% carbon) that would be exploited in initial commercial operations. In the absence of engineering scale data, the reference design of the hydroretorting process for hydrocarbon recovery from Chattanooga shale has been constructed on the basis of ORNL batch heatup tests with Chattanooga shale and IGT bench-scale and process development runs with New Albany oil shale, a shale that is similar to high-grade Chattanooga shale.

Measured properties of batches of Chattanooga shale and New Albany shale that were used in the experimental work as well as a synthesized design basis for Chattanooga shale are presented in Table 5.1. As compared with the New Albany shale used in the experiments, the Chattanooga shale appears to have slightly higher concentrations of carbon and hydrogen, a relatively higher proportion of organic carbon, approximately the same concentrations of sulfur and nitrogen, and about one-third less organic oxygen. (The experimental measurement that indicates a much lower content of organic oxygen in Chattanooga shale is believed to be in error on the basis of mass balances obtained in the ORNL experiments.) The significance of the differences in the two shales, particularly the higher organic carbon and the lower organic oxygen content, is that the Chattanooga shale should have higher hydrocarbon energy content, higher oil yields, and less water production in hydroretorting. These trends have been confirmed in the experiments.

A summary of the reference experiments with Chattanooga and New Albany shale, along with a synthesized design basis, is presented in Table 5.2. The experimental procedures and the derived data will be discussed in the following sections.

Table 5.i. Properties of shale used for experimental studies and design basis

Type of shale sample designation experiment no.	Chattanooga												Chattanooga design basis	
	US 70 ^{a,c}			3178 ^{b,c}			3178 ^{b,d}		New Albany				Raw shale	Retort residue
	Raw shale	ORNL-2	ORNL-4	Raw shale	ORNL-3	ORNL-6	Raw shale	Retort residue	79 BSU-2 ^e		80 PDU-2 ^e			
		Test residue	Test residue		Test residue	Test residue			Test residue	Raw shale	Retort residue	Raw shale	Retort residue	
Ultimate Analysis, wt. %														
Organic carbon							14.14		13.06	4.68	14.17	4.22	14.05	5.33
Mineral carbon							0.02		1.05	0.48	0.27	0.08	0.02	0.00
Total carbon	16.38	12.14	7.65	14.08	11.09	5.85	14.16	4.40	14.11	5.16	14.44	4.30	14.05	5.33
Hydrogen	1.72	0.58	0.51	1.79	0.66	0.63	1.57	0.22	1.51	0.28	1.57	0.21	1.57	0.24
Nitrogen							0.50 ^f		0.46	0.16	0.54	0.13	0.50	0.16
Oxygen (high temp. water)							0.72 ^f		4.45	0.00	4.03	0.71	2.80	0.52
Sulfur	6.97	3.31	3.85	5.06	1.75	2.69	4.82		4.94	3.21	5.19	3.56	4.92	2.65
Ash	73.7	84.33	89.8	74.97	85.8	92.2	78.23		74.53	91.98	77.22	93.59	74.81	92.10
Moisture	0.55	0.02	0.08	1.25	0.08	0.02	1.00	0.1	1.5	0.10	1.90	0.0	1.25	0.00
Total	99.32	100.38	101.89	97.15	99.4	101.39	101.00	4.72	101.50	100.89	104.89	102.55	100.00	100.00
Metal Analysis, ppm														
Aluminum				60,000									60,000	
Columbium				20									20	
Cobalt				60									60	
Chromium				100									100	
Iron				60,000									60,000	
Manganese				350									350	
Molybdenum				200									200	
Nickel				200									200	
Vanadium				300									300	
Uranium	79	80	85	75	75	67							65	
Higher Heating Value, Btu/lb								2813		3550	1019		2813	1015
Bulk Density, lb/ft ³								71.7		74.5	65.6	74.5	71.1	71.7
Helium Density, g/cm ³								2.25		2.31	2.66	2.27	2.72	2.25

^aWeathered shale taken from road cut in Smith County, 30 miles west of Cookeville, TN.

^bSample of Gassaway member provided by IGT. Feldkirchner, H. L. (IGT) letter to J. S. Watson (ORNL), May 13, 1980.

^cORNL analysis.

^dIGT analysis.

^eIGT data reported in DOE/ET/14102-1 and DOE/ET/14102-2.

^fProbable error. Organic oxygen is probably about 3% on the basis of mass balances for the ORNL experiments.

Table 3.2. Summary of experimental results of retort tests with Chattanooga and New Albany shale and assumed design basis for Chattanooga shale

Shale	Chattanooga ^a ORNL-2	Chattanooga ^a ORNL-3	Chattanooga ^a ORNL-4	Chattanooga ^a ORNL-6	New Albany ^b 79 BBU-2	New Albany ^c 80 PDU-2	New Albany ^d 80 PDU-2	Chattanooga ^e 3178
Atmosphere	Argon	Argon	H ₂	H ₂	H ₂	95% H ₂	95% H ₂	95% H ₂
Pressure, psig	0	0	500	500	327	406	406	500
Max. shale temp. °F	1220	1220	1220	1220	1234	1355	1355	1300
<u>Net product, lbs/lb raw shale</u>								
Spent shale	0.8730	0.8796	0.8224	0.8279	0.799	0.8090	0.8090	0.8212
Oil	0.0471 ^f	0.0512 ^f	0.0822 ^f	0.0954 ^f	0.0606	0.0642	0.0642 ^f	0.0939 ^f
H ₂						0.0019	0.0019	0.0019
CO	0.0014	0.0021	0.0075	0.0030	0.0150	(0.014)	(0.0154)	(0.0039)
CO ₂	0.0022	0.0060	0.0002	0.0003	0.0066	0.0037	0.0037	0.0046
H ₂	0.0012	0.0010	(0.0063)	(0.0062)	(0.0061)	(0.0064)	(0.0064)	(0.0064)
CH ₄	0.0064	0.0058	0.0232	0.0109	0.0163	0.0234	0.0234	0.0111
C ₂ -C ₄	0.0033 ^g	0.0024 ^g	0.0081 ^g	0.0042 ^g	0.0227	0.0137	0.0137 ^g	0.0095 ^g
H ₂ O	0.0205	0.0352	0.0275	0.0435	0.0851	0.0978	0.0664	0.0510
H ₂ S	0.0177	0.0123	0.0353	0.0210	0.0006	0.0083	0.0209	0.0281
NH ₃	NA ^h	NA	NA	NA	NA	NA	0.0015	0.0037
C ₆ H ₅ OH	NA	NA	NA	NA	NA	NA	0.0236	0.0050
C ₂						(0.0100)	(0.0100)	(0.0100)
Total					0.9996	0.9932	1.0015	1.0000
<u>Net carbon content of products, wt. %</u>								
Spent shale	69	65	38	34	29	25	25	31.2
Oil	26	29	44	59	37	40	40	37.9
Gas	5	6	17	9	30	19	19	9.3
Aqueous	NA	NA	0.09	NA	NA	NA	14	1.6
Total	100	100	99	102	96	84	98	100.0
<u>Net higher heating value, Btu/lb raw shale</u>								
Feed - shale	3500 ⁱ	2813 ⁱ	3500 ⁱ	2813 ⁱ	3550	2700 ⁱ	2700 ⁱ	2813
Products - shale	2200	1600	1170	910	810	650	650	834
- oil	845	845 ^f	1454 ^f	1688 ^f	1060	1130	1130	1667
- gas	430	350	1020	519	580	550	245	
- aqueous	NA	NA	2	NA	NA	NA	415	72
Products/feed	0.99	0.99	1.04	1.11	0.69	0.86	1.02	1.00

^aE. L. Youngblood, R. Gibson, and A. D. Ryan, "Hydroretorting of Chattanooga Shale," ORNL/TM-7987 (in preparation).

^bIGT test reported in IGT 1980a.

^cIGT test reported in IGT 1980b.

^dData of 80 PDU-2 adjusted to add estimated quantities of phenol, NH₃, and H₂S to the aqueous phase.

^eEstimated design basis for Chattanooga shale.

^fEstimated from density of 0.936 g/ml measured in ORNL-4 and ORNL-6 and oil properties from 80 PDU-2. Carbon content 86.5 wt. %. Higher heating value 17,700 Btu/lb.

^gAssumes average molecular weight of 39.35 and 82.5 wt% carbon as determined in 80 PDU-2.

^hNA is not available.

ⁱEstimated, not measured.

5.1.1 ORNL laboratory experiments

The ORNL experiments were conducted by collecting and measuring the products from a slow heating of nominally 1-lb (500-g) batches of granular Chattanooga shale to a temperature of 1220°F (660°C). Experiments ORNL-2 and ORNL-3 were conducted with shale samples US 70 and 3178 using argon at atmospheric pressure as the cover gas. Water and oil were condensed and weighed. The product gas flow rate and composition were measured with a wet test meter and gas chromatograph. The spent shale was weighed and analyzed.

Experiments ORNL-4 and ORNL-6 were conducted using batches of the same two types of Chattanooga shale with hydrogen at a pressure of 500 psia (3.4 MPa) as the purge gas. Water and oil were again condensed and weighed. The product gas flow rate and composition were measured with an orifice meter and gas chromatograph. The oil from both tests was determined to have a density of about 0.936 g/ml. The aqueous product from experiment ORNL-4 was determined to have an organic carbon content of 0.51 wt.%, possibly from phenols near their limits of solubility. Detailed mass balances for the measured and adjusted data of the hydrogen purge experiments of ORNL-4 and ORNL-6 are presented in Appendix B and summarized in Table 5.2. These data indicate that the organic oxygen content of the raw shale must have been 2.5 to 3% and that the fractional oil yields by weight were 0.082 and 0.095 (21 and 24 gal/ton). The adjusted data for the raw shale composition used in Run ORNL-6 (sample 3178) was used as the reference design composition. The yield and composition of the spent shale and the oil yield were weighted heavily in selecting the design basis data but were modified slightly on the basis of the engineering scale data with New Albany shale to be described in the following section.

5.1.2 IGT bench-scale and process development experiments

The bench-scale (79 BSU-2) and process development unit (80 PDU-2) experiments with New Albany shale are reported in detail in IGT quarterly progress reports (IGT 1980a and IGT 1980b). The bench-scale unit consists of an electrically heated, 4 in. (0.1 m) diam by 9 ft (3 m) tall hydroretort with provisions for condensing and weighing the oil and aqueous products, weighing the feed and spent shale, and measuring the gas flows. Run 79 BSU-2 was conducted with a shale flow rate of 79 lbs/h (98.8 lbs/ft³/h), a pressure of 527 psig, a bed height of 9 ft, average bed temperature of 1151°F, maximum bed temperature of 1260°F and hydrogen feed rate of 17.8 scf (60°F, 30 in. Hg) per pound of raw shale. The measured fractional oil yield was 0.061 (14 gal/ton at the measured density of 1.036 g/ml) but the elemental material balances were rather poor (94% for carbon, 91% for hydrogen, and 156% for oxygen).

The process development unit utilizes a two stage, adiabatic, 36 in. (0.9 m) diam hydroretort with an active bed height of 10 ft in each stage. Oil and water product from the two stages are collected separately in water scrubbers. Other flows are measured. Run 80 PDU-2 was conducted with a shale feed rate of 1059 lbs/h (123 lb/h/ft³ in both stages), a pressure of 406 psig, average bed temperature of 575°F (stage 1) and 1224°F (stage 2), maximum bed temperature of 1355°F (stage 2), and preheated hydrogen feed rates of 18.96 scf/lb (stage 1) and 13.17 scf/lb (stage 2). Significantly, it was necessary to add air to the second stage at a rate of 0.57 scf/lb shale feed to burn hydrogen and maintain the bed temperature.

A detailed mass and energy balance for the measured and adjusted data of the run 80 PDU-2 with New Albany shale is presented in Appendix B and summarized in Table 5.2. The adjusted data makes allowance for ammonia, additional hydrogen sulfide and carbon that might have been collected in the water scrubbers. The material balance for carbon (87%), hydrogen (103%), and oxygen (123%) improve appreciably (to 98%, 102%, and 99%, respectively) if it is assumed that about 14% of the carbon is collected as phenols (conceivably from the high organic oxygen content of the New

Albany shale). Data from this run that were used to establish a basis for the reference design included spatial flow rates, the oxygen requirement, gas compositions, and oil properties.

The completed elemental material balance and energy balance across the hydroretorts that is used as the basis for the reference plant design is presented in Table 5.3. Derived properties of the reference raw oil and hydrotreated oil produced from Chattanooga shale are presented in Table 5.4. Properties of the raw oil were estimated based upon the measured yield and specific gravity from experiment ORNL-6 and elemental oil compositions relative to original shale compositions from 80 FDU-2. The hydrogen requirement for hydrotreating and properties of the hydrotreated oil were based upon data from IGT (1980b).

5.1.3 Reference design of hydrocarbon recovery process

The reference design for technical and economic evaluation of a conceptual plant for the recovery of hydrocarbons from Chattanooga shale has been based on a shale feed rate of 100,000 tons/d, which will yield about 46,000 bbl/d of hydrotreated oil product. Such a relatively large plant is desirable to achieve economies of scale. The solids handling requirements are formidable and in the upper range of existing similar operations but appear to be manageable.

A schematic diagram of the reference design selected for the conceptual hydrocarbon recovery plant is shown in Fig. 5.1. Estimated mass flows of the process streams and an energy balance for the plant are presented in Table 5.5. The following will briefly describe the process. Equipment requirements and costs will be discussed in Chapter 6.

The mined shale (minus 12 in size) is crushed to minus 1.5 in size and the screened minus 3/8 in portion (representing about 10% of the total and which would tend to plug the hydroretorts) is conveyed directly to the storage area for the minerals recovery process. The bulk of the sized shale is stored and fed, as needed, to the hydroretorts at nominally 500 psia through lock hoppers. The shale is heated by the rising overhead gas

Table 5.3. Derived design basis mass and energy balance across hydroretorts

	Mass per unit mass of raw shale							HHV ^a
	Total	C	H	S	O	N	Ash	
<u>Feed</u>								
Shale	1.0000	0.1405	0.0181 ^b	0.0492	0.0391	0.0050	0.7481	2813
Gas	0.2576	0.0428	0.1682		0.466			10696
O ₂	0.0100				0.0100			
CO	0.0594	0.0594	0.0255		0.0339			258
CO ₂	0.0037	0.0010			0.0027			
H ₂	0.1627		0.1627					9918
CH ₄	0.0218	0.0163	0.0055					520
Total	1.2576	0.1833	0.1863	0.0492	0.0857	0.0050	0.7481	13509
<u>Product</u>								
Shale	0.8212	0.0438	0.0020	0.0218	0.0043	0.0012	0.7481	834
Oil	0.0939	0.0814	0.0098	0.0009	0.0011	0.0007		1662
Gas	0.2848	0.1558	0.1680	0.0265	0.0345			10941
CO	0.0495	0.0212			0.0282			215
CO ₂	0.0085	0.0022			0.0063			
H ₂	0.1563		0.1563					9528
CH ₄	0.0329	0.0246	0.0083					785
C ₂ -C ₄	0.0095	0.0078	0.0017					206
H ₂ S	0.0281		0.0016	0.0265				207
Aqueous	0.0577	0.0023	0.0065		0.0458	0.0031		72
H ₂ O	0.0510		0.0057		0.0453			
NH ₃	0.0037		0.0006			0.0031		36
C ₆ H ₆ O	0.0030	0.0023	0.0002		0.0005			36
Total	1.2576	0.1833	0.1863	0.0492	0.0857	0.0050	0.7481	13509

^aHigher heating value in Btu/lb.

^bIncludes hydrogen and oxygen from moisture in raw shale.

Table 5.4. Estimated properties of raw oil from hydroretorts and hydrotreated oil product

	New Albany shale	Chattanooga shale	
	Raw oil ^a	Raw oil ^b	Hydrotreated oil ^c
Yield from raw shale			
Mass/unit mass shale	0.0642	0.0939	0.0922
Gal/ton	16.1	24.0	27.5
Liters/metric ton	67.2	101.3	114
Elemental composition, wt. %			
C	85.4	86.7	85.6
H	10.1	10.4	14.3
O	2.4	1.2	0.01
S	1.2	1.0	<0.01
N	0.9	0.7	0.08
	100.0	100.0	100.00
Specific gravity	0.956	0.936	0.806
API gravity	16.5	19.7	44.0
Higher heating value, Btu/lb	17,640	17,700	19,940
Higher heating value, Btu/gal	140,600	138,000	134,000
Hydrotreat H ₂ consumption, scf/bbl			2600

^aComposite oil from test 80 PDU-2.

^bOil properties on adjusted data from ORNL-4.

^cEstimated from data in DOE/ET/14102-1.

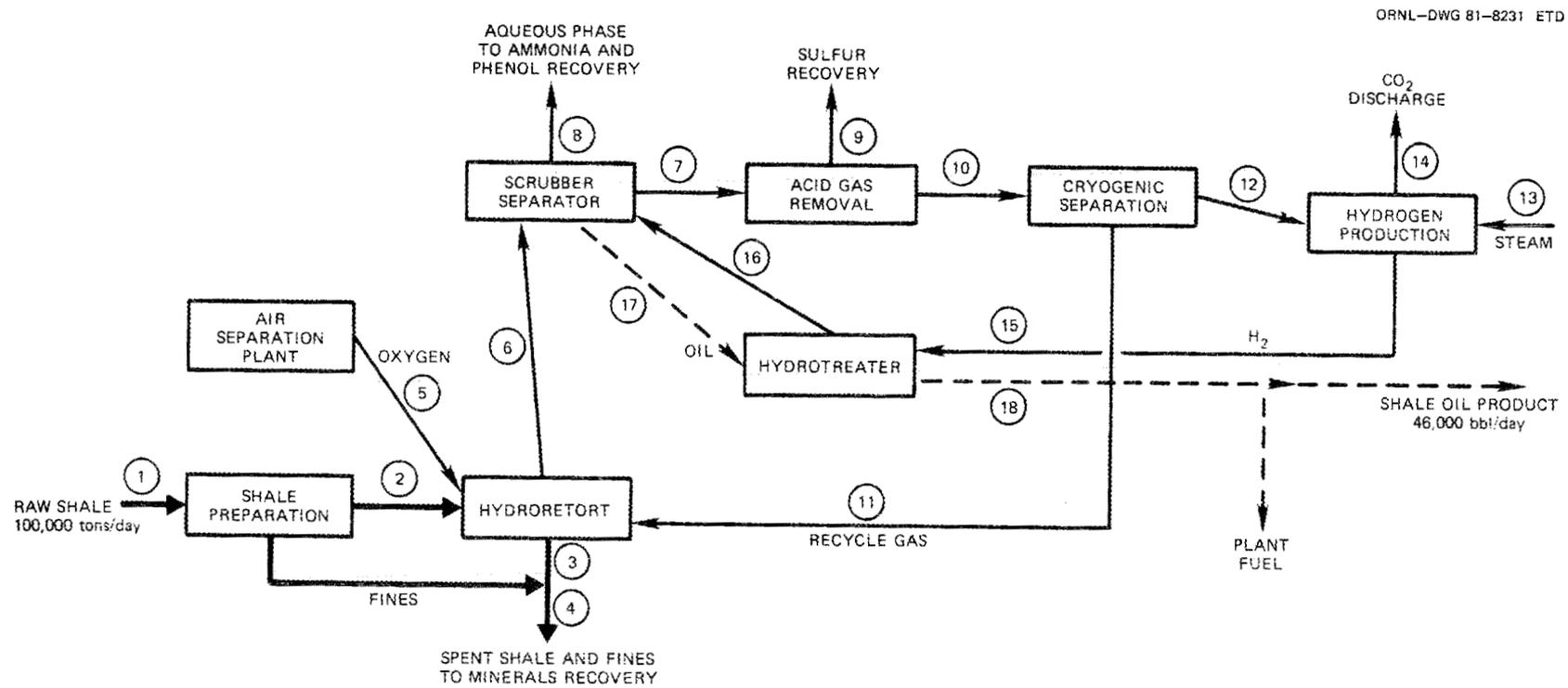


Fig. 5.1. Schematic diagram of shale hydroretorting process.

Table 5.5. Estimated overall mass and energy balance for hydroretorting process

	Shale	O ₂	CO	CO ₂	Mass flow (1000 lb/h)							Phenols	Oil	Total	Temp. (°F)	Pressure (psia)
					H ₂	CH ₄	C ₂ -C ₄	H ₂ O	H ₂ S	NH ₃						
1 Shale to prep plant	8333												8333	70	15	
2 Shale to retorts	7500												7500	70	500	
3 Spent shale	6159												6159	150	15	
4 Shale to minerals recovery	6992												6992	100	15	
5 Oxygen to retorts		75											75	100	550	
6 Retort overheads			371	64	1172	247	71	382	211	28	23	704	3273	150	450	
7 Combined off gas			445	64	1220	266	83	390	220	34	23	704	3454	100	500	
8 Aqueous to ammonia, phenol recovery				36					220				256	100	15	
9 Acid gas to sulfur recovery			445	28	1220	266	88						2047	100	450	
10 Clean gas			445	28	1220	164							1857	1400	550	
11 Recycle gas to retorts						102	88						190	1400	450	
12 Gas to hydrogen production								366					366	1400	450	
13 Steam to hydrogen production				388									388	100	15	
14 Carbon dioxide discharge			74		78	15							167	800	2200	
15 Hydrogen to hydrotreater			74		48	19	17	8	9	6			181	100	500	
16 Hydrotreater off gas												704	704	100	15	
17 Raw oil												692	692	100	15	
18 Hydrotreated oil												541	541	70	15	
19 Oil product																

Input	Mass flow (10 ³ lbs/h)	Higher heating value (10 ⁶ Btu/h)
Raw shale (100,000 tons/d)	8333	23441
Oxygen	75	1420
Electricity at 10,000 Btu/kWh		
	8408	24861

Output	Mass flow (10 ³ lb/h)	Higher heating value (10 ⁶ Btu/h)	
Spent shale	6159	5037	30.1%
Fines	833	2343	43.4%
Oil product (46,000 bbl/d)	541	10788	3.3%
Sulfur	207	824	1.3%
Ammonia	34	329	1.1%
Phenols	23	277	
Carbon dioxide	436		
Process water	24		
Fuel oil burned	151	3011	20.8%
Other energy to atmosphere		2152	
	8408	24861	

in the top section of the hydroretorts, is hydroretorted in a center section in which some hydrogen is burned with oxygen to maintain the desired temperature of 1200 to 1300°F, is cooled in the bottom section as it exchanges heat with a portion of the recycle gas stream, and discharged through lock hoppers.

The cooled overhead stream from the hydroretorts contains oil as vapor and mist, water, light hydrocarbons, CO, CO₂, H₂S, NH₃, and the unreacted hydrogen. This stream is combined with the off-gas stream from the hydrotreaters and treated with deentrainment devices and scrubbers to separate the aqueous phase and oil from the gas. The aqueous phase is separated from the oil and treated by the Chevron process for recovery of ammonia and phenols. The oil stream flows through intermediate storage to hydrotreaters. The gas stream is sent to a selective acid gas removal system where virtually all of the H₂S and some of the CO₂ is removed. The stream containing the H₂S and CO₂ is treated with the Claus process for sulfur recovery and the SCOT tail-gas cleanup process prior to discharge to the atmosphere.

The cleaned, high pressure, high-flow-rate gas stream is then treated by a cryogenic process to separate a stream that is concentrated in methane and other light hydrocarbon gases. The main stream containing most of the hydrogen and carbon monoxide is boosted in pressure, reheated (using an oil fired furnace and heat exchange with the spent shale) and returned as a recycle gas to the hydroretorts. The methane and light hydrocarbons are used for hydrogen production in a series of operations involving catalytic reforming with steam at 1400°F and 200 to 400 psia (oil fired), removal of most of the large volume of CO₂ produced in the process, and methanation. The relatively pure hydrogen stream is compressed and fed to the hydrotreaters where it is used to treat the raw shale oil with an appropriate desulfurization, denitrification catalyst at about 800°F and 2000 psia.

The energy balance shown at the bottom of Table 5.5, and particularly the requirement for electricity and internal fuel oil consumption, was not estimated in detail but was performed using factors that were derived from design data on related processes. The derived data, however, in

which the product oil contains about 43% of the input energy of the shale, is believed to be a reasonable estimate based upon the current stage of knowledge about the process.

5.2 Metals Recovery Process

Considerable effort was expended during the period from 1944 to 1960 in investigating the Chattanooga shales, mainly for their uranium and potential oil content. The early investigations have been summarized in a recent report by Mutschler (1976). The continuing depletion of higher grade U.S. reserves, along with the possible future growth in demand of the nuclear industry, led DOE to execute a contract with Bendix Field Engineering to determine the feasibility of large-scale production of uranium from the Chattanooga shale. Mountain States Mineral Enterprises, Inc., as a subcontractor to Bendix, performed this study (Mountain States 1978), with the mining and environmental aspects studied separately and reported by two other firms - Cleveland Cliffs (Hoe 1979), and P. R. Toups (1979), respectively.

Mountain States concluded that a coproduction plan involving the production of oil from shale by hydroretorting, along with uranium production and possibly other metal by-products, was not only feasible, but economically viable. Mountain States made use of the Swedish experience in processing shale for uranium (Ranstad process) for delineating some of the steps in their coproduction plan (Andersson, 1979).

Since some of the data in the Mountain States paper (based on analyses given in the Mutschler report) were old and fragmentary, recent samples of raw and hydroretorted shale were obtained from IGT and analyzed to verify their metals content. Additional data on other Devonian shales were obtained from U.S. Geological Survey reports (Leventhal 1979 and Leventhal 1978).

Exploratory experiments at ORNL on leaching a number of the 'critical' metals from both raw and hydroretorted Chattanooga shale samples yielded very encouraging results (Silverman, 1981). The purpose of the following sections will be to develop a reference design for technical and

economic evaluation of minerals recovery from Chattanooga shale on the basis of information available in the Mountain States report, in Swedish reports based on the Ranstad process, from recent ORNL experimental work, and other information from the literature. An alternative, and possibly improved process, which would utilize leaching with hydrochloric acid, has also been studied at ORNL (Gilliam 1981) but has not been employed for the reference design.

5.2.1 General description of process

A conceptual flow sheet for process evaluation has been developed (Fig. 5.2) which is similar in many respects to that presented in the Mountain States report. The hydroretorted shale and fines containing about 33% of the carbon and 43% of the sulfur originally present in the shale, are roasted in two steps: one hour at 250 to 300°C to remove the remaining carbon and a second one-hour roast at 320 to 500°C to remove nearly all of the remaining sulfur. Heat from the roasting process is used to generate steam for process heating. The sulfur dioxide is recovered and used for sulfuric acid production.

The roasted shale is leached with a 20% sulfuric acid solution by a countercurrent percolation treatment. The leached residue is neutralized with crushed limestone, compacted and reinserted into the mine excess and fines are transported with other tailings to a shallow dam. The leachate solution should contain about 80% of the uranium and molybdenum, about 25% of the Al, Fe, K, Na, and Mg, plus the trace elements (amounts to be determined by experiment). Sulfuric acid consumption is 400 lb/ton of shale, ~90% of the acid production available from all of the sulfur removed from the shale.

A solvent extraction process (Sialino, 1977), employing a solution of a tertiary amine (Alamine-336) in an organic diluent, removes uranium, molybdenum, and some vanadium (V) from the aqueous leachate into the organic solvent. This solvent is then stripped to remove U with an aqueous solution containing 1.5M NaCl, 0.3M MgSO₄, and 0.5M Na₂SO₄. The uranium is precipitated as the diuranate and calcined to produce U₃O₈. Molybdenum is stripped from the solvent with Na₂CO₃ (after U removal) to yield

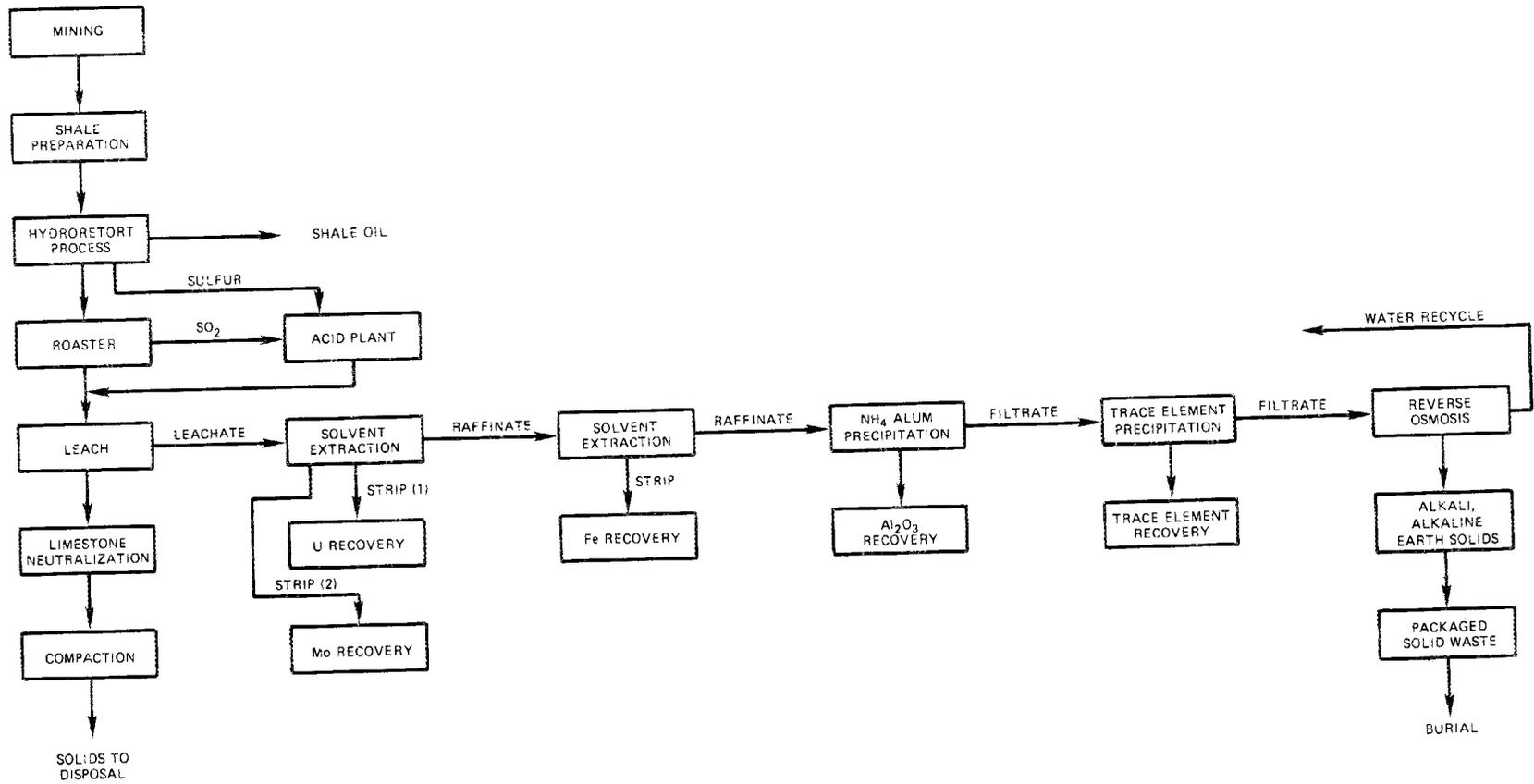


Fig. 5.2. Chattanooga shale processing plant.

Na_2MoO_4 , which is purified later and converted to MoO_3 . The organic solvent is washed with H_2O before return to the extraction step.

The raffinate from the first extraction cycle (the tertiary amine containing Al, Fe, alkalis, alkaline earths and the trace elements) is run through another extraction cycle in which iron is separated (Seeley 1981a and 1981b) from the remaining elements by using a primary amine, Primene JM-T. The iron is stripped from the organic layer with DTPA, precipitated as the hydrous oxide, and converted to Fe_2O_3 by calcination.

Aluminum is precipitated at 5 to 10°C as the ammonium alum salt $(\text{NH}_4)_2\text{SO}_4 \cdot \text{Al}_2(\text{SO}_4)_3 \cdot 24\text{H}_2\text{O}$, by the addition of ammonium sulfate to the raffinate from the iron extraction cycle (St. Clair, 1944). The alum salt can be redissolved in hot water and recrystallized for purification purposes before calcination to Al_2O_3 . An improved procedure (Seeley 1981a) used here for handling the ammonium alum is dissolution and subsequent precipitation of hydrous Al_2O_3 by the addition of gaseous ammonia. This may allow more efficient recycle of the $(\text{NH}_4)_2\text{SO}_4$ solution, avoid a second recrystallization step, and provide a high purity alumina product since iron and other tri- and tetravalent metals have already been removed by the solvent extraction step.

The solution which remains after the alum precipitation, containing sulfate salts of the alkalis and alkaline earth metals, as well as those of the trace elements (Co, Mn, Ni, Cu, Zn, Cr, V), is neutralized with sodium hydroxide to an alkaline pH of 9 to 10. The hydroxides of Co, Mn, Ni, Cu, Zn, Cr will all be precipitated, along with magnesium, present in much higher concentration, whose hydroxide is slightly soluble. However, the dissolution of all except magnesium is accomplished by the addition of ammonia to form the soluble metal complexes. Purification and reprecipitation of these hydroxides is accomplished by heating to drive off NH_3 ; the solids are dewatered and calcined to yield a concentrated mixture of solid metal oxides which can then be shipped to an industrial metals separation plant.

The final tailings solution, consisting of the alkali and alkaline earth sulfates, is treated by reverse osmosis (Larson, 1979) to concentrate the salts, which can then be packaged to form a cement-like solid that should be less susceptible to leaching by ground waters.

5.2.2 Unit process descriptions

Roasting - The solid residue after hydroretorting contains about 33% of the carbon and about 43% of the sulfur originally present in the shale (Fig. 5.3). Also, since the shale is retorted under a reducing atmosphere, some of the metals contained in it remain or are reduced to lower valence states. This was demonstrated by ORNL experiments (Silverman 1981) and the Columbia studies (1955); e.g., lower recoveries of uranium are attained from leaching hydroretorted shale than from raw shale. Although the hydroretorted residue can be leached directly for its mineral content, energy recovery, sulfur removal, and improved properties, environmentally acceptable disposal makes it advantageous to roast the shale.

Surface areas, micro and macropore volumes, and porosities of roasted shale were examined as a function of roasting temperature by the Mineral Beneficiation Laboratory at Columbia University (1955). Their data were used to select the experimental conditions for roasting the shale. Roasting is suggested in two discrete steps: (1) 250 to 300°C for 1 h to remove the carbon (energy), and (2) 320 to 500°C for one hour to remove most of the sulfur, which is converted to sulfur dioxide, scrubbed, and sent to the on-site sulfuric acid production plant.

Leaching - The Mountain States process flow sheet recommends crushing the shale in a ball mill to ~48 mesh to provide material for a 50% solids slurry which is leached with 10% by weight sulfuric acid solution (200 lb acid/ton of shale). The ORNL laboratory experiments (Silverman 1981) as well as those performed at Columbia (1955) indicate that it is possible to leach uranium as well as other metals efficiently from the roasted shale without further crushing beyond the 4 to 16 mesh size. This size material has a macropore volume of ~0.19 cm³/g and a porosity of ~38%.

The design basis leaching process assumes use of a countercurrent percolation treatment, with 20% sulfuric acid as the lixivium, for 24 h at 70 to 80°C. It is estimated that about 80% of the uranium and molybdenum in the roasted shale will be leached, along with ~25% of the aluminum, iron, alkalis, and alkaline earth metals. Experiments will be needed to

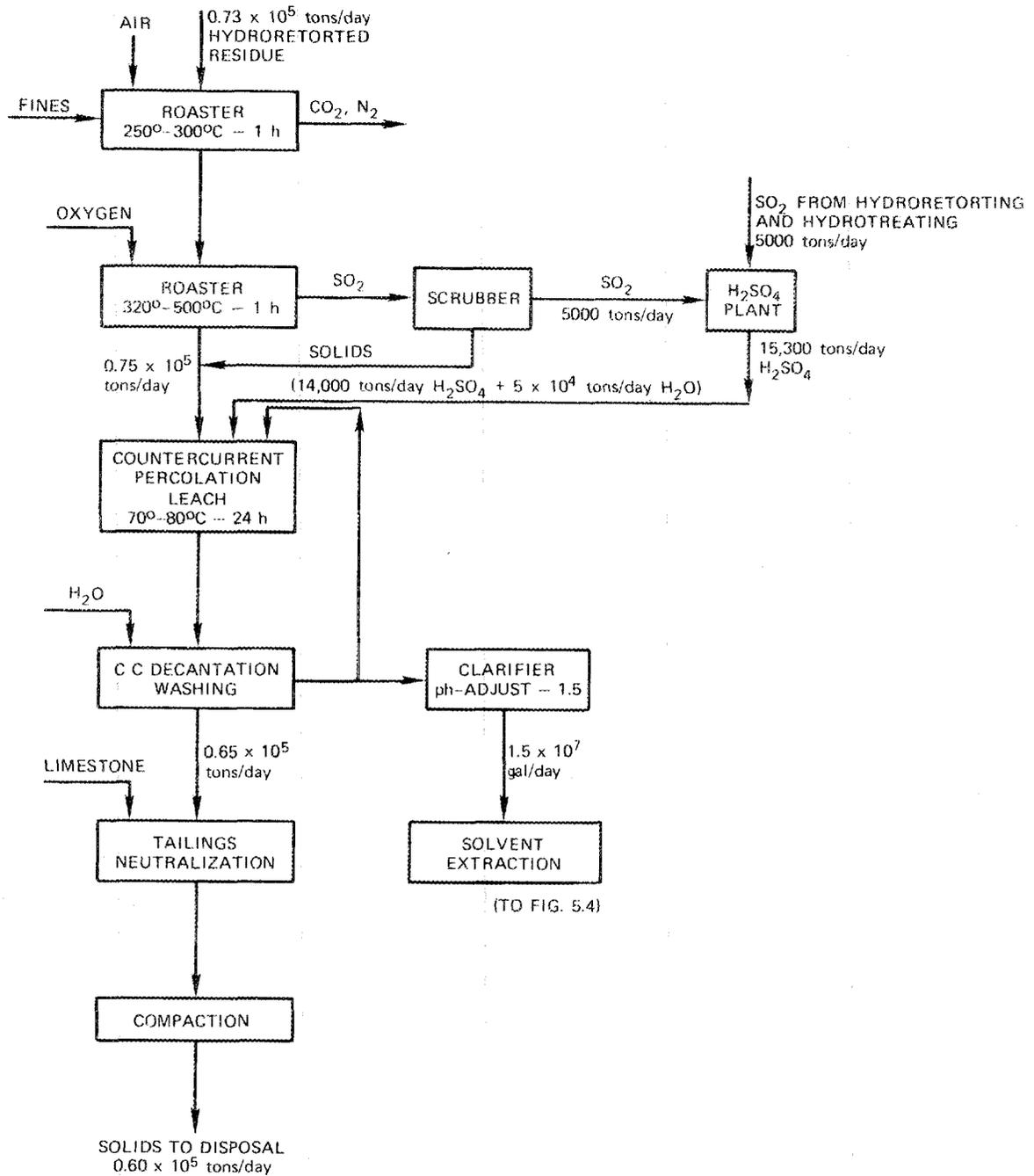


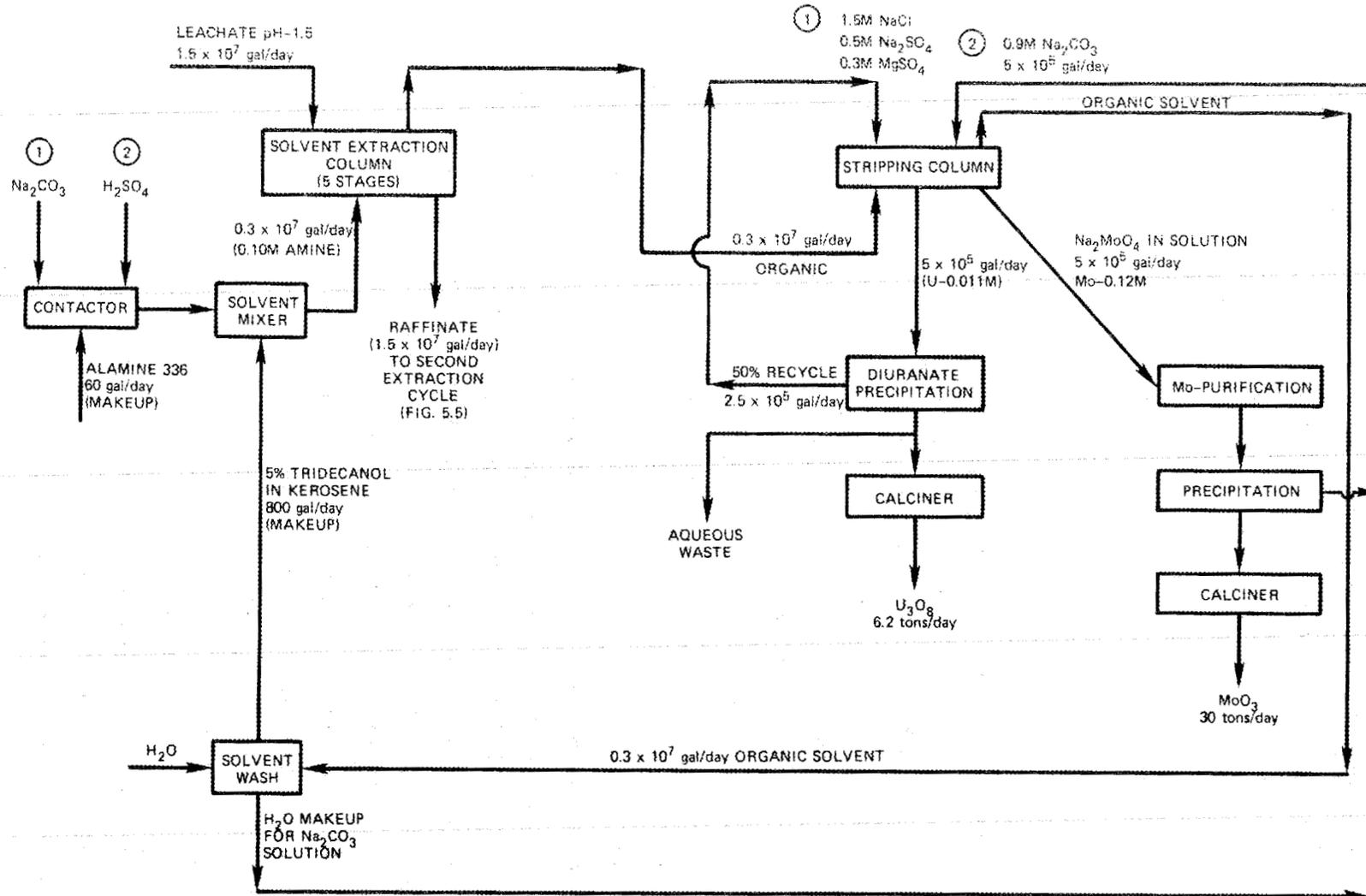
Fig. 5.3. Process detail - roasting and leaching.

determine what proportion of the various metal constituents in shale will be leached by the 20% acid solution. Mountain States has estimated a 60% recovery for a number of elements (uranium, cobalt, nickel, etc.) based on using a 10% acid solution with a 6-h leaching period.

Tailings -- The residue remaining after leaching will be washed and mixed with crushed limestone to neutralize any remaining acidity. Its acid content should be low because the countercurrent leaching system is planned to provide a leachate of pH ~1.5 for the following solvent extraction steps. Practically all of the sulfur in the hydroretorted shale is removed during the roasting operation; those metallic constituents that are not dissolved during the leaching process will remain in the roasted shale as oxides, silicates, and sulfates that are not soluble in groundwater. Hydraulic backfilling cannot put all of the neutralized residue back into the mined-out area. Preliminary tests at ORNL indicate that the density of the residue can be almost doubled by a compacting pressure of 5000 lb/in.². Compaction of some type probably might be used to minimize the volume of the residue for disposal.

Metal recovery -- The leachate (adjusted to pH 1.5) is clarified before solvent extraction (Fig. 5.4). The organic extractant is the tertiary amine, Alamine 336 (0.05M -- about 20 g/L) dissolved in a solvent consisting of a 5% solution of tridecanol in kerosene. Because the density difference between the organic extractant and the aqueous feed is about 0.4 g/cc (1.2 to 0.8), countercurrent pulsed column extraction (with about 5 stages) is recommended. Available data (Seeley and Crouse 1971) indicate that all of the uranium and molybdenum and any vanadium (V) will be completely extracted. Preferential stripping of the uranium is accomplished (Sialino, 1977) with a solution that is 1.5M NaCl, 0.3M MgSO₄, and 0.5M Na₂SO₄. This stripping solution will permit satisfactory precipitation of uranium as the uranate and subsequent calcination to U₃O₈. This stripping reagent can also be recycled (50% rate); the sodium chloride which is rejected can be replaced with fresh chloride.

Molybdenum, which remains in the solvent after uranium stripping, is subsequently stripped with sodium carbonate to yield a solution of sodium molybdate. The latter is purified to remove any phosphate or vanadium



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Fig. 5.4. Uranium and molybdenum recovery.

before molybdenum is precipitated and calcined to produce MoO_3 . The solvent can be easily reused after washing with water to prevent carryover of carbonate to the extraction section.

The raffinate (pH 1.5) from the solvent extraction step (Fig. 5.5) contains the sulfate salts of aluminum, iron, alkali and alkaline earth metals as well as the trace elements (Co, Cr, Mn, Ni, V, and Zn). In order to obtain aluminum in pure enough form for metal production by a precipitation process, it is necessary to remove iron beforehand. This is accomplished (Seeley 1981b) by another solvent extraction cycle in which iron is separated from the other elements by using a high-molecular-weight, branched primary amine, Primene JM-T sulfate as the extractant (0.87M - a 30 wt % solution) in a diluent such as toluene or diethylbenzene. The amine is first scrubbed with a Na_2CO_3 solution for removal of low-molecular-weight impurities. Then it is contacted with 1N H_2SO_4 and equilibrated with 1M Na_2SO_4 solution that is adjusted to pH 1.5 with H_2SO_4 . It is estimated that less volume reduction can be attained (~4 vs 20 in the one above) in this extraction cycle (3 to 4 stages), because of the high iron content (0.42 M) in the feed. The iron is stripped from the organic layer by DTPA (diethylenetriaminepentacetic acid), precipitated as the hydrous oxide, and converted to Fe_2O_3 by calcination. It should be pure enough to serve as a feed for direct reduction processes, although even good iron ore (>65% Fe), commands a relatively low price, \$50/ton.

Aluminum is precipitated (Seeley, 1981a) from the iron raffinate at 5 to 10°C by the addition of ammonium sulfate to form the crystalline ammonium aluminum alum, $(\text{NH}_4)_2\text{SO}_4 \cdot \text{Al}_2(\text{SO}_4)_3 \cdot 24\text{H}_2\text{O}$ (Fig. 5.6). After recovery by filtration, the alum is washed with ammonium sulfate solution. Contamination of this solid has been studied in some detail (St. Clair, 1944). Recrystallization can further reduce contamination. However, an improved procedure for purification consists of its dissolution and subsequent precipitation as hydrous Al_2O_3 by the addition of gaseous ammonia. This may permit more efficient recycle of the ammonium sulphate solution, avoid a second crystallization step, and probably provide a high purity alumina product since iron and several other tri- and tetravalent metals will be removed by the extraction step. Decontamination factors from a

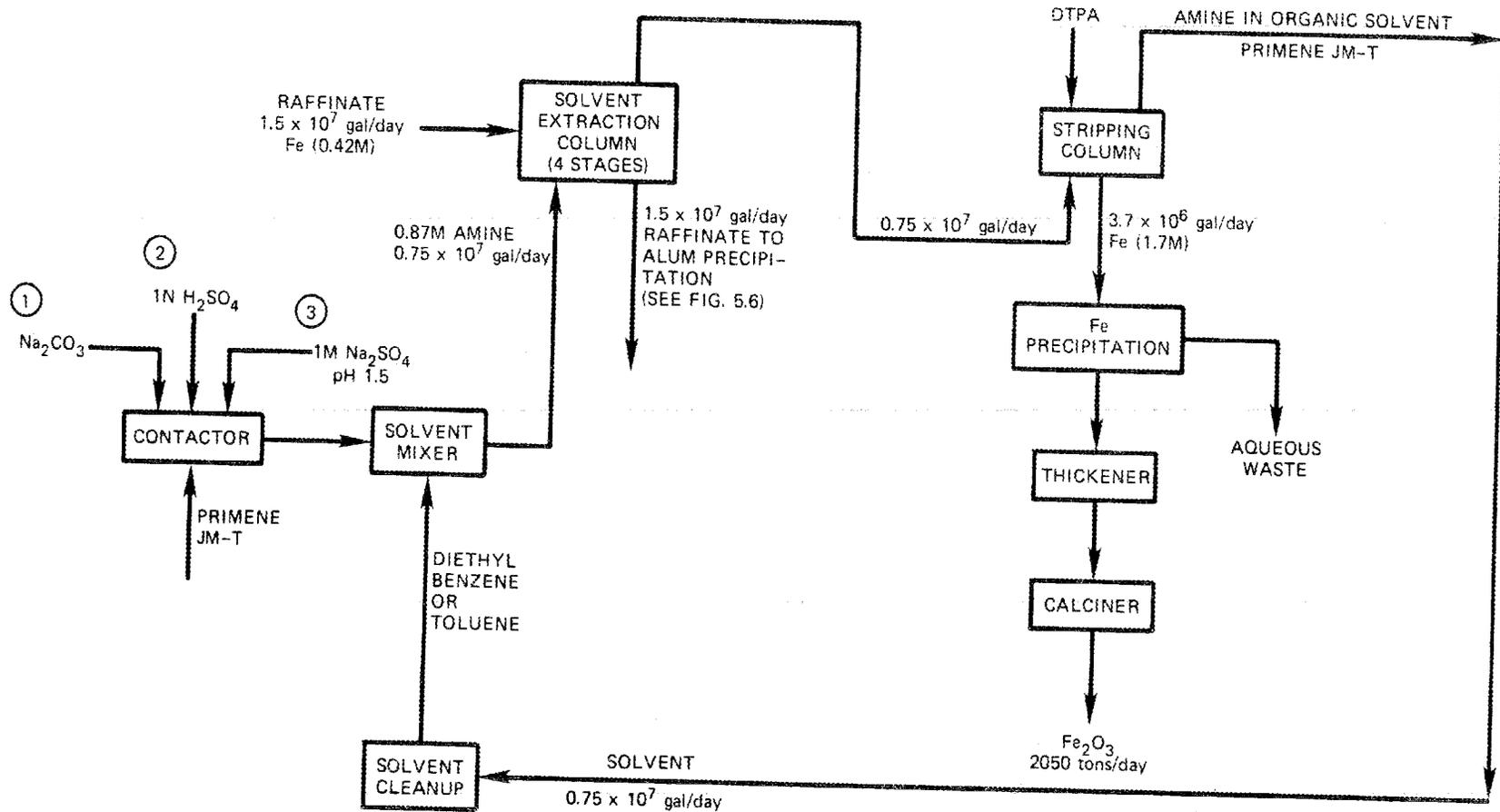


Fig. 5.5. Fe separation and/or recovery.

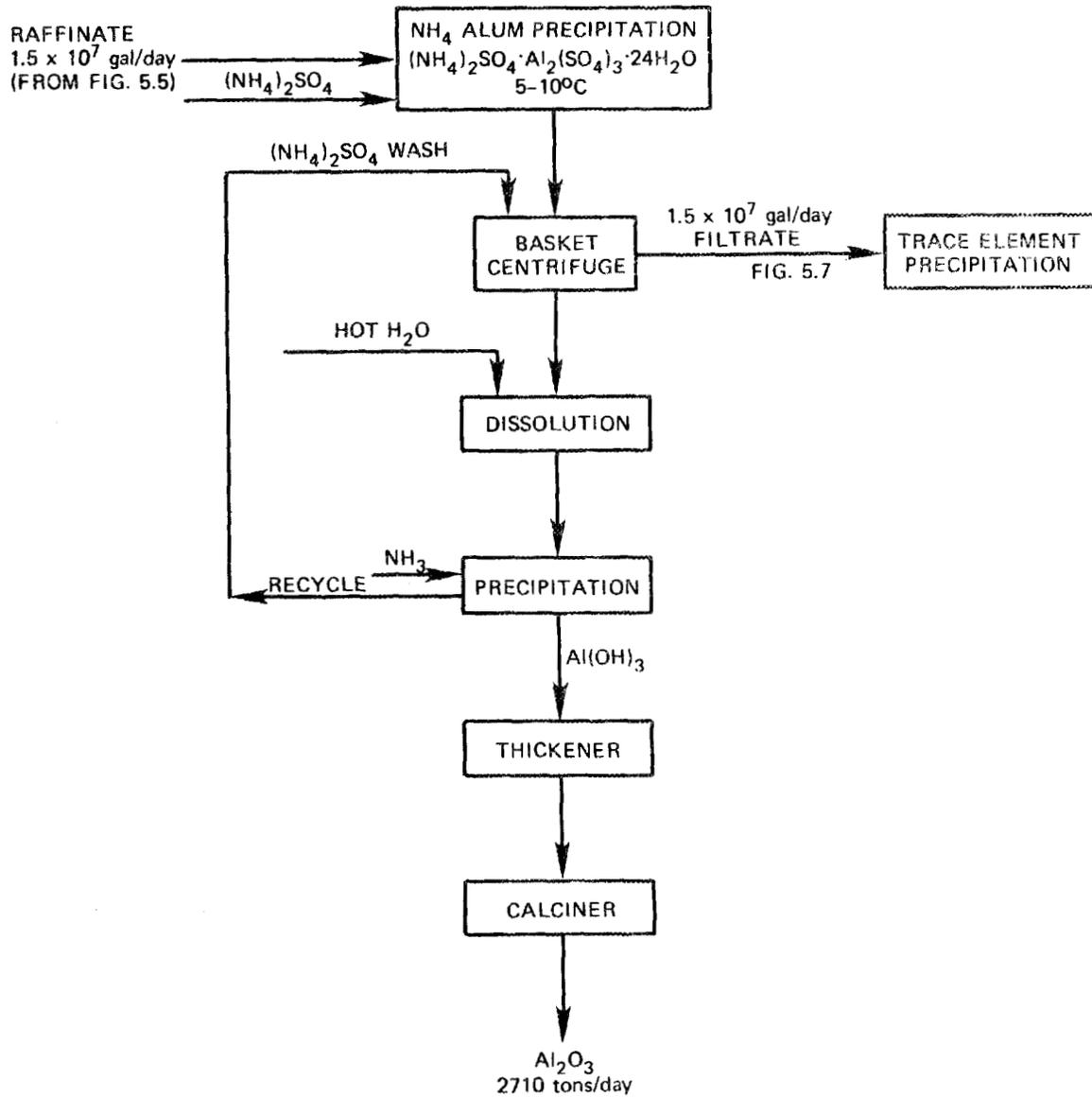


Fig. 5.6. Aluminum recovery.

number of potential interfering elements have been tabulated (Seeley 1981b).

The solution which remains after the alum precipitation, containing sulfate salts of the alkalis and alkaline earth metals, as well as those of the trace elements (Co, Mn, Ni, Cu, Zn, Cr, V), is neutralized with sodium hydroxide to an alkaline pH, 9 to 10 (Fig. 5.7). The hydroxides of Co, Mn, Ni, Cu, Zn, Cr will all be precipitated along with magnesium, present in much higher concentration, whose hydroxide is slightly soluble. However, dissolution of Co, Mn, Ni, Cu, and Zn hydroxides is accomplished by the addition of ammonia to form the soluble metal complexes. Purification and reprecipitation of these hydroxides is accomplished by heating to drive off NH_3 ; the solids are dewatered and calcined to yield a concentrated mixture of solid metals oxides which can then be sold to an industrial metals separation plant (e.g., Amax Freeport plant).

The final tailings solution, consisting of the alkali and alkaline earth sulfates, might be treated by reverse osmosis (Larson, 1979) to concentrate the salts, which can be packaged to form a cement-like solid that is relatively unleachable by groundwaters.

Metal recovery - alternate process - An alternative flow sheet has been devised for a process which differs considerably from that presented above, after the first roasting step has been completed (Fig. 5.8). This process involves an alkaline leach system, employing ammonia and/or ammonium carbonate under oxygen pressure (10 psi), to dissolve the divalent trace elements (Co, Ni, Mn, Cu, Zn) from a shale concentrate containing most of the iron and these elements. The concentrate is obtained by magnetic beneficiation of the roasted shale.

If one examines the list of elements present in the shale with respect to the periodic table, it is noted (Kolm, 1975) that iron, cobalt, and nickel are ferromagnetic transition elements whose compounds are in many cases strongly paramagnetic. Moreover, there are additional transition elements such as chromium, manganese, molybdenum, and vanadium which are paramagnetic and form paramagnetic compounds, whose recovery from shale is also desirable. Conversely, other elements such as aluminum,

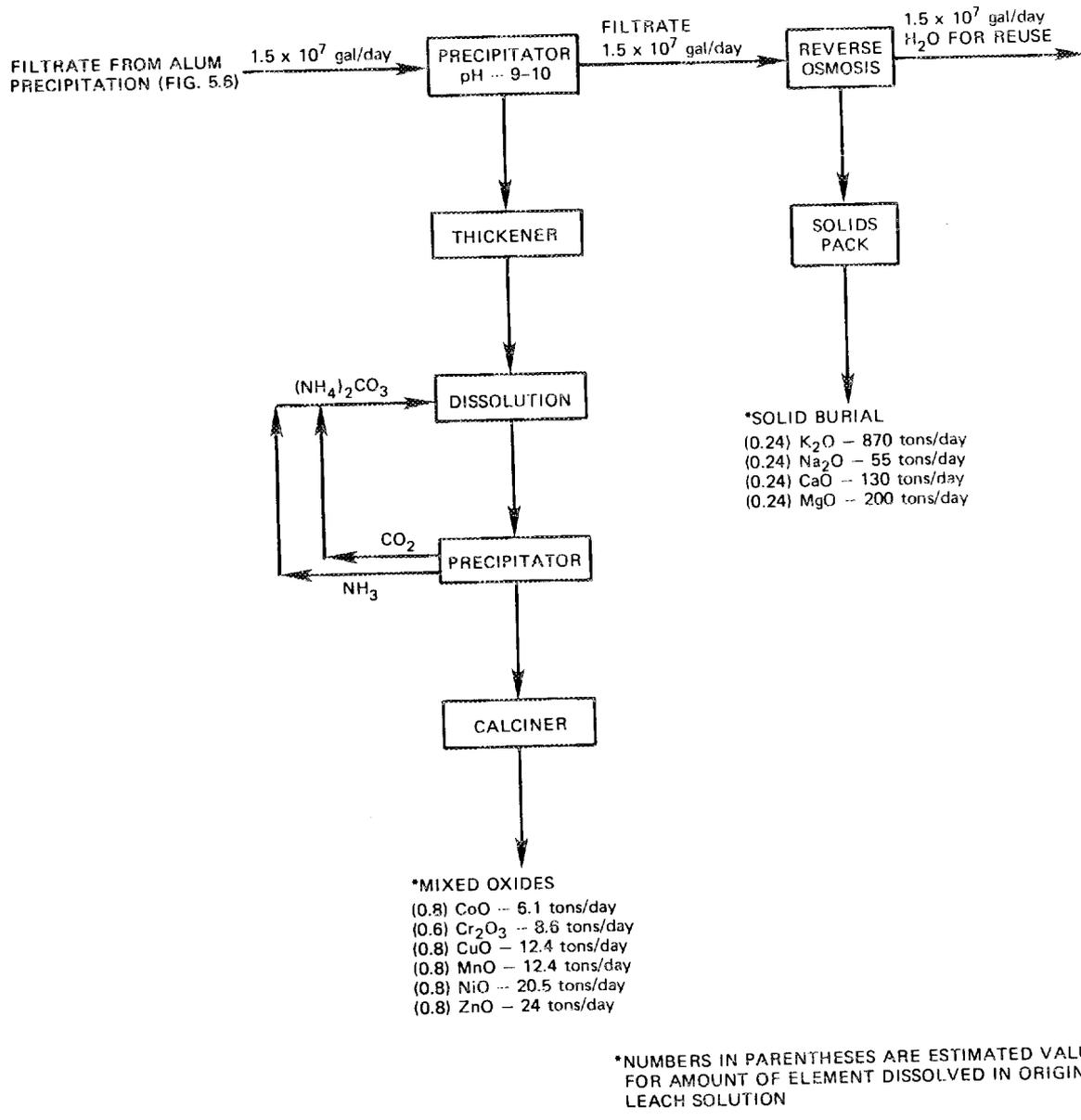


Fig. 5.7. Trace element recovery.

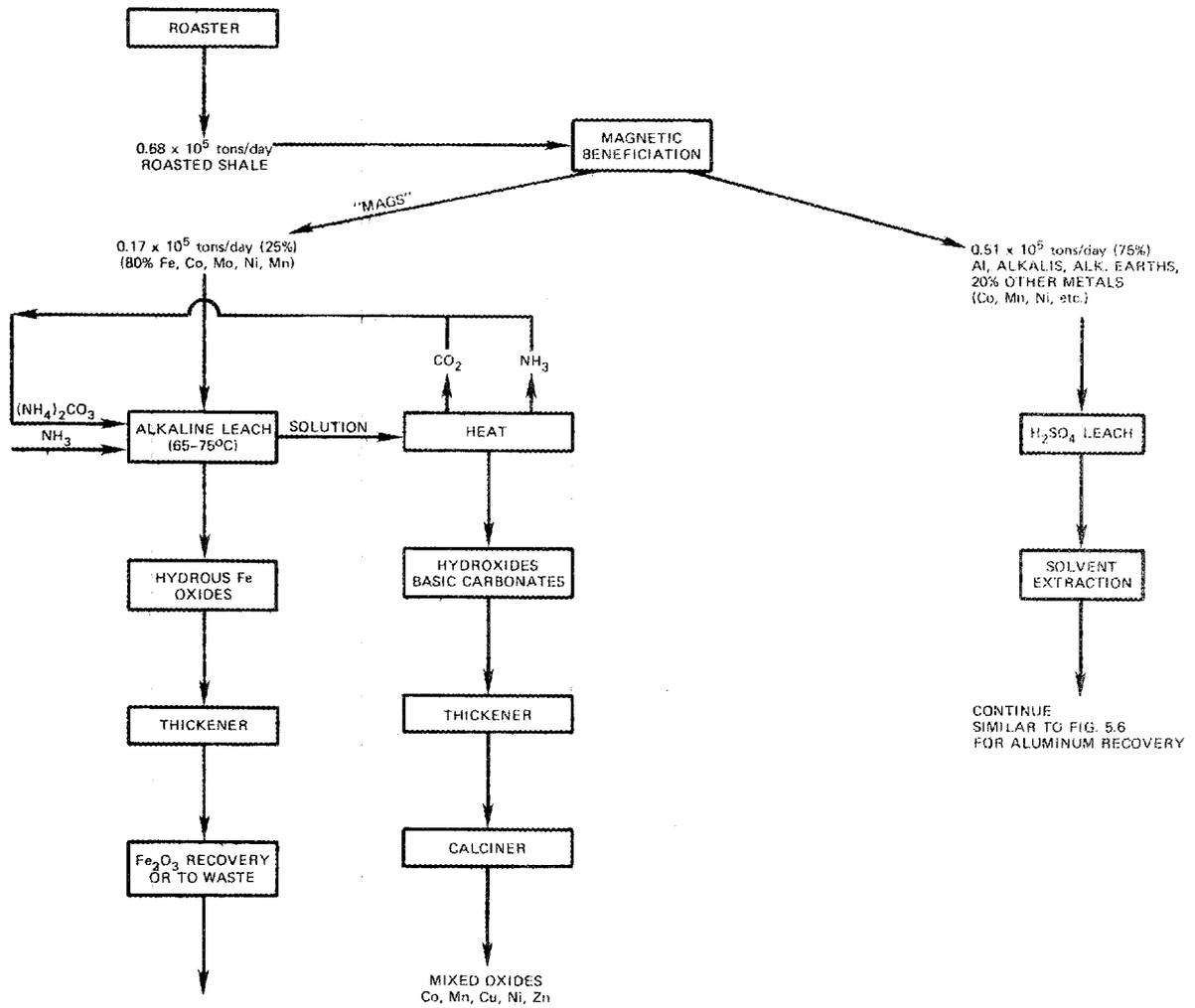


Fig. 5.8. Alternative process for minerals recovery.

silicon, alkalis, and alkaline earth metals mainly form diamagnetic compounds, so these would be expected to remain in the nonmagnetic solids during beneficiation.

A preliminary set of laboratory experiments has been completed at ORNL on several grams of roasted shale using an 11.8 kgauss Frantz separator which indicate that some metallic species can be concentrated by magnetic beneficiation. The roasted shale was crushed, sieved, and separated into two sized portions of -30 + 200 and -200 + 400 mesh. A third portion (-400 mesh) was too fine to be run on this instrument, but a sample was analyzed chemically (along with the separated fractions below). Three sets of magnetically separated fractions, 'mags,' 'middlings,' and nonmagnetic material were obtained from each sized portion when these were run on the Frantz separator. The 'mags,' strongly magnetic even at the low field strength used, contained about 40% of the iron, cobalt, and molybdenum in about 19% of the total weight of material separated. The 'middlings,' representing 25% by weight (but less magnetic than the mags since a higher field strength was required for separation) contained over 40% of the above metals. The combination of 'mags' and 'middlings' contained over 80% of the iron, cobalt, molybdenum, and over 70% of the nickel and uranium. Even better results possibly can be obtained by using larger samples and more refined techniques.

The beneficiation process described above provides a metal concentrate and serves several purposes: (1) it simplifies extraction of the trace elements, since they can be removed from the iron by an ammoniacal leach treatment, which (2) also leaves the iron behind as an insoluble hydrous oxide, permitting its separation and solidification if desired for industrial application; (3) it removes most of the iron from the aluminum so that subsequent aluminum precipitation and purification from an acid leach solution is less difficult; and (4) it simplifies the waste disposal system, for iron oxide is relatively unleachable by groundwaters.

The metal concentrate can be treated with ammonia and ammonium carbonate in closed vessels at atmospheric pressure (Forward 1955). Iron remains insoluble as the hydrous oxide, while the trace metals dissolve in the leach solution as complex amines. They are recovered as relatively

pure compounds (basic salts) by boiling so that the NH_3 and CO_2 can be recycled. Also, the leach solutions after boiling and filtration are substantially free of metals, NH_3 , and CO_2 , so they can be discarded, thus facilitating the control of the water balance in the leaching circuit. If uranium and molybdenum dissolve in these alkaline leach solutions, they can be separated from the trace metals by extraction with a tertiary amine, Alamine-336, from a slightly acidified sulfate solution (pH 1.5). The major portion of the shale, nonmagnetics remaining after magnetic beneficiation, is leached with sulfuric acid and the subsequent processing steps to recover aluminum are essentially the same as described above in the acid leach process.

5.2.3. Process cost considerations

A preliminary discussion of process cost considerations will be presented in the following. The development of costs used for the reference process will be discussed in more detail in Chapter 6.

The major capital costs of the minerals recovery reference process are associated with the leaching step, the aluminum precipitation and calcining, and the sulfuric acid plant. The latter was sized to produce sulfuric acid from all of the sulfur that is liberated in the hydrotreating, hydroretorting, and roasting steps. The most important operating costs are those associated with sulfuric acid production, roasting (energy), and refrigeration (ammonium alum precipitation). All of these costs are based on the recovery of ~80% of the uranium and molybdenum in the shale as well as 25% of the aluminum and iron. In order to recover all of the aluminum and iron, it would be necessary to buy sulfur and increase the size of the sulfuric acid plant by at least a factor of two. We do not believe this would be warranted, based on the recovered value of these elements. The fraction of the trace elements that can be recovered from the amount of acid used for the leaching step, and subsequent precipitation as hydroxides at the tail end of the process, is uncertain at this time. Further research and development data are required to delineate these steps in the process; however, the costs associated with the recovery of the small

amounts (total ~0.1%) of the trace elements in the shale as calcined oxides are relatively minor compared to those mentioned above.

The greatest uncertainties in costs are those associated with handling of the wastes, both solid and liquid. The leached residue, after washing and neutralization with on-site crushed limestone, would be compacted and reinserted into the mined-out area. The cost of removing the salts from the final tailings solution by reverse osmosis is estimated as about \$13 million per year, but the costs associated with packaging these salts into cement-like solids that are relatively unleachable by ground waters are uncertain at this time.

No cost figures were obtained for the alternate process since it was conceived after the cost study was completed for the acid leach process. The cost of the magnetic beneficiation process is not a major one. If subsequent, larger experiments verify its validity, then substantial savings can be made during the following process steps, even though more detailed data will be needed. First, the divalent metals such as cobalt, copper, nickel, manganese, and zinc can be dissolved as complex ammonium salts by a cheap alkaline leach at relatively low temperatures, 150 to 170°F. They are separated from iron by this process and can be removed as metal oxides at low cost. Secondly, the iron is largely removed from the aluminum and remains behind as the insoluble hydrous oxide. Depending on its purity and value, it can either be recovered or sent to waste as a nonleachable solid. Also, since most of the aluminum and a small amount of iron remain with the nonmagnetic portion of the beneficiated shale, more of the sulfuric acid is available for recovering aluminum by the acid leach. The difficulties and costs associated with its subsequent precipitation as the ammonium alum can be weighed against its product value as recovered alumina. The costs of handling the waste solids and liquids from this process are expected to be lower than those for the acid process discussed previously.

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6. ECONOMIC ASSESSMENT

The objective of this economic analysis is to determine whether the development of the Chattanooga shales has the potential to be competitive and if so, under what conditions. The main questions addressed were: Does Chattanooga shale look good enough economically to justify additional R and D? and Out of the potential product slate, which products add to the profitability and which subtract?

Four modes of product recovery were examined. In the first mode, oil is recovered (oil-only recovery stage) along with some by-product sulfur and ammonia. In the second mode, uranium and molybdenum are also recovered but the sulfur and ammonia produced previously are now used in the extraction process. In the third mode, about 25% of the available aluminum is also recovered. In the fourth (final recovery) mode, additional molybdenum and aluminum are extracted as well as a mix of other by-product metals (as oxides). Equivalent unit product (oil) prices and return on investment (ROI) were estimated for reference cost and financial parameters for each mode of product recovery. The sensitivity of the ROI and unit cost to variations in parameters were also investigated.

6.1 Methodology

The basic methodology used in the economic analysis was the discounted cash flow approach. With this method, a unit product price or return on investment is found such that the revenue received from the sale of the products throughout the life of the project will pay all expenses, taxes, and returns on outstanding capital investment and will pay back the investment by the end of the project life.

A revision of the ACFAC (Delene, J. G. 1980) computer code was used to do the economic analysis. The code was modified to fit the needs of the Chattanooga shale assessment. ACFAC in its original form was limited to calculating levelized product price and also did not account for inflation explicitly. In the revised code, inflation is accounted for explicitly and the return on investment can be found for a given set of product

prices. In addition, percent depletion has been included with each product treated separately. The minimum tax on tax preference items (depletion and accelerated depreciation) has also been accounted for as has the treatment of energy tax credits in addition to the investment tax credit.

The economic analysis methodology produces results presented in two ways. Alternately the implied rate of return on total capital investment or an equivalent price for oil is calculated. The equivalent price obtained by the second method is a so-called levelized price.

The implied rate of return on investment (ROI) calculated by the first method is that rate of return which causes the sum of the cash flows, discounted at that rate to be zero:

$$\sum_{\substack{\text{Project} \\ \text{life}}} \frac{(\text{Cash flow})_n}{(1 + d)^n} = 0 .$$

The discount rate d is the project ROI. The use of the ROI as a figure of merit implies knowledge of all the costs and revenues involved in the project. The analysis uses projected market prices for all of the products including oil.

In the alternate approach, all costs and revenues are assumed known except for oil. An equivalent levelized cost is calculated for the oil based on the other costs and revenues and the minimum acceptable return on investment. A nominal or a constant dollar levelized price may be obtained. The more common nominal dollar levelized price is an equivalent price which remains constant over the project life. Since inflation occurs during this period, the buying power of the dollar will change, thus this levelized price is in dollars of no single year's buying power.

Alternately a constant dollar levelized price may be found. This is an equivalent price in dollars of a given reference year's purchasing power. The price in any given year is assumed to vary with the rate of inflation, thus for a constant inflation rate i ,

$$P_n = \bar{P}_0 (1 + i)^m$$

where:

P_0 = price in the reference years dollars (1980),

P_n = price in year n dollars, and

m = number of years between year n and reference year 0.

The constant and current dollar levelized costs are related in that the present value to the beginning of the project of the revenues produced by each set of prices are identical, thus,

$$\sum_{\text{Project life}} \frac{\bar{P} \cdot S_n}{(1 + d)^n} = \sum_{\text{Project life}} \frac{P_0 (1 + i)^m}{(1 + d)^n} S_n$$

where:

S_n = sales in year n,

d = discount rate (average cost of money), and

\bar{P} = nominal dollar levelized price.

An example is shown in Fig. 6.1. If the levelized price for oil in 1980 dollars is \$35/bbl, the equivalent, nominal dollar levelized price for a 20 year project starting in 1985 is \$70.90/bbl if the inflation rate is 6% and the discount rate is 15%. Note that the constant dollar price implies a mid-1985 oil price of \$46.80/bbl and a 2005 price of \$150.20/bbl in those year's dollars.

The advantage of constant dollar prices is that inflation is effectively removed from the results. These prices then can be related to current conditions. Except where noted, the results of the analysis given here are expressed in dollars of constant purchasing power.

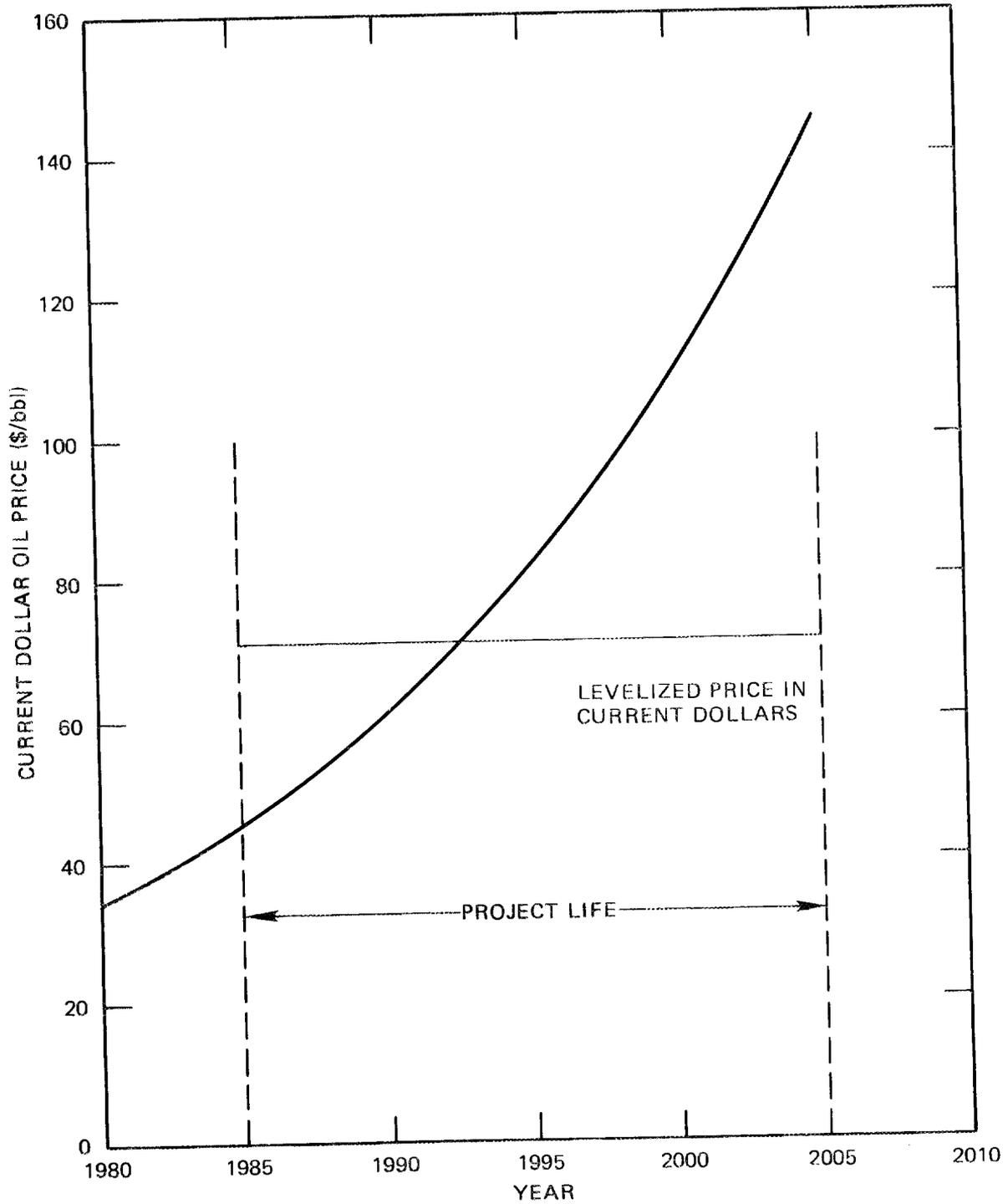


Fig. 6.1. Current dollar and 20-year levelized price of oil that is priced at \$35/bbl in constant 1980 dollars.

6.2 Economic Ground Rules

A tabulation of the ground rules used in the economic analysis is given in Table 6.1. The start of operation is taken as 1985 with a 20 year project life. It is assumed that the average inflation rate through 2005 as measured by the GNP deflator will be 6%/year. This is lower than recent experience and implies a return to a somewhat more stable economy with no sudden step changes in the price of oil as occurred during the 1970s.

A value of 18% was selected for the reference return on equity. This return implies a real return of about 12% after removing inflation. A tabulation of typical returns experienced in industry, as compiled by Forbes' magazine (1980), is given in Table 6.2. These values include the inflation expectation and cover the late 1970s, a period of rising inflation in which the average inflation rate (as measured by the GNP deflator) was over 7%/year. The 18% rate on equity selected as reference is higher than these medians but is consistent with all but 'other oil and gas' if compared to the best half of the companies listed in Forbes. This higher profitability was selected as reference for the analysis since business generally seeks to equal or better their overall performance when selecting new ventures. In addition, a range of equity returns of from 15 to 25% was considered.

The debt-to-equity ratio for companies listed for the industries shown in Table 6.2 range from 0 to 1.0. A reference ratio of 0.5 (1/2) was chosen for the analysis. In addition, a range of debt-to-equity ratios of 0 to 3 was considered. The 0 ratio (corresponding to no debt) was selected since many companies evaluate new projects as if they were 100% equity financed. The debt to equity ratio of three (25% equity financed) is the same as reported for a western shale oil project (Wall Street Jour. 1980b) where the debt portion is guaranteed by the U.S. government.

The 6% state income tax is the effective rate in Tennessee.

In addition to straight line (SL) depreciation over a 16 year tax life, percent depletion is also taken. The applicable percentages are given in Table 6.3. This is deductible from taxable income to a maximum

Table 6.1. Economic ground rules

	Reference	Alternate
Start of operation, year	1985	
Life of project, years	20	
Inflation rate, %/year	6	
Return on equity, %	18	15-25
Interest on debt, %	9	
Debt to equity	0.5	0-3
Federal income tax rate, %	46	
State income tax rate, %	6	
Cost of money during construction, %	10	
Depreciation method	SL	
Tax life	16	
Depletion method	Percent	
Minimum tax on preference income, %	15	
Property tax rate, %	1.0	
Insurance rate, %	0.5	
Investment tax credit (TC), %	10	
Fraction of capital applicable for ITC	0.8	
Maximum fraction of tax liability offset by ITC	0.9	
Tax loss carry forward, years	7	
Energy credit on applicable investments, %	10	
Working capital	Three months operating costs	

Table 6.2. Industry performance statistics^a

Industry	Five-year average return on equity, %	
	Industry median	Best half ^b median
Diversified metals	11.3	17.4
Chemical	15.1	19.4
International oils	15.3	18.3
Other oil and gas	17.0	26.5

^aSource: Forbes, Volume 125, Number 1, January 8, 1980.

^bMedian return based on best half of companies listed.

Table 6.3. Depletion percentages

Product	Percent ^a
Uranium	22
Oil	15
Sulfur	22
Other minerals	14

^aThe percentage of gross income allowable as a deduction when computing federal income taxes.

of 50% of the taxable income from the property figured without the deduction for depletion. Percent depletion is deductible for federal tax purposes but not for state income tax.

The cost of money used during construction is capitalized at a 10%/year rate.

In addition to the normal federal income tax, an additional tax must be paid on tax preference items. These items include excess depreciation (over straight line rate) and excess depletion (over adjusted basis of property). A 15% tax is imposed on the value of these items in excess of the regular tax liability or \$10,000, whichever is greater.

The ground rules assume that 80% of the total investment is applicable for the 10% investment tax credit. This credit is applied when the investment is put in service. The assumption is also made that the venture is an independent corporation so that losses, and credits in excess of taxes, cannot be written off against other income but must be carried forward until used or lost. The investment tax credit is limited to 90% of tax liability as currently specified in the tax law for 1982 or later.

Shale oil equipment is eligible for business energy credit. This credit, currently 10%, was applied to the retort equipment only. The energy tax credit is limited to 100% of tax liability.

Investment tax credits not used in the year incurred are carried forward for a maximum of seven years. Those credits not used in this period are lost.

The amount of money needed for day-to-day operation (working capital) was taken to be equal to three months operating and maintenance costs.

6.3 Capital Investment and Operating Costs

6.3.1 Mining

Mining cost estimates are derived from those used by Mountain States Research and Development in their Chattanooga shale assessment (Mountain States 1978). The costs in the Mountain States Report are based on estimates made by Cleveland-Cliffs Iron Company for underground mining of the shale. Mining costs are in December 1977 dollars. The total direct

capital investment requirement for mining was given as $\$301 \times 10^6$ for a 100,000 ton/d (tpd), 350 d/year operation (35×10^6 tons/year). Of this, $\$117.98 \times 10^6$ was preproduction capital investment and the remaining $\$183.02 \times 10^6$ was deferred capital, being paid out during the 20 year life of the mine. In addition, a 20% contingency was assumed. The operating and maintenance costs were given as $\$2.336/\text{ton}$ plus an additional 10% for general and administration costs.

The Mountain States costs were escalated to mid-1980 dollars (June/July) and scaled to 33×10^6 tons/year throughout. Capital investment costs were escalated using the Bureau of Labor's Statistics Producers Price Index for materials and components for construction. This produces a cost factor of 1.28. A logarithmic size scale factor of 0.8 was used based on underground coal mining costs (Katell 1978). This results in a cost factor of 0.954.

A summary of the resulting mining investment costs is shown in Table 6.4. The preproduction capital investment of $\$172.9 \times 10^6$ is treated in the economic analysis as depreciable capital. The same fractional four year cash flow is assumed as used in the Mountain States Report. The deferred capital investment is assumed to be paid out in 20 equal annual installments of $\$13.4 \times 10^6$. These payments are treated as operating costs in the economic assessment.

The Mountain States estimates for operating and maintenance costs were scaled to mid-1980 dollars using the Bureau of Labor Statistics hourly earnings index for mining. This escalation multiplier is 1.30. Based on an annual throughput of 33×10^6 tons, the operating and maintenance cost is $\$110.2 \times 10^6$ ($2.336 \times 1.1 \times 1.30 \times 33 \times 10^6$). In addition, deferred capital costs add $\$13.4 \times 10^6$. The resulting annual operating cost for mining used in the analysis is $\$123.6 \times 10^6$.

6.3.2 Waste treatment and disposal

The waste treatment and disposal costs consist of all costs necessary to treat mining and process wastes and to dispose of them in an environmentally acceptable manner. There is a large uncertainty as to the process requirements for environmentally acceptable disposal and the costs

Table 6.4. Mining cost summary
(1980 dollars)

	\$10 ⁶
<u>Investment costs</u>	
Preproduction capital	172.9
Deferred capital ^a	268.2
Total capital	441.1
<u>Operating costs</u>	
Operating and maintenance	110.2
Annual deferred capital ^a	13.4
Total annual costs	123.6

^aDeferred capital is treated as an operating cost in economic assessment.

thereof. All recovery options include a cost for solid waste disposal. In addition, the oil only recovery option includes a final high temperature residue treatment step (roasting) to reduce the residue to an acceptable form. The options in which by-product minerals and/or uranium are recovered, involve acid leach so that tailings treatment and disposal is needed for those options.

Three sources of detailed cost information are considered. The first (from a paper Earnest, H. W. et al. 1977) is for waste disposal from a 50,000 bbl/d western shale oil operation. Although these costs are for the same size project as assessed here, the costs are in 1977 dollars. The second source of detailed costs was a National Academy of Sciences (NAS) (1975) committee report on Disposal of Wastes from Coal Mining. From the point of view of this shale oil assessment, these costs suffer from several drawbacks. The NAS costs are for coal operation and not oil shale. These costs are also for substantially smaller operations than the shale oil recovery project. In addition, the costs are in 1975 dollars and contain some costs (such as crushing) which are contained in other parts of the oil shale cost estimate.

A third source of cost information is the Mountain States Report. Estimates are given for solid waste disposal (backfilling) and for the cost of tailings treatment. Backfilling costs are given in December 1977 dollars* and tailings treatment in May 1978 dollars.

The Earnest et al. costs were escalated to mid-1980 dollars using the producer's price index for materials and components for construction for the capital investment and the hourly earnings index for mining for the operating costs. The results are shown in Table 6.5 for five cases of underground disposal and one for surface disposal. The operating costs are based on 33×10^6 tons/year mined.

The NAS capital cost estimates were escalated to 1980 dollars, again using producer's price index information (a factor of 1.52), and scaled for size using a logarithmic scale factor of 0.80. This scale factor was derived based on underground coal mining costs (Katell 1978). The costs

*Mining and backfilling costs are specified as both December 1977 and May 1978 dollars in separate places in the Mountain States Report.

Table 6.5. Western shale waste disposal costs
(10⁶ 1980 dollars)

Transport-storage ^a	Capital investment	Annual operating
Conveyor-conveyor	26.0	13.4
Conveyor-conveyor with pneumatic	30.4	18.3
Truck-truck	58.0	23.5
Pneumatic-pneumatic	80.5	51.5
Hydraulic-hydraulic	113.6	33.2
- surface ^b	25.2	10.6

^aDenotes first the means of transportation to the disposal site and second the means of putting the material into the disposal location.

^bSurface disposal, transport mechanism undefined.

were scaled to a 60,000 to 80,000 ton/d, 330 d/year disposal rate. The shale residue material in need of disposal depends on the amount of by-products extracted and is assumed to range from 60 to 80% of the original weight of material mined. Results are shown in Tables 6.6 to 6.8 for two cases of pneumatic backfilling and one case each for hydraulic backfilling and surface disposal. It should be noted that costs will vary depending on the mining technique.

The Mountain States Report gives a capital investment of $\$54.6 \times 10^6$ for backfilling and $\$62.4 \times 10^6$ for tailings treatment and disposal. In addition, a 20% contingency is applied. The annual operating cost for backfilling was given as $\$0.484/\text{ton}$ mined. The annual operating cost for tailings varied slightly with product slate but amounted to approximately $\$0.60/\text{ton}$ of material mined. In addition, there is a recurring capital cost for the tailing dam of $5.7 \times 10^6/\text{year}$. An additional 10% general and administrative charge is added to operating costs.

The costs from the Mountain States Report were escalated to mid-1980 dollars and scaled to a 33×10^6 ton/year mining rate. Capital investment costs were escalated using the Materials and Components Construction Index. Operating costs for backfilling were escalated using the hourly earnings index for mining, and the operating cost for tailings was escalated using the producer's price index for industrial commodities. Results are shown in Table 6.9. The tailings dam is treated as an operating cost in the economic analysis.

The costs for waste disposal given in Tables 6.5 through 6.9 differ widely depending on the source of information and the method of disposal. The disposal method needs more study but will probably be pneumatic disposal with conveyor or pneumatic transport and storage.

The reference costs for solid waste disposal used in this study were $\$70 \times 10^6$ for capital investment and $\$35 \times 10^6$ for annual operating cost with a range of uncertainty of $\pm 50\%$. The reference costs for tailings treatment and disposal used in the analysis for the oil + U + Mo mode and the oil + U + Mo + Al mode were those derived from the Mountain States report with the tailings dam investment treated as an operating cost. The tailings disposal for the final recovery mode is speculative since this

Table 6.6. Estimates of the cost of coal mine waste disposal
by pneumatic backfilling behind long wall face^a
(\$10³)

	592,250 ^b typ waste		843,180 ^c typ waste	
	Capital	Operating	Capital	Operating
Surface transport		364.0		498.8
Storage and handling				
At plant	53.5	43.6	53.5	19.9
At site	265.0	88.5	423.0	158.5
Borehole and borehole site		70.0		140.0
Stowing system	711.0	767.0	1,421.3	1,443.0
Disposal of fines	500.0	6.1	500.0	7.1
Totals (1975 dollars)	1,529.5	1,339.2	2,397.8	2,267.3
Scale to 1980 dollars and 19.8 × 10 ⁶ typ waste	38,500	38,200	45,500	48,300
26.4 × 10 ⁶ typ waste	48,500	48,500	57,300	61,300

^a Estimates based on NAS, 1975.

^b Backfilling behind a longwall face where waste produced by entire mine can be accommodated in a single mined-out longwall panel.

^c Backfilling behind two longwall faces where amount of waste produced by mine exceeds the capacity of a single longwall panel.

Table 6.7. Estimate of the cost of coal mine waste disposal by hydraulic backfilling^a
 (\$10³)

	690 tpy waste disposal	
	Capital	Operating costs
Surface transportation		448.5
Borehole and site		285.2 ^b
Stowing unit and surface water supply	275.0	331.5 ^b
Underground pumping and recirculation	192.0	86.0 ^b
Underground storage site		67.4 ^b
Totals (1975 dollars)	467.0	1,218.6
Scale to 1980 dollars and:		
19.8 × 10 ⁶ tpy waste	10,400	30,600
26.4 × 10 ⁶ tpy waste	13,100	38,900

^aEstimates based on NAS, 1975.

^bContains certain annual recurring capital costs such as bore holes.

Table 6.8. Cost estimate for surface disposal
of coal mine wastes^a
(\$10³)

	690,000 tpy waste disposal	
	Capital	Operating
Land acquisition	250	
Disposal system	708.9	267.7
Reclamation		35.0
Disposal of fines	500.0	6.8
Totals (1975 dollars)	1,458.9	309.5
Scale to 1980 dollars and		
19.8 × 10 ⁶ tpy waste	32,500	7,780
26.3 × 10 ⁶ tpy waste	40,900	9,880

^aEstimates based on NAS. 1975.

Table 6.9. Waste disposal costs^a
(10⁶ 1980 dollars)

	Capital investment	Operating and maintenance
Backfilling	80.0	22.8
Tailings treatment	86.1	28.7
Tailings dam		7.9

^aEstimates derived from costs in Mountain States report (1978).

mode uses about three times as much sulfuric acid as the other modes. The costs here were assumed to be approximately double those for the previous extraction modes. The oil only recovery mode involves a final roasting step. Roasting costs were estimated by UCND engineering (Cook, K. O. 1981) as part of the cost estimate for uranium, molybdenum, and aluminum extraction. Capital costs here are $\$25 \times 10^6$ with an operating and maintenance cost of $\$15 \times 10^6$ /year.

6.3.3 Oil recovery

The capital investment cost of oil recovery by the hydroretort process is based upon flowsheet and mass balance data that were derived in Chapter 5 and are presented in Fig. 5.1 and Table 5.5. The cost estimates were derived in mid-1980 dollars from published estimates of similar processes and equipment. The total capital investment cost was estimated as \$1.69 billion (Table 6.10). Annual operating and maintenance costs were estimated as \$133 million (Table 6.11).

Shale storage and preparation - The plant was designed to receive 100,000 tons/d of shale. After grinding and sizing about 90,000 tons/d is sent to the process. About 10% of the shale is rejected as being too fine to use. The costs for preparation were estimated from two general sources. The first was recent estimates for retorting western shale (IGT 1980 and USBM 1975) and the second from commercial experience in handling coal (EPA 1977 and Holmes 1977).

Shale feed and discharge system - The shale feed and discharge system is one of the critical areas needing research and development and one of the least best known of the cost components. The estimates presented here are higher than those made by others for shale processing. For costing purposes the commercial Petrocarb system is used. This system is commercially available and used in the cost estimate of a number of coal systems. Costs from estimates of coal feeding systems for pressurized fluidized bed systems were considered as the baseline (EPA 1977).

While these costs are higher than other shale estimates, they in turn are considered to be somewhat optimistic. The base line data are for coal fed against 150 psig of air, while the Hytort system requires feed against

Table 6.10. Capital investment cost
for oil recovery plant
(10⁶ 1980 \$)

Shale storage and preparation	100.
Shale feed and discharge	75.
Hydroretorts	50.
Acid gas removal	40.
Sulfur recovery	70.
Hydrogen and recycle preheat	135.
Compressors	40.
Oxygen plant	30.
Hydrogen plant	190.
Hydrotreator	120.
Steam generation	50.
Electric distribution	40.
Water supply and treatment	60.
Particulate control	5.
Subtotal	1,110.
Offsite	200.
Contingency	300.
Engineering and fee	180.
Total	1,690.

Table 6.11. Operating and
maintenance costs for
oil recovery plant
(10⁶ 1980 \$/year)

Labor	15.
Materials	25.
Power	45.
Maintenance	48.
Total	<hr/> 133. <hr/>

400 to 500 psig of hydrogen. Whether there exists equipment that can reliably feed in this environment is questionable; IGT has developed a patented feed system but its reliability is unknown.

Hydroretorts - The hydroretorts are considered to be cylindrical high temperature pressure vessels. The residence time of the shale requires that the reactors have capacity of at least 200,000 ft³. For the purpose of this assessment, six reactors, 90 ft high and 22 ft in diameter were chosen. The cost for these reactors was taken from a number of sources (EPA 1977 and Holmes 1977) and normalized.

Acid gas removal and sulfur recovery - The Selexol process was selected as the preferred system for removing the hydrogen sulfide and some of the carbon dioxide. The Claus process and the SCOT process were assumed for sulfur recovery and tail gas cleaning, respectively. The cost of these systems was estimated through the use of the reported data of Edwards (1979) and Singh (1980). Because of the high sulfur content of the shale and the extremely large flow rate of the recycle, the cost of these systems is large.

Cryogenic separation - Cryogenic separation is needed to separate the hydrogen from the products and from the feedstock to the steam reformer. This component could be eliminated by changing the overall system design at an increased cost of other components. IGT took another approach in their evaluation of western shale retorting (IGT 1980b). The cost for this system was estimated from several sources (IGT 1980b, Holmes 1977, and Vyas 1981). The accuracy of this cost and the need for the component at all is one of the larger uncertainties in the analysis.

Hydrogen production - The conversion of light hydrocarbons to hydrogen is commercial technology. The hydrogen production step consists of steam reformers, CO-H₂ shift reactors and a methanation step. The hydrogen is about 96% of the exit stream with the remainder being methane. Hydrogen is produced for make-up to the recycle stream and for hydrotreating the shale oil.

Shale oil hydrotreating - The shale oil is upgraded from the as-retorted state to a fairly high quality oil via a hydrotreating process. The purpose of this step is to remove much of the nitrogen and sulfur in the oil. Hydrogen is added in the process. The cost of hydrotreating is

variable depending in large part on the severity of the treatment. Costs were estimated from the data of Eccles (1981).

Utilities - The costs for utilities including those for steam generation, cooling water, and water treatment were based upon design studies of a project for retorting of western shale (IGT 1980b). The cost of the air separation plant for the production of oxygen was estimated from the data of Wham et al. (1981) and Vyas (1981).

Indirect costs - The indirect costs were estimated from various estimates of similar projects. The contingency was assumed to be 30% which represents the level of confidence in the cost estimates and the technical uncertainty of the process.

Operating and maintenance costs - The estimate for operating and maintenance costs was accomplished in two ways. First, the manpower requirements (600 operating staff and 500 maintenance staff) were estimated using guidelines established in other studies (IGT 1980b and Holmes 1977) and then using \$25,000/man-year to estimate the labor charges. Electric power consumption was estimated to be 142 MW at a cost of \$0.040/kWh. The overall costs were checked by comparing them as a percentage of the total capital with other published estimates.

6.3.4 Uranium, molybdenum and aluminum recovery

Estimates by UCND Engineering (Cook 1981) indicate that the capital investment cost for recovery of 80% of the uranium and molybdenum and a subsequent partial (25%) aluminum recovery step is in the range of \$400 to \$600 million. Based on this cost range, the reference capital investment cost used in this analysis is $\$500 \times 10^6$. An approximate breakdown of this cost is given in Table 6.12. Of this total, $\$25 \times 10^6$ is for roasting of the hydroretort residue, $\$400 \times 10^6$ is for the uranium and molybdenum recovery and $\$75 \times 10^6$ is for the aluminum recovery. Operating and maintenance costs are $\$15 \times 10^6$ for roasting, $\$75 \times 10^6$ for uranium and molybdenum recovery, and $\$60 \times 10^6$ for aluminum recovery as shown in Table 6.13.

Table 6.12. Capital investment costs
for metals recovery(10⁶ 1980 \$)

	U + Mo + Al ^b recovery	Final step recovery ^a
Roasters	25	
Sulfuric acid plant	55	93
Leaching	200	330
Solvent extraction	40	69
Stripping	10	12
U + Mo extraction	10	
Process electricity	20	18
Process instrumentation	42	35
Utilities	23	20
Aluminum extraction	75	133
Total	500	710

^aThese investments are in addition to those for the U + Mo + Al recovery steps..

^bThe Aluminum recovery is optional.

Table 6.13. Operating and maintenance costs
for metals recovery
(\$10⁶, 1980 \$/year)

	Roasting	U + Mo recovery	First Al step	Final recovery step
Chemicals and supplies	0	11	0	170 ^a
Energy and fuel	8	0	40	80
Payroll	3	4	0 ^b	5
Maintenance	4	60	10	105
Refrigeration	0	0	10	20
Total	15	75	60	380
Total through step	15	90	150	530

^aInclude purchase of additional sulfur for sulfuric acid manufacture.

^bNo additional manpower needs for first Al recovery step.

6.3.5 Final metals recovery step

This step includes the recovery of additional molybdenum and aluminum as well as a mixture of trace element metal oxides. The capital investment costs and the operating and maintenance costs for the final step are summarized in the last columns of Tables 6.12 and 6.13. These costs are quite speculative since the processes involved have not been fully defined.

6.3.6 Cost summary

The summary of the reference capital investment costs used in this study for the four operating modes considered is given in Table 6.14. Reference annual operating and maintenance costs are presented in Table 6.15. The construction cash flow schedule is given in Table 6.16.

6.4 Product Prices and Yields

6.4.1 Oil price

The most important commodity extracted from the Chattanooga shale is oil. The price at which this oil can be sold is an important consideration in determining the economic viability of mining and processing the shale. The quality of the oil produced from the hydroretort process is very good and it may require only limited further refining. Even so, the reference price structure used in this analysis is based on crude oil price projections. The behavior of the price of oil in the recent past indicates that attempts at oil price predicting may be foolhardy. However, such a prediction (or range of price projections) is necessary if project economics are to be evaluated.

Figure 6.2 illustrates the behavior of the international price of oil over the last 13 years. This is a plot of the price of Saudi Arabian crude oil, (Oil and Gas Jour. 1980a) f.o.b. Saudi Arabia adjusted by the

Table 6.14. Capital investment cost summary
(10⁶ mid-1980 dollars)

Cost center	Recovery mode			Full recovery
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	
Mining	173	173	173	173
Solid waste disposal	70	70	70	70
Tailings treatment	0	86	86	172
Oil recovery plant	1,690	1,690	1,690	1,690
Roasting	25	25	25	25
U + Mo	0	400	400	400
First aluminum step	0	0	75	75
Final recovery	0	0	0	710
Total (1980 dollars)	1,958	2,444	2,519	3,315
IDC	398	504	521	695
Escalation	353	437	449	585
Initial working capital	115	156	177	324
Total (Jan. 1, 1985)	2,824	3,541	3,666	4,919

Table 6.15. Operating and maintenance cost summary
(10⁶ mid-1980 dollars)

Cost center	Recovery mode			Full recovery
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	
Mining	124	124	124	124
Solid waste disposal	35	35	35	35
Tailings treatment	0	36	36	72
Oil recovery plant	133	133	133	133
Roasting	25	15	15	15
U + Mo recovery	0	75	75	75
First aluminum step	0	0	60	60
Final recovery step	0	0	0	380
Total (1980 dollars)	307	418	478	894

Table 6.16. Cash flow during construction
(fraction of total)

	Time at which money paid relative to startup (years)			
	-3	-2	-1	0
Mining	0.06	0.24	0.25	0.45
Waste disposal	0	0	0.5	0.5
Tailings treatment	0.2	0.4	0.4	0
Oil recovery plant	0.2	0.4	0.4	0
Roasting	0.2	0.4	0.4	0
Metals recovery steps	0.2	0.4	0.4	0

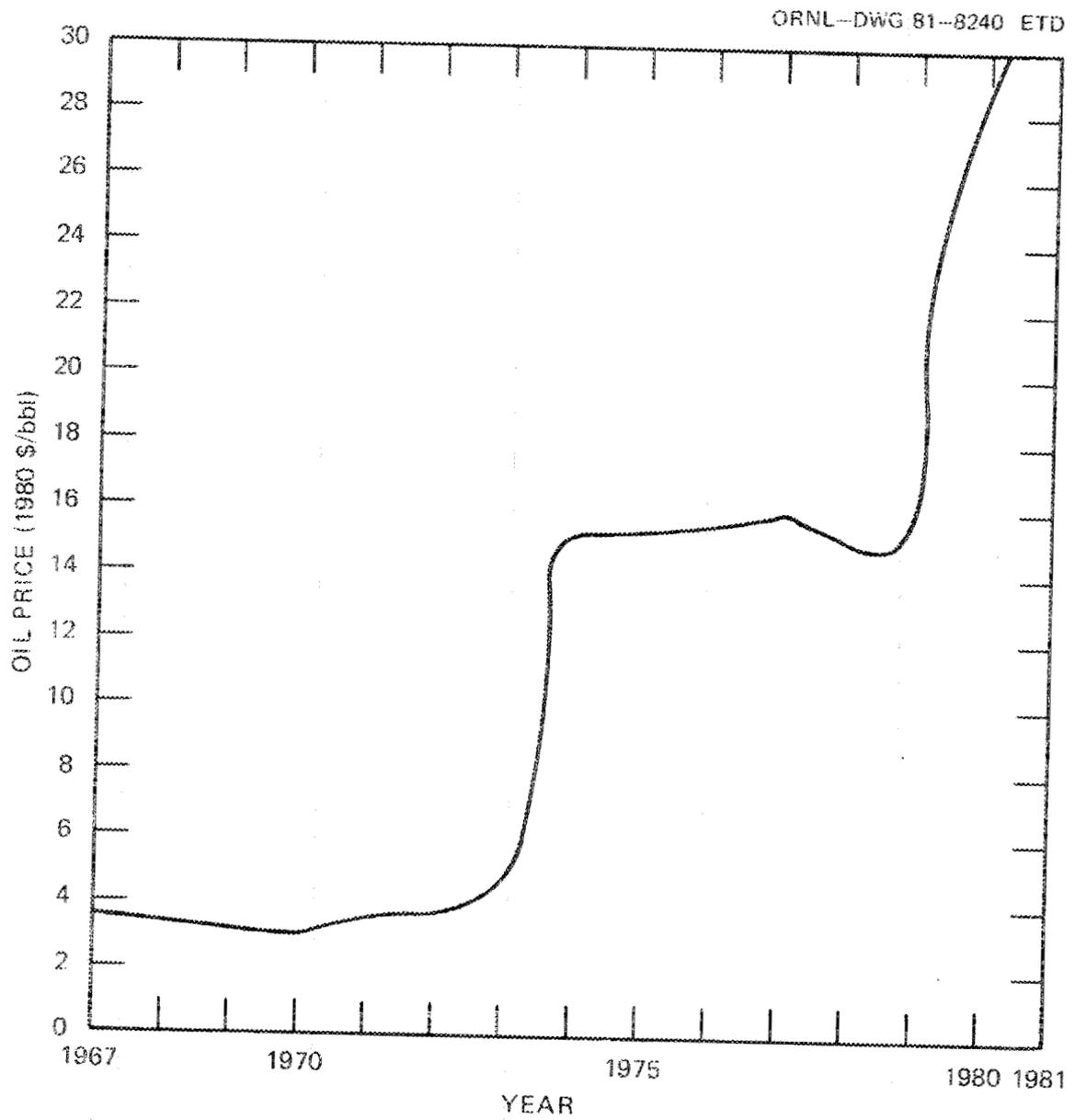


Fig. 6.2. Price of Saudi Arabian crude oil since 1967 (fob Saudi Arabia) in constant 1980 dollars.

U.S. GNP deflator as given in the U.S. Dept. of Commerce Survey of Current Business publication to obtain a price in constant 1980 U.S. dollars. The oil price in constant dollars has increased eightfold from about \$3.60/bbl in 1967 to an expected average of about \$29/bbl in 1980. Oil price increases have been sudden and unpredictable. The 1973 price increase resulted from the Arab-Israeli War and those in 1979 and 1980 resulted from the Iranian Revolution and the subsequent Iranian-Iraqi War.

The official price of Saudi oil represents a minimum oil price. It does not include transportation charges and, in addition, the other OPEC countries are demanding and getting higher prices. In late 1980, the spot price of arab light, the benchmark crude produced by Saudi Arabia oil in the U.S. market, had reached \$39.00 to 39.50 per barrel (The Wall Street Jour. 1980a). Also Saudi Arabia is charging \$35/bbl for some of the oil obtained through increased production. With oil price deregulation, the price of crude oil in the United States is expected to reflect the international market price, particularly the price of Saudi Arabian oil.

The Saudi Arabians have recently proposed that the price of OPEC oil be readjusted on a quarterly basis in line with certain indices (Oil and Gas Jour. 1980b). Although not spelled out exactly, these indices consider:

1. the rate of inflation of export and consumer prices in the Organization for Economic Cooperation and Development (OECD) nations,
2. a compensation for currency fluctuation through a market basket of nine currencies, and
3. a floor price which remains in line with real GNP growth in the OECD states.

This plan was not acted on at the June 1980 OPEC meeting but can serve as a means for projecting future oil prices if the assumptions are made that the current Mideast problems can be resolved and that there are no future gross disruptions as occurred in 1973 and 1979.

The oil prices used in this study are based on the assumption that oil prices will settle out in a range of from \$30 to \$45 per barrel in 1980 dollars plus an escalation rate in future years approximately equal to the real GNP growth in the industrial nations. During the early to mid-1970s the growth in real GNP for the industrial nations (Int. Financial

Statistics 1978) was in the range of <1 to >5%/year with a nonweighted average of close to 3%/year.

The reference price for oil in 1980 dollars chosen for this study is \$35/bbl plus a real growth rate of 3%/year. The low estimate is \$30/bbl + 2%/year and the high estimate is \$45/bbl + 4%/year. This price range is illustrated in Fig. 6.3.

6.4.2 Uranium ore price

One of the most important commodities to be recovered from Chattanooga shale is uranium. At the recent current spot market price of \$30/lb U_3O_8 and 80% recovery, shale containing 65 PPM uranium will yield about \$3.60 in uranium revenue/ton of shale mined.

Historically the price of uranium has exhibited wide fluctuations (NUEXCO 1977). During the late 1960s and early 1970s, its price was at a low of \$6 to \$7/lb of U_3O_8 . It then rose to an average price of nearly \$44/lb in 1978 with some reported prices topping \$50/lb (Nuclear Fuel 1978). Recently the price has been in a decline reaching \$30/lb (The Wall Street Jour. 1980c) in the third quarter of 1980. A plot of the uranium price adjusted to 1980 dollars (using the GNP deflator) is shown in Fig. 6.4. As shown in the figure, the price change between 1973 and 1977 was nearly a factor of five in constant dollars.

The recent uranium price drop reflects a decrease in demand projections brought about by reactor cancellations in response to an enhanced public concern over the safety of nuclear power. How much the price of uranium will fall and to what level it will recover is speculative. A recent report by Colorado Nuclear Corporation (Nuclear Fuel 1980a) predicts a bottom in the \$17 to \$26/lb range with recovery to \$43/lb by 1988. A price decrease to those levels would lead to the closing of some capacity. A recent Nuclear Assurance Corporation (NAC) estimate (Nuclear Fuel 1980b) for a sample of major U.S. production centers arrives at an average production cost of about \$24.40/lb U_3O_8 . If profit is included, the uranium price would have to be in the mid- to upper-30s for a 12.5% return on investment. Also, the average grade of U.S. uranium has been decreasing from an average of about 4.2 lb/ton in 1969 to 2.2 lb/ton 1979 (The Wall

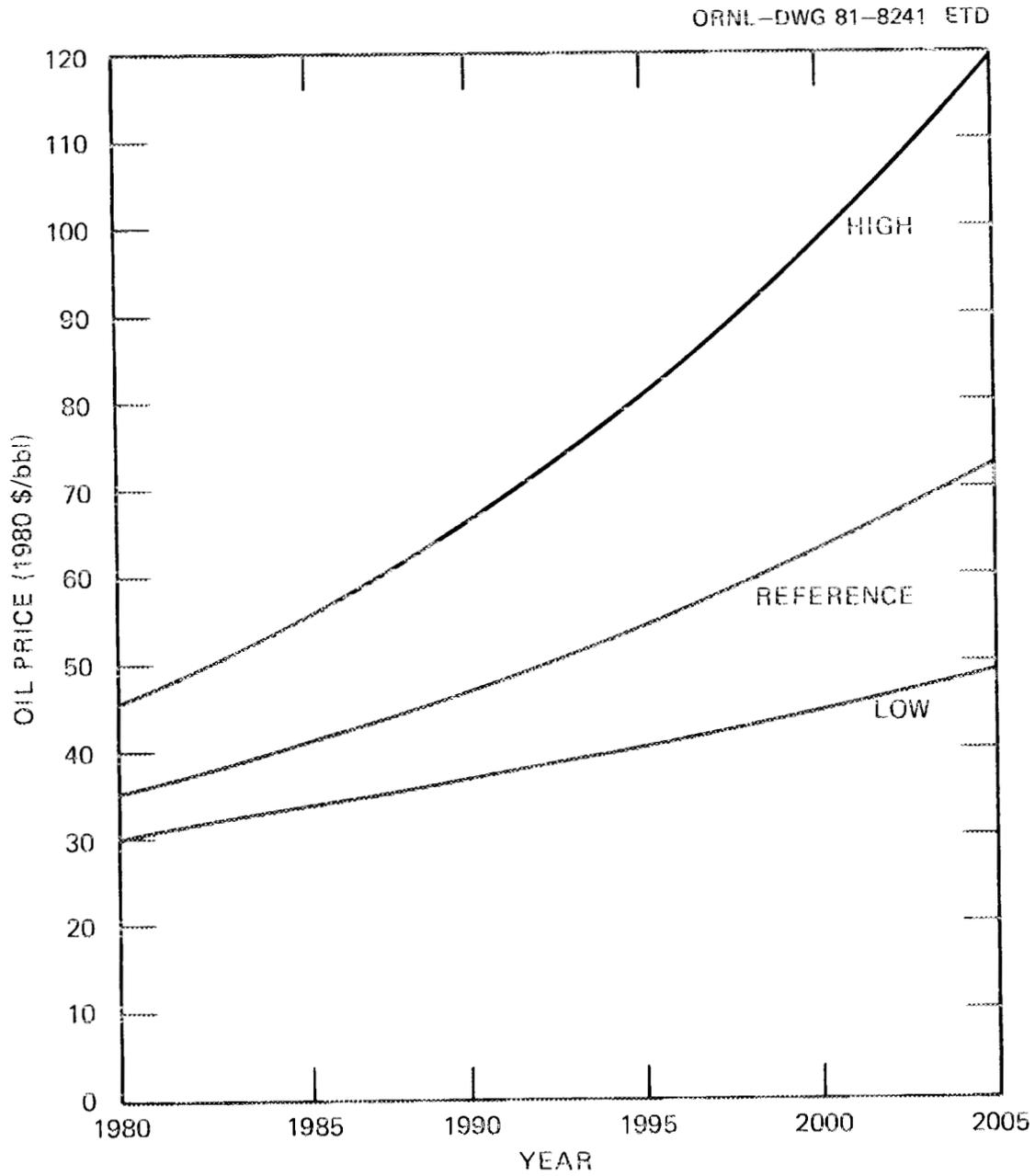


Fig. 6.3. Projected oil price in constant 1980 dollars.

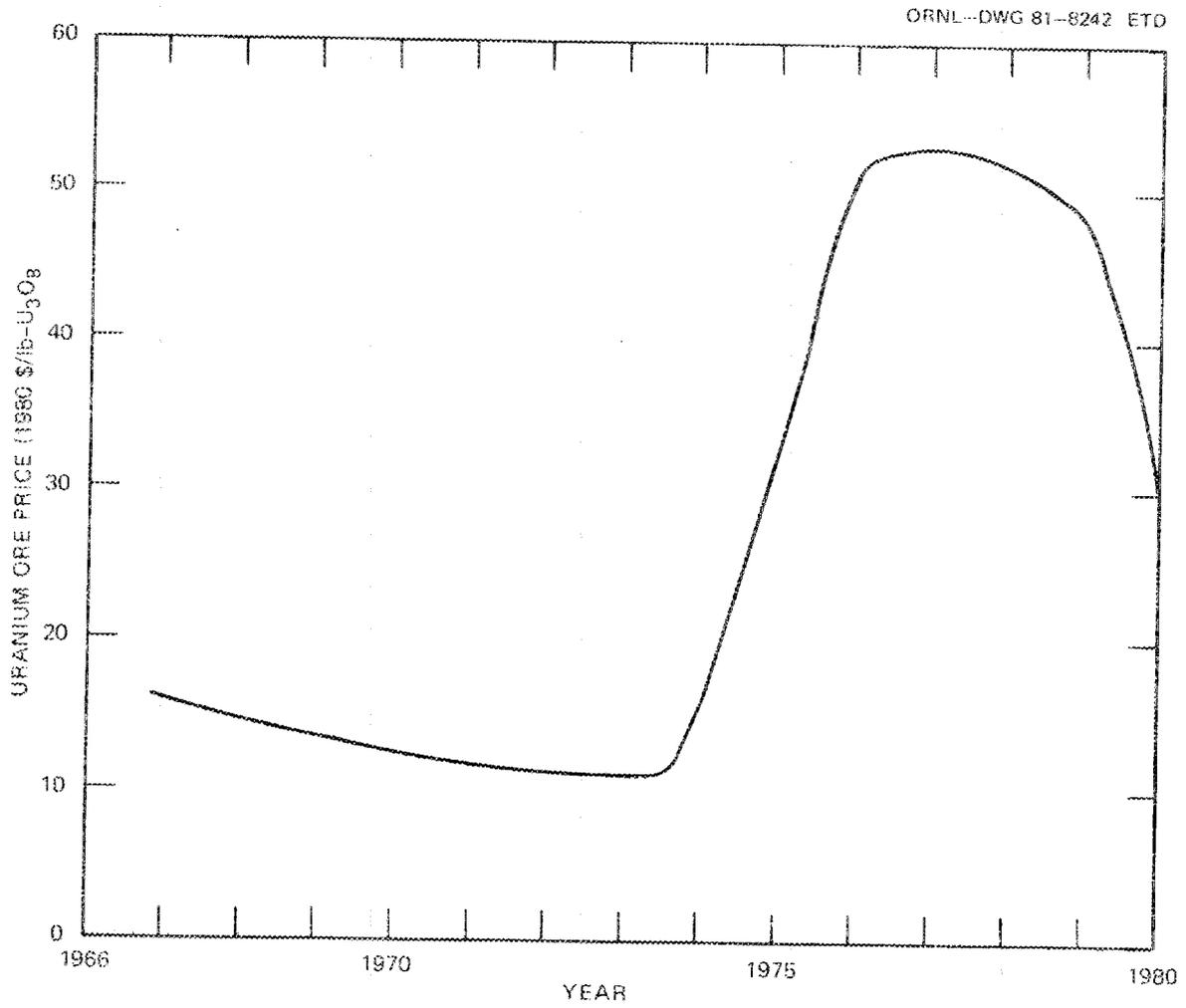


Fig. 6.4. Variation of uranium ore price since 1967 expressed in constant 1980 dollars.

Street Jour, 1980c). Such considerations and the realization that the U.S. needs nuclear power to meet its energy demands at a reasonable price could lead to a recovery in the price levels.

On the negative side is the possibility that the reactor sales will not recover. Also, there is the prospect for increased competition in worldwide uranium sales. Canada and Australia have widespread deposits, some of which are of very high grade. The average grade of Saskatchewan, Canada uranium reserves is about 30 lb/ton (Nuclear Fuel 1979), while those of Australia are 8 lb/ton. Low cost production could lead to price cutting; however, both governments take an active role in uranium sales contracts to assure an optimum return on uranium exports (Nuclear Fuel 1980c).

Uranium price projections are shown in Fig. 6.5. Price projections had been developed for the Nonproliferation Alternative Systems Assessment Program (NASAP) (U.S. DOE 1980 and Spiewak 1980) and for the Energy Economic Data Base (EEDB) (EEDB 1979) program of DOE. The NASAP prices were developed for various demand and supply assumptions while only one estimate is presented for the EEDB. These prices were in 1978 dollars. The prices shown in Fig. 6.5 were adjusted to 1980 dollars using the GNP deflator.

The reference uranium price projection used in the Chattanooga shale economic analysis assumes a 1980 ore price of \$30/lb, with a real escalation rate of 3% above inflation (same as for reference oil). The low estimate assumes a 1980 uranium price of \$25/lb with the price recovering to \$40/lb in the year 2000. The high projection assumes that the price of uranium recovers to the \$40/lb (1980 \$) level by 1985 then continues to escalate to the NASAP-high demand, mid-supply price in 1995. This growth continues until the EEDB price projection is reached. The high projection then approximately follows EEDB reaching a price of \$75/lb in 1980 dollars in 2005.

6.4.3 By-product prices

Prices used in the analysis for process by-products (other than oil and uranium) are given in Table 6.17. The prices of these minerals were assumed to escalate with time at the general rate of inflation (6%/year).

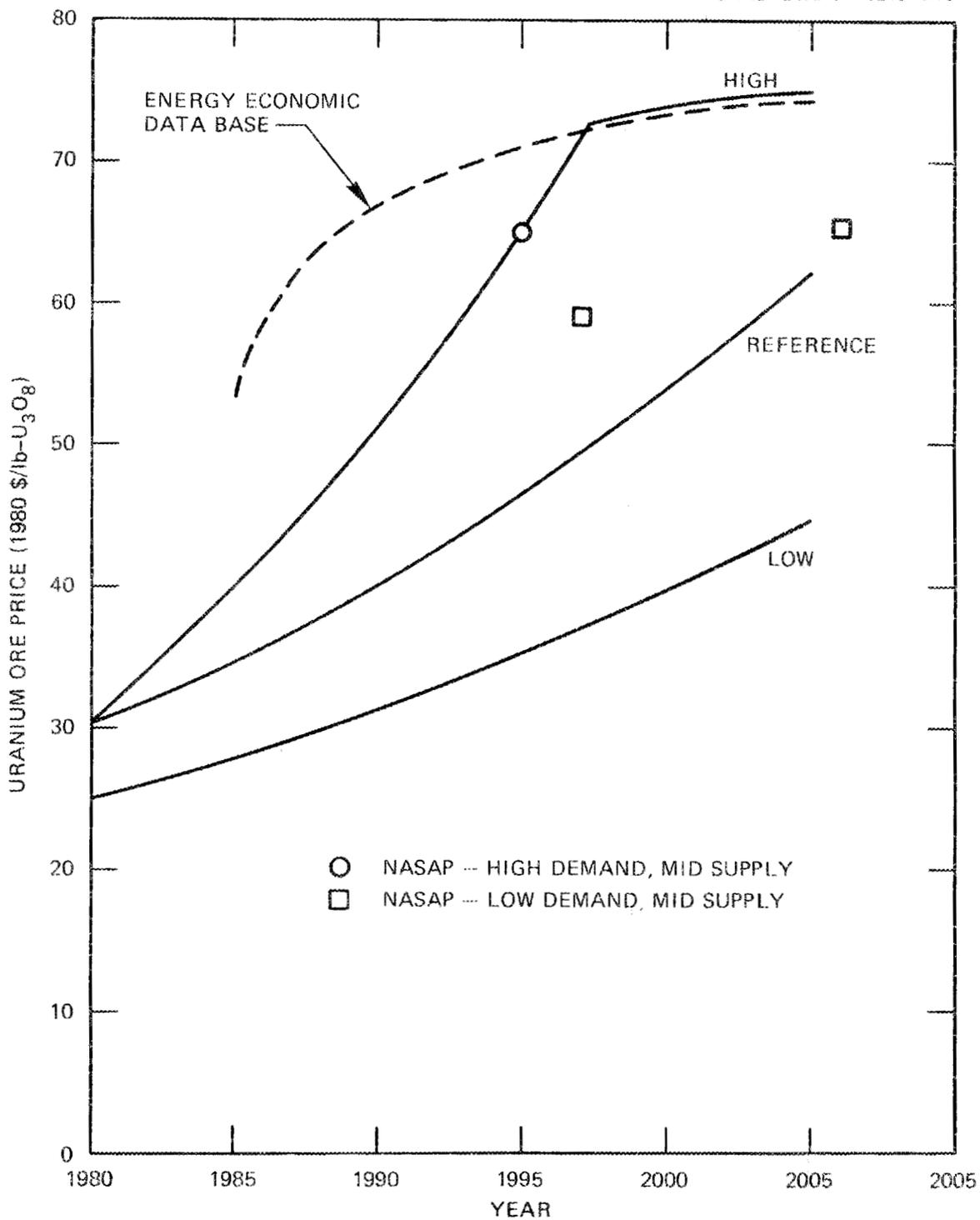


Fig. 6.5. Projected price of uranium ore in constant 1980 dollars.

Table 6.17. By-product prices

Products	Units	Price
S	\$/t	45.
NH ₃	\$/t	155.
MoO ₃	\$/lb	5.50
Al ₂ O ₃	\$/t	200.
Mixed trace metal	\$/lb	1.50 ^a

^aApproximately 1/2 of the value of the metal as oxides.

6.4.4 Product yields

The product yields used in the economic analysis for each mode of operation are given in Table 6.18. These numbers are based on flow sheets given elsewhere in this report.

6.5 Results of Economic Assessment

Two main figures of merit were used to assess the economic viability of the extraction of oil and other commodities from the Chattanooga shales. These are the project return on investment (ROI) and the equivalent cost of the product oil. The methodology used to obtain ROI and oil cost was discussed in Sect. 6.1. The economic analysis was done for each of the four operating modes: oil recovery only; oil, uranium, and molybdenum recovery; oil, uranium, molybdenum, and aluminum recovery; and full recovery. The ROI on the incremental investment at each extraction step was also estimated.

In addition to the computation of the oil cost and the ROI for baseline assumptions, the effect on the results of variations in cost and financial parameters was investigated.

6.5.1 ROI analysis

The project ROI was calculated based on the reference financial and cost assumptions given in Sects. 6.2 and 6.3 and the projections of product prices and yields given in Sect. 6.4. The project Debt to Equity ratio was held at 0.5 with interest on debt of 9%; therefore, as ROI varies, the return on equity also changes.

A summary of the results of the ROI analysis for each operating mode is given in Table 6.19. This table shows the return on investment (ROI) and the percentage of the revenues from the various product sales levelized at the project ROI.

The ROI for the recovery mode in which no uranium or by-product metals are recovered is 23.4%. In this operating mode some sulfur and ammonia are also obtained as by-products. The low oil price projection

Table 6.18. Product slate
(100,000 tons/d of shale)

	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Oil, BOE/d	46,000	46,000	46,000	46,000
Sulfur, t/d	2,500	0	0	0
Ammonia, t/d	350	0	0	0
U ₃ O ₈ , t/d	0	6	6	6
MoO ₃ , t/d	0	30	30	36
Al ₂ O ₃ , t/d	0	0	2,700	8,100
Mixed trace metals, t/d (Co, Cu, Cr, Mn, Ni, Vn, Zn)	0	0	0	100

Table 6.19. Summary of results

	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Return on investment, %	23.4	24.2	26.7	23.0
Return on equity, ^a %	30.6	31.8	35.5	30.0
Revenue source, ^b %				
Oil	93	70	59	43
S + NH ₃	7			
Uranium		16	14	10
Molybdenum		14	12	10
Aluminum			15	31
Trace metals				6

^aFor 67% equity and 33% debt at a 9% interest rate.

^bLevelized using project return on investment as the discount rate.

produces an ROI of 16.9% while the high oil price projection provides an ROI of 32.7%.

In the recovery mode in which oil, uranium, and molybdenum are recovered, the sulfur and ammonia produced are used in the process so are not available as by-product sales. Based on the reference oil and uranium price projections, the ROI for the project is 24.2%. The low projections for both oil and uranium prices result in an ROI of 18.9%, while high projections for both commodities lead to an ROI of 32.6%.

The incremental ROI of going to the uranium extraction step was also calculated. This is the return on the additional investment needed to extract the uranium and molybdenum. This return was estimated to be 27% based on the reference uranium price projection and reference costs. The low and high uranium price schedules produce an incremental ROI range of from 22 to 32%.

The next recovery step involves the recovery of about 25% of the available aluminum. Based on the reference assumptions, the ROI for the project operating in this mode is 26.7%. The low projections for both oil and uranium price result in an ROI of 21.2%, while high projections for both commodities lead to an ROI of 34.5%.

The incremental ROI on the additional investment needed to extract the aluminum is about 90%.

In the final recovery step, additional molybdenum and aluminum are recovered, as well as a mixture of trace element metals, as oxides. The reference project ROI for this operating mode is 23.0%. The low projections for both oil and uranium price result in an ROI of 18.4%, while high projections for both commodities lead to an ROI of 29.5%. The incremental ROI on the final extraction step was estimated to be 8.6% at reference parameters.

6.5.2 Oil cost analysis

The constant, 1980 dollar, levelized cost of oil from the project was also calculated for each operating mode. In this analysis, the return on investment is held constant at the reference value of 15% (return on

equity = 18%, interest on debt = 9%, and debt to equity ratio = 0.5). The cost of oil was calculated assuming all other product prices and costs remain at their reference values. This approach produces a cost for oil which can be directly related to market price or the cost of oil from other processes.

Figure 6.6 shows graphically the levelized cost of oil for the four operating modes. Both the total cost without by-product credits and the value of the credits on a dollars per barrel basis are shown. Table 6.20 gives the contribution of each cost center and by-product credit to the oil price at the reference set of parameters.

The reference cost for oil in the oil only recovery mode is \$35.30/bbl. The recovery of the uranium and molybdenum reduces the net cost of oil to \$29.60/bbl. This cost has in it the sale of uranium at the reference price projection producing a credit equal to \$11.70/bbl of oil. The low and high uranium price projection produces credits of \$9.00 and \$14.80/bbl, respectively.

The addition of the recovery of 25% of the available aluminum reduces the equivalent levelized cost of oil to \$22.60 at the reference cost and price assumptions. Sale of the uranium at the low and high price projections results in oil costs of \$25.30 and \$19.60/bbl, respectively.

In the full recovery mode, the levelized cost of oil is \$26.50/bbl. In this mode, only 43% of the total revenue comes from oil sales.

6.5.3 Sensitivity analysis

The sensitivity of the oil cost and project ROI to variations in various cost parameters and prices was investigated for the oil only and oil + U + Mo + Al recovery modes. Table 6.21 gives the oil cost differential for variations in various parameters from their reference values.

Since various corporate ventures have different debt-to-equity (D/E) ratios, the levelized cost of oil as a function of debt fraction was estimated and is shown in Fig. 6.7 for all three modes of operations. For the oil + U + Mo + Al recovery mode, a venture financed entirely with equity money at an 18% return would have an oil cost of \$30.10/bbl instead of the reference cost of \$22.60/bbl, based on a third of the capitalization from

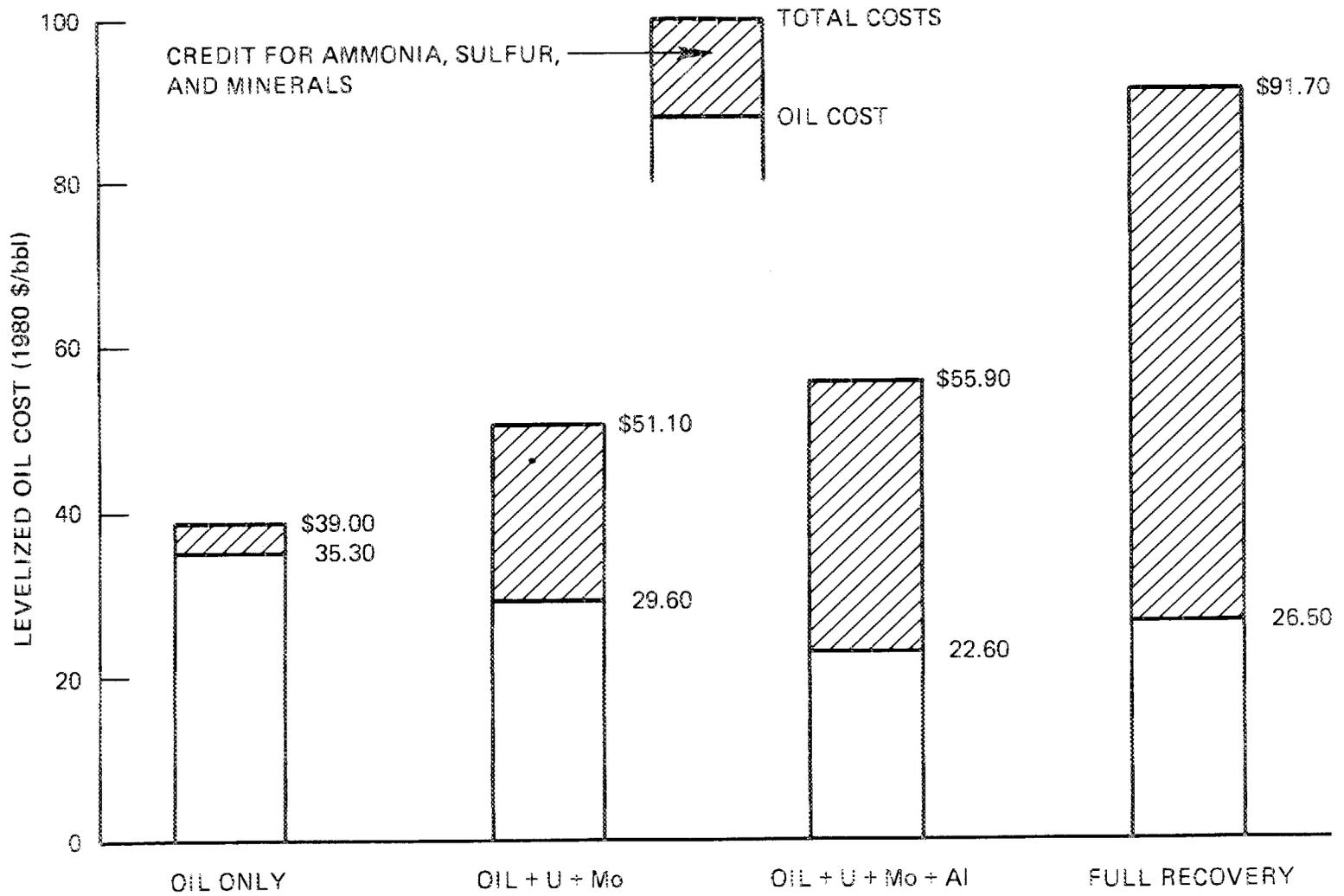


Fig. 6.6. The effect of degree of minerals recovery on the cost of recovering oil from Chattanooga shale.

Table 6.20. Contribution to oil price

Cost center	1980 \$/bbl
Mining	10.10
Waste disposal	3.00
Hydroretort	24.60
Roaster	1.30
Tailings treatment	3.30
U + Mo recovery	10.10
First aluminum step	4.10
Final recovery	35.80
Sulfur credit	2.50
Ammonia credit	1.20
Uranium credit	11.70
Molybdenum credit	9.80 ^a -11.60 ^b
Aluminum credit	11.80 ^a -35.40 ^b
Trace metals credit	6.50

^aOil + U + Mo and Oil + U + Mo + Al recovery modes.

^bFor full recovery mode.

Table 6.21. Oil cost sensitivity

Variation from reference parameters	Oil cost change (1980 \$/bbl)
$\$10 \times 10^6$ operating cost increase	0.69
$\$100 \times 10^6$ investment cost increase	0.92
10% increase in oil yield ^a	
Oil only mode	--3.20
Oil + U + Mo mode	--2.70
Oil + U + Mo + Al mode	--2.05
Full recovery mode	--2.40

^aOil unit cost is approximately inversely proportional to oil yield.

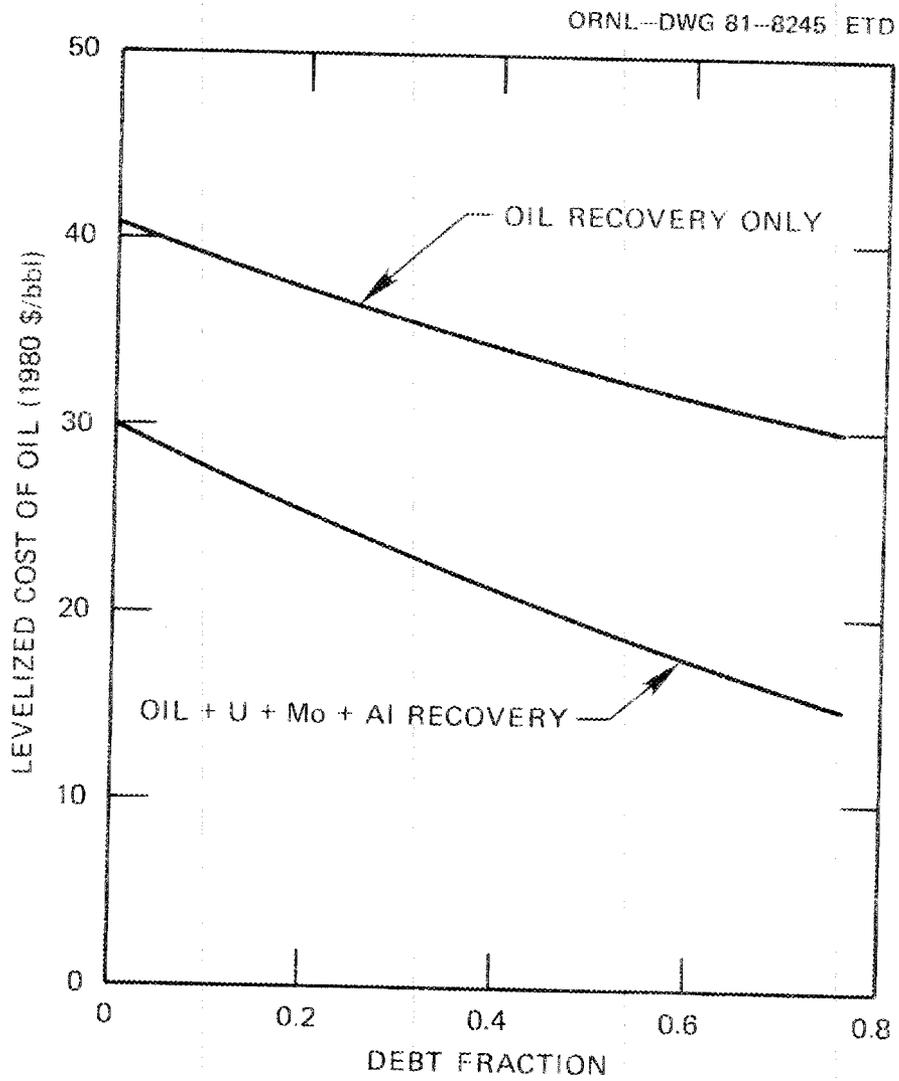


Fig. 6.7. The effect of debt fraction on the cost of oil from Chattanooga shale.

debt at 9%. For 75% debt fraction, which may be the case if loans are guaranteed by the government, the oil cost would be \$15.50/bbl.

The effect of the variations in the required return on equity (ROE) on the cost of oil is shown in Fig. 6.8. For recovery through the first aluminum step, the oil cost for a 15% ROE is \$19.30/bbl. The oil cost is \$31.60/bbl for a 25% ROE.

Figure 6.9 demonstrates that the return on investment is relatively insensitive to the corporate debt fraction. There is a variation of about 2% in the ROI over a range of debt fractions of 0 to 0.75 (D/E = 0 to 3). The effect on the return on equity of variations in the debt fraction is substantial, however, as demonstrated in Fig. 6.10. At the reference parameters, the return on equity (ROE) for the oil only recovery mode is 30.6%. The ROE at 100% equity financing is 22.3% and at 75% financing the ROE is 71.2%.

Figure 6.11 shows the effect of variations in costs (investment and operating) on project ROI. As an example, if the investment and operating costs are 25% greater than the reference values, the project ROI for the oil only recovery case is lowered 5.8% to 17.6%.

The reference oil price used in this study was \$35/bbl (mid-1980 dollars). This price was selected as reflecting the marginal price of crude oil. The oil recovered from the shale by hydrotreating will be of a better quality than crude oil in general and will possibly sell at a premium since for many uses it will not have to be refined further. The sensitivity of the ROI to the oil price is shown in Fig. 6.12. For all four operating modes, the range of increase in the project ROI for each dollar that the shale oil sells at above the \$35 reference price is 0.3 to 0.7%.

The effect on the project ROI of the uncertainty in the real oil price escalation rate is shown in Fig. 6.13. Using the oil + U + Al recovery mode as an example, if the price of oil was to escalate from its mid-1980 value of \$35/bbl at only the rate of inflation (real escalation rate = 0) the project ROI would be 21.3%. On the other hand, if the real oil price escalation rate was 4.5%, the project ROI would be 29.5%.

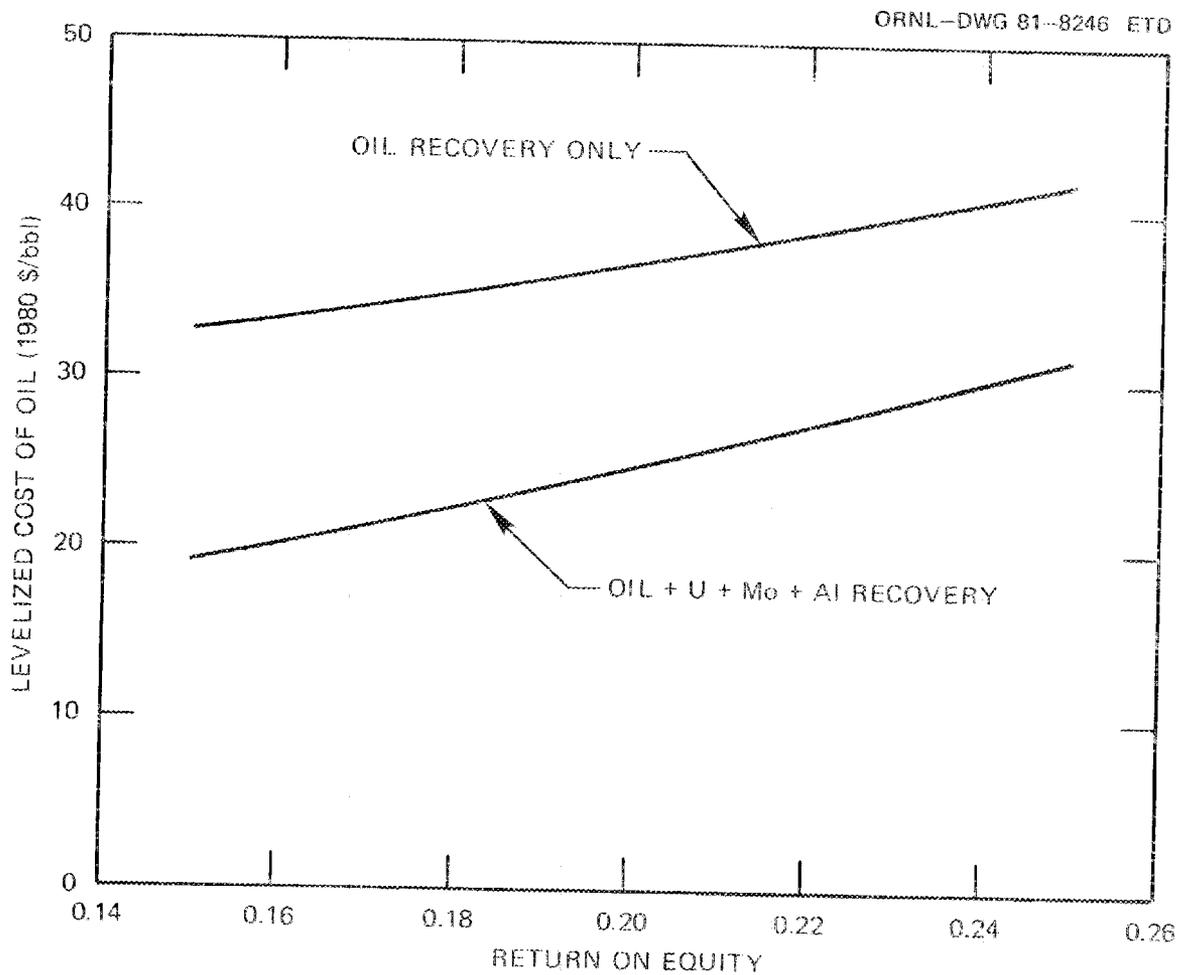


Fig. 6.8. The effect of variations in the required return on equity on the cost of oil from Chattanooga shale.

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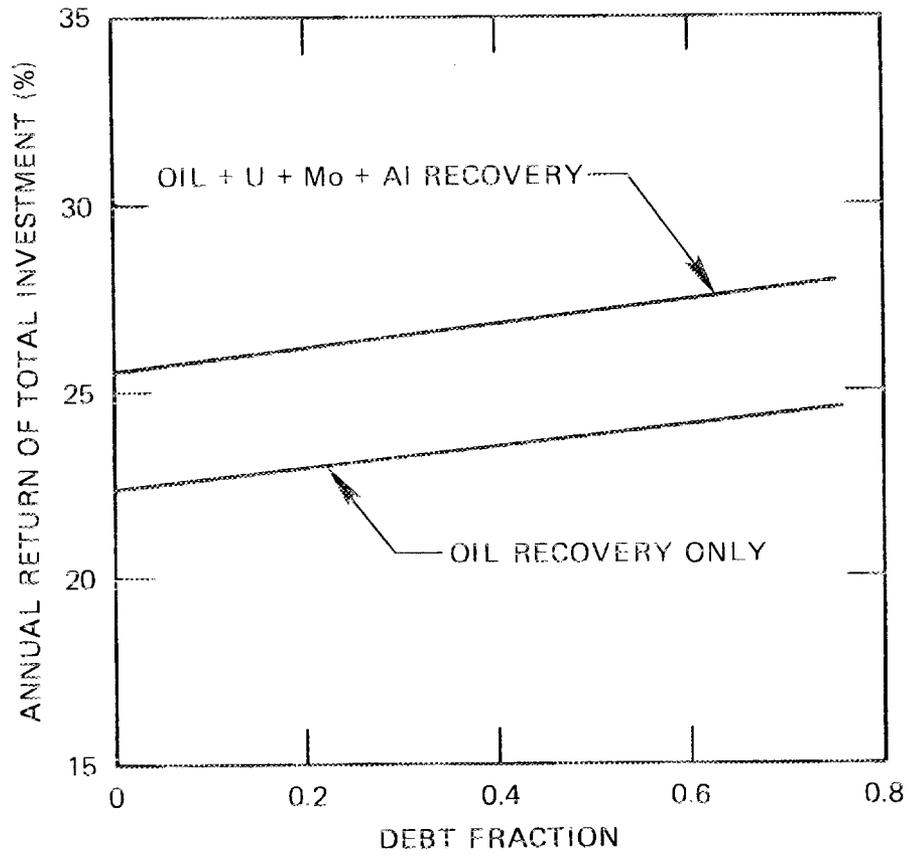


Fig. 6.9. The effect of debt fraction on rate of return on total investment.

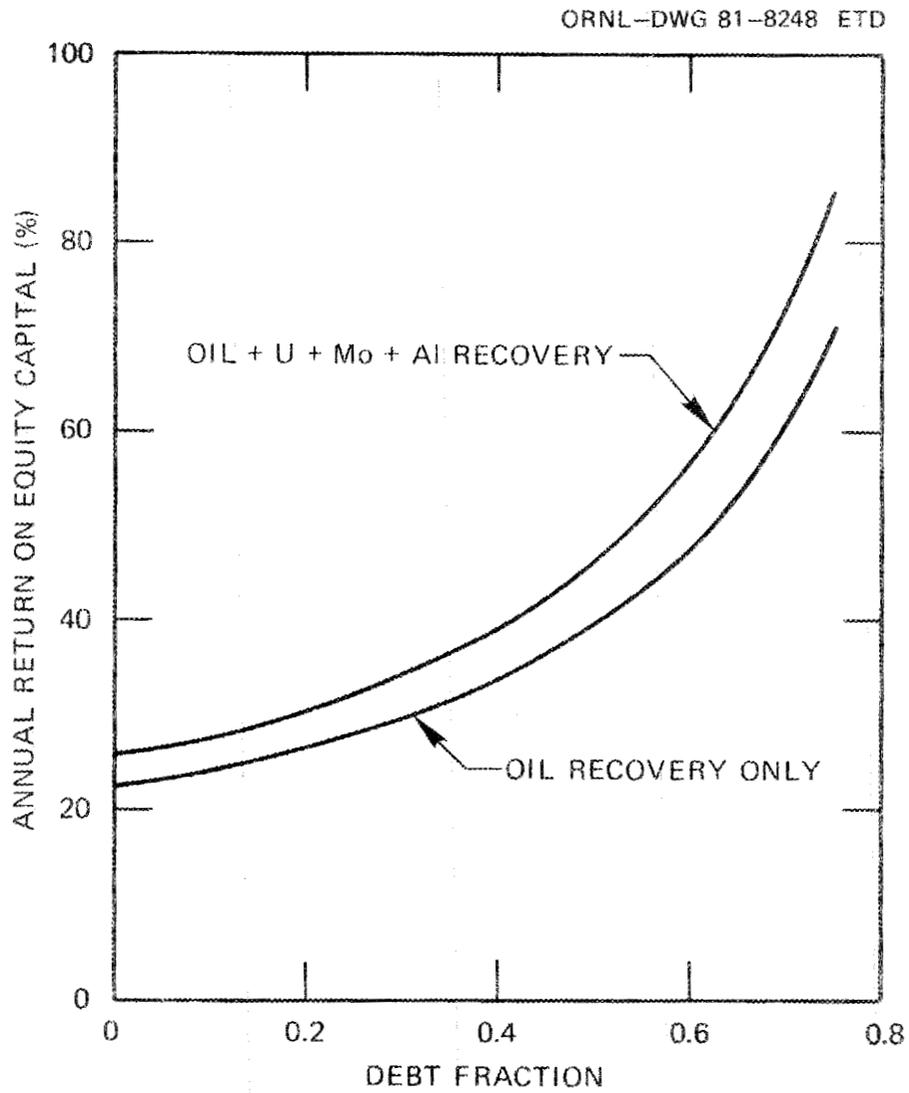


Fig. 6.10. Sensitivity of rate of return on equity capital to project debt fraction.

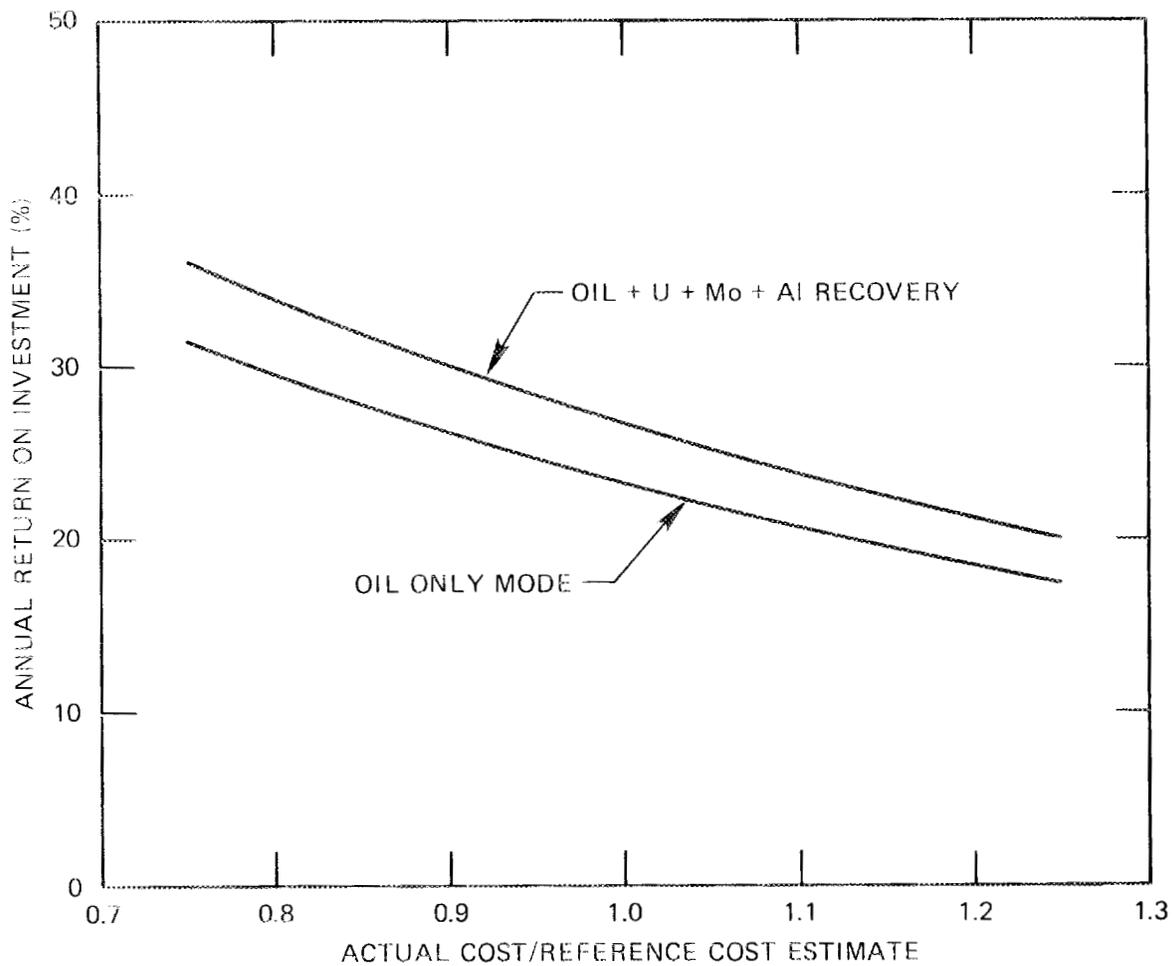


Fig. 6.11. Sensitivity of project return on investment to overall cost uncertainty.

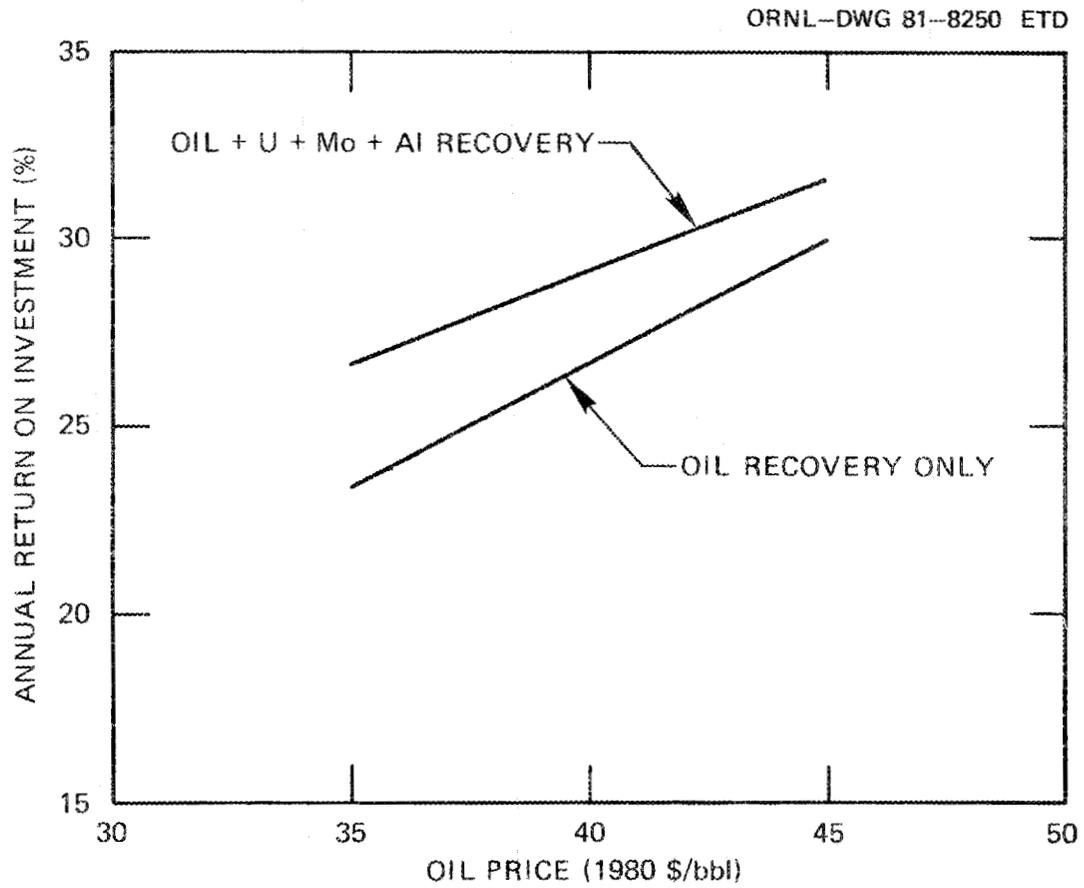


Fig. 6.12. Sensitivity of return on investment to oil price. (Assumes that oil price escalates at a rate of 3% in excess of general inflation.)

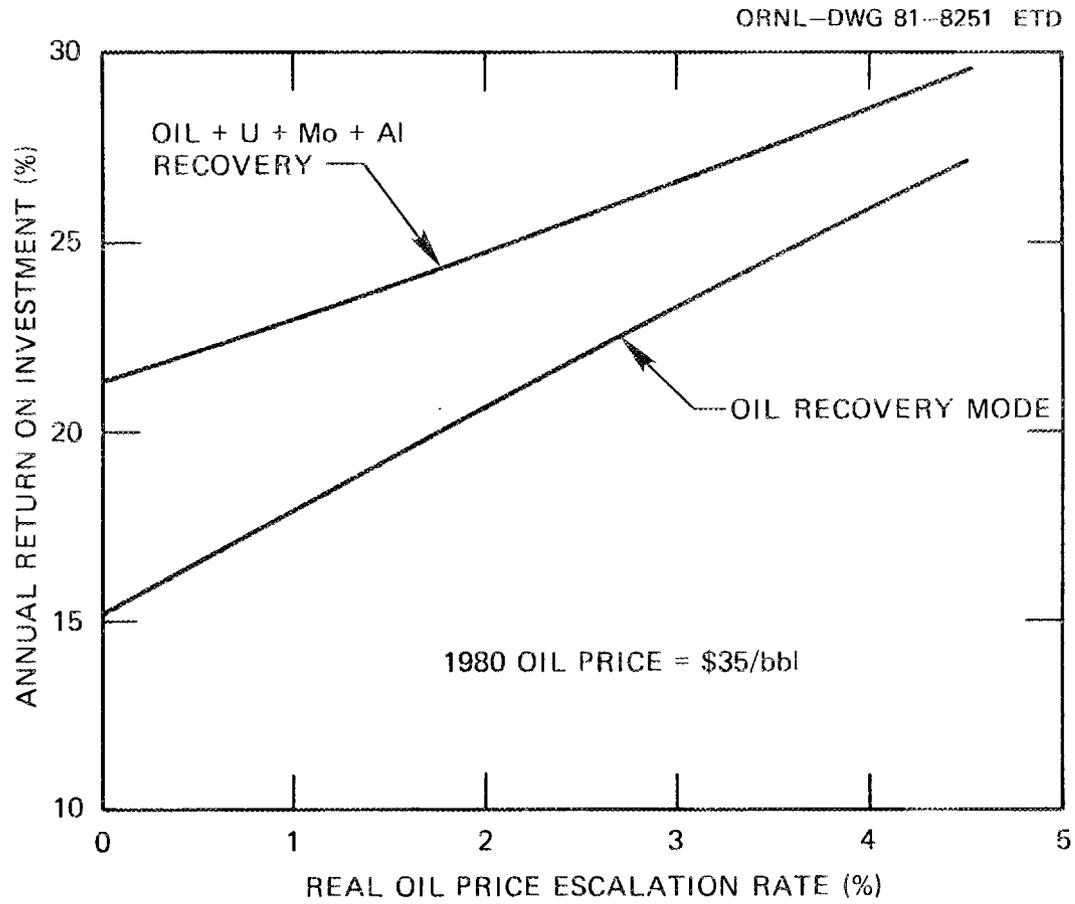


Fig. 6.13. Sensitivity of return on investment to real oil price escalation rate based upon an oil price of \$35/bbl in constant 1980 dollars.

6.5.4 Results with alternate evaluation methods

There are a variety of methods which can be used to compare the economic viability of extracting oil from Chattanooga shale with other technologies. We selected two for this analysis, namely 'constant dollar levelized cost' and 'return on investment.'

Results for the reference case for each operating mode using several alternate evaluation methods are given in Table 6.22. Current dollar levelized costs were explained in Sect. 6.1. Levelized cost without inflation assumes the sudden cessation of inflation; interest on debt and return on equity remain at reference rates. The levelized cost with inflation adjusted returns reduces the interest rates and return on equity by the rate of inflation and removes inflation from all costs. The first year oil cost is based on a revenue requirements calculation as shown in Table 6.23. It is the cost of oil during the first year of operation. The payback period is defined here to be the time required for the cumulative cash flow (excluding return on investment) to equal zero (i.e., the time it takes to recover the original investment through cash flow).

Table 6.22 shows that the constant dollar levelization results are similar to those obtained by the levelization with inflation adjusted returns method. Also the levelization without inflation method produces similar costs to those found with the first year revenue requirements method.

6.6 Conclusions of Economic Assessment

The conclusions are contingent on the validity of the technical and economic assumptions used in the analysis. The processes considered have never been operated in an integrated fashion even on a small scale; their yields and costs must be considered highly uncertain. The costs for waste treatment and disposal and for the final resource recovery step are particularly uncertain inasmuch as the concepts are poorly defined.

Nevertheless, we believe the following conclusions are justified:

- Assuming completion of a technically adequate R and D program, the cost of oil produced from Chattanooga shale should be equal to or below the current market price for oil.

Table 6.22. Oil cost using alternate evaluation methodologies
(\$/bb1)

Evaluation method	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Constant dollar levelizing ^a	35.30	29.60	22.60	26.50
Current dollar levelizing ^b	69.40	58.20	44.50	52.10
Levelization without inflation ^c	46.60	44.40	37.90	45.60
Levelization with inflation ^d adjusted returns	35.30	29.50	22.50	25.20
First year cost (1980 \$) ^e	45.70	44.50	37.90	46.00
Payback period, years ^f	5.5	5.2	4.7	5.5

^aReference costs, equivalent cost in dollars of 1980 purchasing power. The cost in any given year, in that years dollars is related to the 1980 cost through the inflation index. (See Section 6.1).

^bEquivalent cost which remains constant over life of project. Dollar cost does not change although the value of any years dollars changes with inflation.

^cMethod which assumes that the costs and prices remain at 1980 levels and uses reference rates of return.

^dMethod which assumes that costs and prices remain at 1980 levels and the interest rate and rate of return on equity are reduced by the inflation rate.

^eBased on first year operation revenue requirements. (See Table 6.23).

^fTime it takes to pay back original investment through cash flow.

Table 6.23. Oil cost determined from revenue requirements
for first year of operation
(\$/bbl)

Evaluation method	Recovery mode			
	Oil only	Oil + U + Mo	Oil + U + Mo + Al	Full recovery
Operating costs	460.6	623.8	708.0	1,294.3
Book depreciation (20 year)	135.5	169.2	174.0	229.3
Income taxes	13.1	10.6	11.4	18.5
Interest on debt	84.7	106.2	110.0	147.6
Return on equity	338.9	424.9	439.9	590.3
Total cost	1,032.8	1,334.7	1,443.7	2,280.5
Less by-product credit	76.3	403.6	650.0	1,317.5
Net cost (end of 1985 \$)	965.5	931.1	793.7	963.0
Oil cost (end of 1985 \$/bbl)	63.00	61.30	52.30	63.40
Oil cost (mid-1980 \$/bbl)	45.70	44.50	37.90	46.00

- * The return on investment for such a project is in the range of 15 to 35% with typical values ranging from 23 to 27% depending on extraction mode.
- * The venture profitability increases if uranium, molybdenum, and aluminum are recovered along with the oil.
- * The recovery of metals based on complete dissolution of the shale's mineral content does not appear to be economic based on the present concept.

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7. ASSESSMENT OF ENVIRONMENTAL IMPACTS

The environmental impacts of producing oil and minerals from the Chattanooga shale formation by means of underground mining and surface retorting have been assessed and are summarized in Table 7.1. The design information on which this assessment is based is sketchy and the assessment therefore is only tentative. Other issues would be identified during development, detailed design, and site selection.

No inherently beneficial environmental impacts have been identified. Negative impacts are rated as high, medium or low, where high indicates a constraint to development, medium indicates need for mitigation at increased cost to the operation, and low indicates mitigation costs that would fall within the usual cost of business of a minerals industry. The basis for impact assessment and the assessments are summarized below.

7.1 Geologic Impacts

Potential geologic impacts include conflicts with the development of other mines and resources and land disturbance due to mine-related subsidence. Other mineral resources of the region in which shale development is most probable might include oil and gas in formations beneath the Chattanooga shale and methane within the shale. Methane within the shale is considered an 'unconventional' source and is not presently economically recoverable. It may be possible to recover this type of gas concurrently with shale mining following additional R and D on unconventional gas recovery. Mining of the shale would increase development costs of potential underlying oil and gas reserves, however such development would not be precluded by mining of the Chattanooga shale.

The environmental impact from subsidence is difficult to predict in a generic assessment. It has been rated medium because of its potential to occur near to the outcrop and the necessity to design mines to avoid undermining towns, highways, reservoirs, and other sensitive areas. For the most part, however, the Fort Payne formation is expected to provide a competent roof and provide little subsidence potential.

Table 7.1. Summary of environmental impacts from an 8,000 m²/d (50,000 barrel/day) shale oil industry in the Chattanooga shale outcrop

Nature of impact	Level of impact ^a
Geology	
Resource recovery	Low
Subsidence	Medium
Water	
Groundwater	High-to-medium
Surface water	Medium
Water use	Low
Wild and scenic rivers	Low
Land	
Land use	High
Soils	Medium
Natural and scenic areas	Low
Atmosphere	
Air quality	Medium
Noise	Low
Biology	
Direct terrestrial	Medium-to-low
Secondary terrestrial	Low
Revegetation	High-to-medium
Direct aquatic	Medium
Secondary aquatic	Low
Recovery	High-to-medium
Endangered species	Medium
Socioeconomics	
Demography	Low
Labor/economics	Low
Housing	Low
Quality of life	Low
Transportation	Low
Historical/archaeological	Low

^aHigh - a potential constraint to development.

Medium - require extra-cost mitigation.

Low - mitigation costs, if required, fall within normal costs of business.

7.2 Impacts on Water

Impacts to groundwater will be highly site specific. Medium impacts are predicted regionally, primarily due to leaching of toxic metals from raw and retorted shales (see Table 7.2). Extra costs will be incurred where shale is mined, stored, and processed and where the spent shale is returned. Potentially high impacts exist locally where the Chattanooga formation underlies important aquifers, and mining could drain the aquifers.

Impacts to surface water also will be site specific, but no constraints are seen. While there exists a potential for severe impacts, those impacts should be mitigable with environmental control technology. Since primarily underground mining is expected, impacts to surface hydrology would occur primarily as a consequence of changes in groundwater hydrology and secondarily as a consequence of surface waste disposal. Leaching of metals and acid drainage can be mitigated through operations design and water treatment prior to off-site release.

Water availability is expected to be a major consideration in siting a shale processing facility. Otherwise, water use impacts are expected to be low because of excess flows projected far beyond the year 2000.

Low impacts to wild and scenic rivers are predicted. No federally designated streams lie within the prime resource area although some state-protected streams do.

7.3 Impacts on Land

Land use impacts will be high, primarily due to the large areas which may be needed for surface waste disposal. The fact that land is held in smaller parcels in the region and the industry will lack condemnation authority could prove to be a significant constraint to development.

Table 7.2. Leaching characteristics of
1- to 2-mm diam Chattanooga shale
(ppm, except pH)

	Raw shale ^a	Hydroretorted shale ^a
pH	2.5-3.0	4.3-7.0
SO ₄	7600-560	250
Fe	2200-148	0.5-0.05
Al	221-20	0.38-0.1
Ca	112-25	3.4-0.2
Co	11-0.8	0.1-0.1
Cu	13-0.7	0.1
Mn	8.9-0.7	0.1
Mo	2.5-0.1	2.2-0.5
Ni	28-22	0.1
Zn	56-4.4	0.1

^aRange, 20 Aliquots. Shale is subjected to a continuous leach with 20 volumes of water. The initial and final concentration of material in the water is reported.

Impacts to soil are judged to be medium and derive primarily from waste disposal. It is assumed that valleys chosen for waste disposal do not represent better agricultural areas but that large volumes of topsoils will be required for application to the surface of disposal shale.

Natural and scenic areas are generally lacking in the prime resource area, and impacts will consequently be low.

7.4 Impacts on Atmosphere

A shale processing plant can generate up to about 2250 Mg/d (2500 t/d) of H₂S. However, environmental control technology capable of ≥99% recovery exists, and impact is rated at medium. Production of sulfuric acid for metals recovery would further reduce the atmospheric pollution potential. Other air pollutants are highly process dependent and are not assessed. Noise impacts are rated low, primarily because of being in a rural environment.

7.5 Biologic Impacts

Direct impacts to terrestrial ecosystems should be medium-to-low. Although the area potentially disrupted is large, it remains less than 10% of the region and lacks unique qualities. Habitat restoration, by means of spent shale stabilization and revegetation, will be an extra-cost mitigation. Secondary impacts, such as vegetational degradation from increased air pollution, will be minimal. Revegetation of waste disposal sites will be a major cost to the industry. To date, no direct research has been done in this area but preliminary indications are that it will prove to be considerably more expensive than revegetating surface coal mine spoils and may be similar, but much more extensive, than revegetating wastes from underground coal mines. Impacts will require extra-cost mitigation (medium impacts) and may prove to be a financial constraint (high impacts).

Direct impacts to aquatic ecosystems occur during mining and are in the form of direct disruption and receipt of materials in suspension or solution from the mined site. Impacts are medium since control requires extra-cost mitigation in the form of engineered structures and treated water releases. Secondary impacts are rated low.

Recovery of damaged aquatic systems is dependent on the control of effluents from the surrounding uplands areas. In general, successful stabilization and revegetation of mined and disposal sites will lead to recovery of receiving waters.

Impacts to endangered and otherwise sensitive species should be medium. While relatively few such species occur within the prime resource region, and obviously few individuals occur, the presence of a protected species could lead to extra-cost mitigation measures, such as avoiding the area or providing for the maintenance of the affected population.

7.6 Socioeconomic Impact

The development of a shale industry in the prime resource area would have locally significant 'boom-town' effects, but impacts are rated low since the major costs will be externalized by the industry. There will be population growth impacts and transportation impacts which will be borne by local residents, for the most part willingly, in return for the benefits of an expanded local economy and the opportunities for growth in the service sector. There will be short-term trade-offs in the quality of life but in the longer term the quality of life should remain high. Housing will be heavily impacted in the short term but should improve both in quality and quantity with time. Impacts to historical and archaeological resources will be minimal due to the low frequency of occurrence in the area.

8. RESEARCH AND DEVELOPMENT NEEDS

Chattanooga shale, a large and mineral-rich member of the Devonian oil shales of the eastern United States, appears to offer significant potential for the commercial recovery of valuable hydrocarbons and scarce minerals through reasonably foreseeable extensions of current technology. A starting point for the development of technology from Chattanooga shale and other eastern Devonian shales is provided by the development through near commercial scale of processes for recovery of oil from shales in the Green River formation of Colorado, Utah, and Wyoming. Specific research and development is required for recovery of values from Chattanooga shale, however, because this material differs in several important aspects from western shale and in some aspects from other Devonian shales. As compared with western shales, in which carbon and hydrogen are associated with the largely aliphatic structure of kerogen and may be liberated rather easily by heating, Chattanooga shale has approximately the same content of organic carbon (12 to 15% by weight), lower hydrogen content, and hydrocarbons that are less subject to recovery by thermal decomposition because a significant fraction are polycyclic aromatics in macerals that are similar to those found in coal. Chattanooga shale is also more highly laminated than western shale and forms platelets, rather than granules, upon crushing. Chattanooga shale differs from most other Devonian shales in that it has significantly higher concentrations of some important minerals such as those of uranium. These aspects of Chattanooga shale dictate that steam-oxygen gasification, hydrogasification, and/or spent shale combustion be considered -- as an adjunct to simple retorting -- as part of the hydrocarbon recovery process and that this process should leave the remaining silicate structure in a form that is readily leached for minerals recovery.

The purpose of this chapter is to identify needs for research and development that are required to establish the scientific and technical feasibility and the commercial viability of the recovery of hydrocarbons and minerals from Chattanooga shale. The perceived needs include those for (1) resource assessment, (2) mining, (3) process development, and general supporting research and development, for (4) upgrading and refining of shale oil, (5) basic chemical and physical research, (6) materials, (7)

instruments and controls, (8) design and planning studies, (9) environmental control technology, and (10) health and environmental effects.

The envisioned program for exploitation of Chattanooga shales is expected to progress along basically two avenues: (1) work that could proceed rather quickly to pilot plant scale for oil recovery from related Devonian shales through attempts to adapt the technology for recovery of oil from western shales and (2) work at a more deliberate pace that would seek to develop processes tailored to the unique aspects of Chattanooga shale. Work of the first type can begin with retorting of Devonian shales in experimental units that are available for retorting of western shale. If there is initial success in such tests, test mines and pilot plants could be operated in regions where the shale is located, and substantial early work would be appropriate for the supporting areas including environmental control technology and health and environmental effects. Work to exploit specific aspects of the Chattanooga shale would begin with laboratory and bench-scale experiments to fully characterize the shale; evaluate mechanisms, enthalpies, and kinetics associated with pyrolysis, gasification, hydrogasification, and combustion of the shale; and investigate alternative methods for the recovery and separation of metals.

The compilation of research and development needs that will be presented has made extensive use of studies that were made recently by W. R. Grimes and other members of the staff of the Oak Ridge National Laboratory (Grimes 1979 and Grimes 1980). Many useful references to the recovery of synthetic fuels from oil shale have been published as papers from a recent symposium (IGT Symposium Papers 1980).

The most pressing need for research and development associated with the recovery of energy and strategic materials from Chattanooga shale is for laboratory and bench-scale work that may be used to make preliminary evaluations of the feasibility of alternative processes. There is also a serious lack of information on health and environmental effects that could guide the choice of methods of mining, processing, and waste disposal.

8.1 Resource Assessment Research

Most of the existing information on the Chattanooga shale comes from work that was performed in the 1950s. The major objective of much of the early work was to evaluate the Chattanooga shale as a source of uranium. Hydrocarbon yields were determined on scattered samples resulting in a sparse data base for the hydrocarbon potential of the shale. More recently, additional work has been undertaken to assess the metals content of the shale (Mutschler 1976 and Leventhal 1979). Much of the early work indicated that shale outcrops in DeKalb County, Tennessee, would provide the most favorable reserves for initial development of the Chattanooga shale. For this reason more data have been obtained in DeKalb County than in other adjacent areas along the basic geologic feature that is termed the Eastern Highland Rim. Other work that is needed to select most promising areas and sites for initial commercial development of the shale includes the following.

8.1.1 Geology and geohydrology

Perform additional core drilling and well testing -- especially in the Tennessee counties of DeKalb, Putnam, and Coffee along the Eastern Highland Rim -- to provide data for more accurate estimates of (1) the reserves of hydrocarbons and minerals associated with the shales, (2) the properties of outcrops, seams, overburdens, and aquifers needed for studies of surface mining, (3) mechanical, thermal, and hydrological properties of the shale and contiguous formations needed for studies of underground mining, and (4) the extent of other resources of potential interest within the geological column.

8.1.2 Geochemistry

Make more complete investigations of the organic and inorganic constituents of the shales -- the kerogen and macerals associated with the organic constituents, the specific mineral species, the trace elements, and correlations of these with the geologic history of the formations.

8.1.3 Geography and demography

Perform studies to more accurately determine topography, present uses and ownership of land, uses of water, and the distribution of population, plant, and animal life. This will overlap with later and more site specific studies of ecology and water and air quality to provide background data for studies of environmental impacts.

8.1.4 Socioeconomic and institutional research

Investigate the types of communities, levels of private and public services, and legal and organizational frameworks that will most likely be affected by shale processing and attendant secondary industries so that an accurate assessment of the impacts on society can be made.

8.2 Mining Research and Development

Technology base needs for underground shale mining include the following:

a. A well-planned and optimally designed mine will maximize shale production and mine safety and will minimize the impact upon the local environment. Mine planning and design requires data about, and understanding of, the mine site and environs; mine stability and water intrusion are expected to be important considerations in the selection and development of mining methods for Chattanooga shale.

- Improved diagnostic tools for down-hole logging, and particularly for obtaining information about strata at appreciable distances from the hole are needed.

- Useful information could be obtained by improved geophysical techniques for remote sensing and for mapping of detailed geologic, stratigraphic, and hydrographic features of the site.

- Improved methods are needed for predicting flow patterns, as well as quantities and concentrations of (methane-bearing and radioactive) gases and water in the mined areas and adjacent strata as functions of mining operations.

- All of the available data needs to be included in mine simulation models that can allow predictions of behavior under different mine sequencing operations.

- Combination of the mine simulation model with an economic model would permit optimization of operations and costs.

b. Mine development includes providing access shafts to the shale seam and use of cutting and roof-bolting machinery to cut roadways into the seam to provide production centers.

- Mine development (as well as mine planning) needs an improved understanding of rock mechanics and the fundamentals of how rocks and shales respond to stress.

- Improved methods and devices are needed to determine in situ stresses within the seam and, especially, adjacent formations prior to and during mining operations.

- Improved quick and accurate procedures are needed for determination of physical and mechanical properties of shales and adjacent rocks and for correlation of these with ease of drilling and cutting.

- Alternatives to conventional roof-bolting, which have been accepted in other countries, need to be examined for cost effectiveness and safety under U.S. conditions.

- Both experimental data on pertinent properties and stress levels and theoretical studies are needed to assess roof-fall probabilities and associated safety hazards.

c. Mine subsidence can be a problem.

- Improved understanding of rock mechanics and of the ways in which roof strata and overlying layers respond to stress in the long term is needed.

- More detailed information about rock properties and stress levels is needed in specific areas where mine subsidence might be expected.

- Comprehensive theories that relate the properties of the overlying strata, the mining method, and the nature of the residual pillar structure to the occurrence of surface subsidence and damage to aquifers and to surface structures are needed.

d. An experimental mine should be operated to evaluate mining methods and equipment and to provide data for mine design and cost estimation.

8.3 Process Research and Development

8.3.1 Directions for hydrocarbon recovery process development

As indicated in the discussion of oil recovery process in Chapter 5, processes which have been developed for western shale do not appear attractive for eastern shale without major modifications to improve carbon recovery. IGT's Hytort process, devised specifically for eastern shales, does have improved carbon recovery but at the expense of reduced gas yields and general process complexity.

Since much of the organic portion of eastern shale resembles the organic material in coal, the process information and R and D tools which have been applied to coal liquefaction and gasification may be applicable also to eastern shale processing. Alternatives to existing shale-oil recovery processes could involve combinations of the following elements:

- a. Preheating of the shale to about 300°C (572°F) using regenerated heat. Oil is not produced below this temperature.
- b. Retorting in an inert or hydrogen atmosphere at up to about 538°C (1000°F). The bulk of the kerogen decomposition occurs below this temperature.
- c. Gasification of the char by partial oxidation (steam + oxygen) at above 538°C (1000°F). It is necessary to avoid overheating if resource recovery is desired as in the case of Chattanooga shale.
- d. Heat recovery from the spent shale via heating water, gas, or direct-contact with incoming shale.
- e. Rapid heating of incoming shale. Yields of liquids from coal have been enhanced by rapid heating; it is unknown whether shale would have similar properties.
- f. Combustion or gasification of fines to recover energy and to reduce the environmental impacts of fines disposal.

One plausible combination of these elements could include use of a conventional Lurgi dry ash gasifier, as illustrated in Fig. 8.1. The downward moving bed of shale would, in turn, be heated, retorted, gasified, combusted, and cooled within the 500 psi gasifier. A substantial hydrogen partial pressure should enhance oil production as in the Hytort process. The products of this process are expected to be a hydrotreated high-quality light crude (as in Hytort) and SNG. Unfortunately, it may be necessary to burn part of the hydrogen produced in the gasifier to heat shale in the retort zone. In the R and D program, it would be desirable to find some regenerative sources of heat that would reduce or eliminate this inefficiency.

Another plausible combination of these elements is shown in Fig. 8.2. Crushed shale is fed into a fluidized retort heated by solids recycled from the gasifier (similar to the Lurgi-Rhurgas technology). The steam synthesis gas atmosphere of the retort combined with rapid heating should somewhat enhance oil production above the Fischer assay. The products of this process are expected to be hydrotreated high-quality, light crude, SNG and synthesis gas ($\text{CO} + \text{H}_2$). The synthesis gas could be shifted for methanol or SNG production.

It will be necessary to integrate process development with health, safety and environmental considerations. If minerals are to be recovered from the spent shale, additional constraints may be introduced into the retorting operations. The following are some of the more obvious considerations:

- a. It may be necessary to produce solid wastes low in sulfur to avoid environmental leaching of sulfates.
- b. It may be necessary to process or roast fines to avoid leaching of undesirable materials.
- c. It may be necessary to avoid overheating of the shale prior to leaching for minerals recovery.

8.3.2 Directions for minerals recovery process development

The work on minerals recovery from Chattanooga shale has been limited to laboratory and bench-scale studies (Brown 1950, Columbia 1955, Gilliam

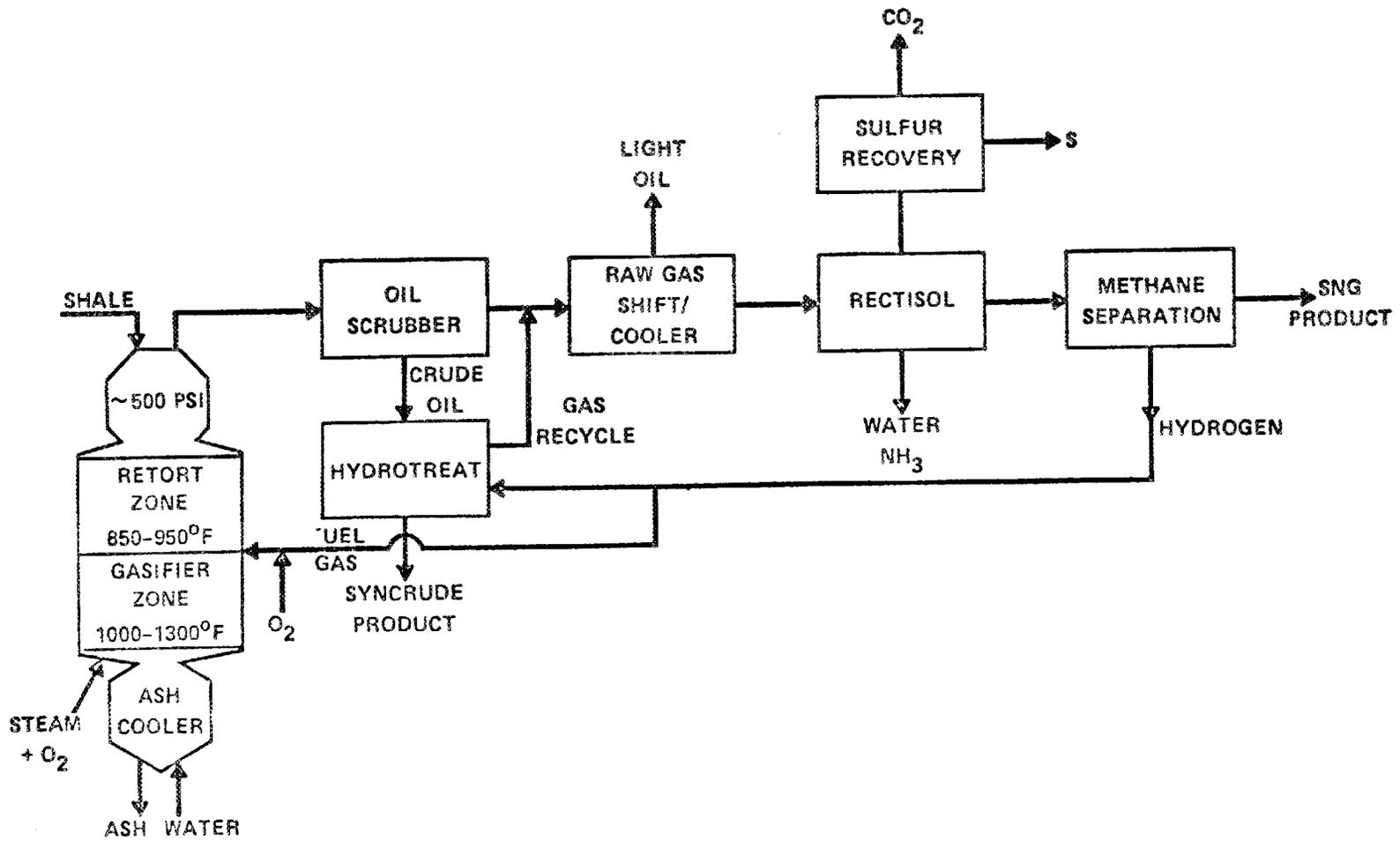


Fig. 8.1. High-pressure partial oxidation shale retort.

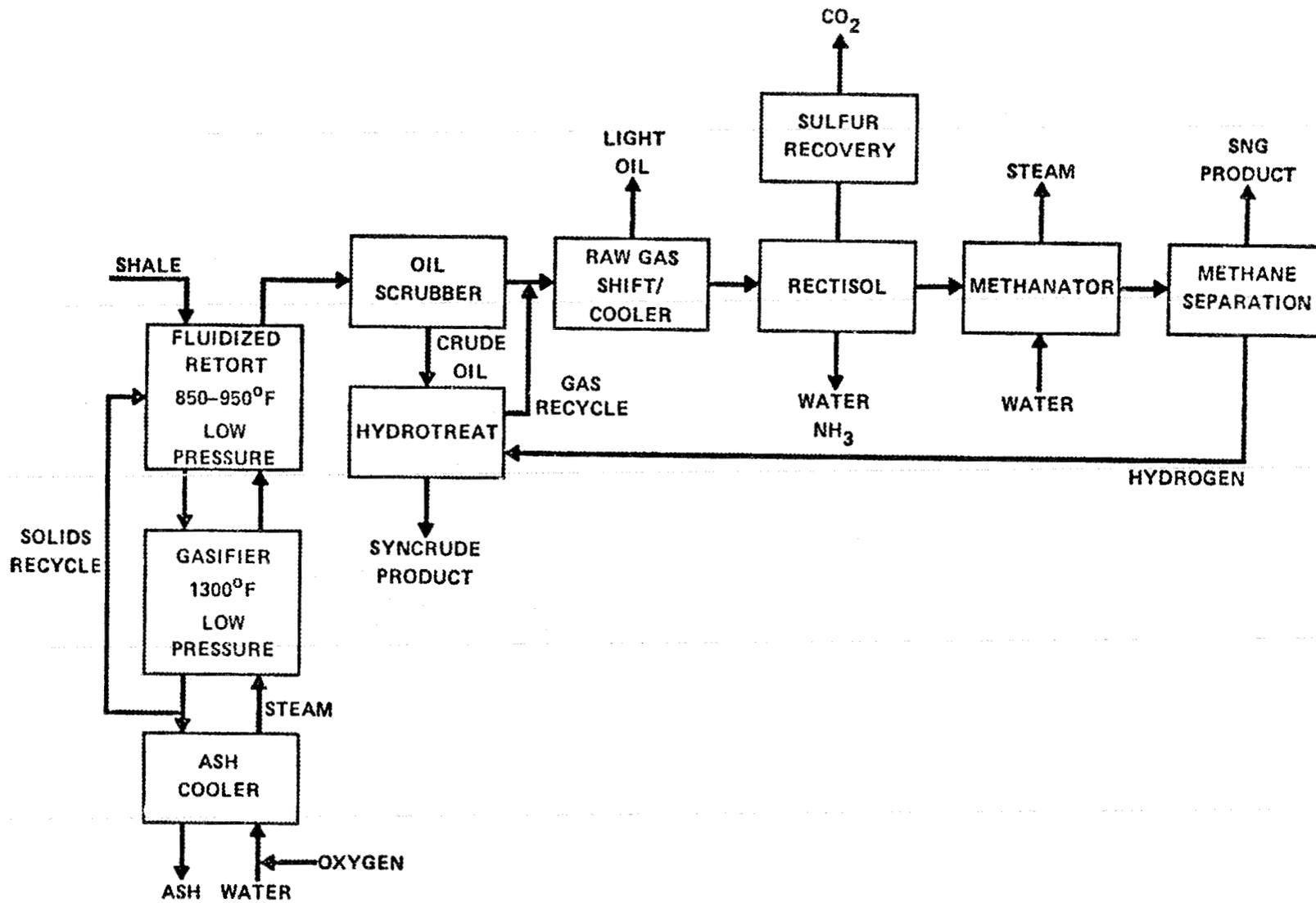


Fig. 8.2. Shale gasifier/retort.

1981, and Silverman and Spiewak, 1981). These have included studies of leaching of roasted or hydroretorted shales with acids and separations and recovery techniques including solvent extraction and selective precipitation. In addition, there has been extensive development in Sweden of processes for recovering uranium and other minerals from the Ranstad shales (Andersson, 1978). Techniques being developed currently at ORNL for the recovery of minerals from fly-ash could also be applicable to shales.

R and D should be done in an orderly manner to provide the bases needed for economical metal extraction and recovery processes, including waste treatment. Different process concepts are likely to be preferred depending upon the metals to be recovered. Currently, the most promising targets for mineral recovery are alumina, cobalt, uranium and molybdenum. Future circumstances may influence these priorities. For example, depletion of present sources of uranium and molybdenum could substantially increase their value whereas cobalt may become much more available if the deep-sea nodules are mined. The economic analysis which was performed suggested that partial dissolution of the preferred minerals is likely to be more attractive than full minerals recovery, and research should proceed in that direction.

One plausible, but unproven, combination of process elements is shown in Fig. 8.3. Solids removal from a retort/gasifier are crushed and separated magnetically. The magnetic fraction, which would contain most of the iron, nickel, cobalt, uranium, molybdenum, and other trace metals, would be subjected to an alkaline (ammoniacal) leach to recover the more valuable constituents from the iron-alumina-silica matrix. The nonmagnetic fraction, depleted in iron, could be leached with acid to recover alumina and residual uranium and molybdenum.

Many other process permutations are possible and should be considered during the initial exploratory studies. The metals recovery processes must be compatible with the retorting process selected which will influence the chemical nature of the metallic constituents and the sulfur recovery (for acid production). Flowsheet data are needed for both HCl and H₂SO₄ to permit consideration of different recovery processes for different metals.

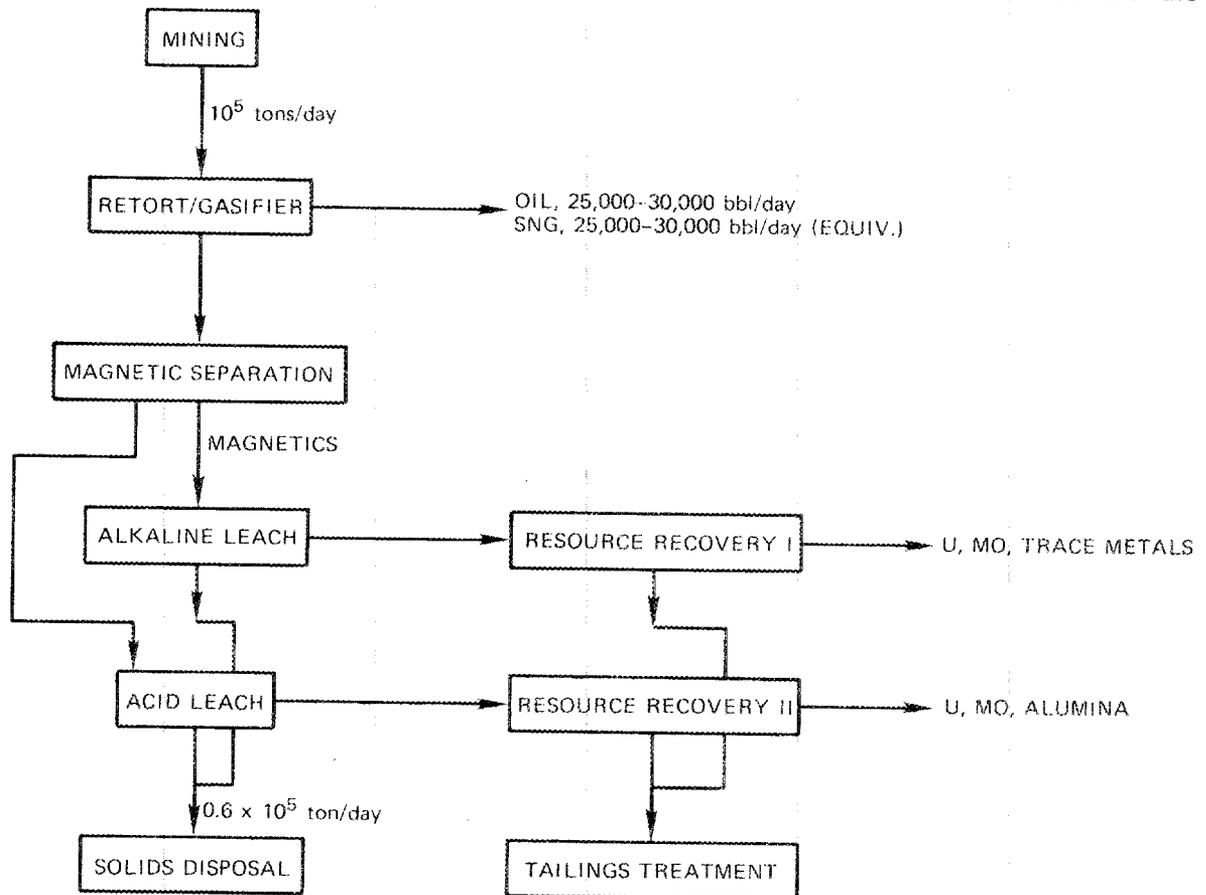


Fig. 8.3. Chattanooga shale process diagram alternative improved process.

Disposition of the fines produced during crushing of the shale represents a significant R and D problem since most retorts will not accept them. A 100,000 ton/day mining operation is likely to produce on the order of 10,000 ton/day of fines. The fines should preferably be roasted or gasified to recover energy and then processed for metals recovery with the bulk of the spent shale.

8.3.3 Laboratory and bench-scale studies

Laboratory and bench-scale studies are needed to permit evaluation of the scientific and technical feasibility of alternative unit operations for the recovery of hydrocarbons and minerals from Chattanooga shales.

A key step in the processing of Chattanooga shale may be the steam-oxygen gasification of char produced in the retorting zone. It has been reported that Israeli shale-char is very reactive with steam (Schachter 1979). Experiments should be run with Chattanooga shale-char to determine the rate of reaction with steam as a function of temperature in the range of $>600^{\circ}\text{C}$. Other experiments should determine the gas composition generated in steam-oxygen gasifiers as function of temperature $>600^{\circ}\text{C}$.

Another important process unknown is the yield from retorting eastern shale in steam-syngas atmospheres. The hydrogen partial pressure should enhance hydrocarbon production based on IGT data (Feldkirchner 1980). Steam has been observed to enhance oil production from western shale (Allred 1980); its effect on eastern shale is unknown and should be measured. These properties should be measured at pressures from atmospheric to about 500 psi. Retorting temperatures are expected to be in the vicinity of 500°C (932°F).

Other property measurements that are needed include heat capacities of the solids and liquids; heats of transition; heats of reaction and free energy as a function of temperature; and the viscosity, composition, and vapor pressure of the derived oils as a function of temperature.

Laboratory and bench-scale work on minerals separations technology should include studies of leaching reagents, ion exchange, solvent extraction, precipitation, magnetic separations and electrochemical methods.

Use of bioagents such as ferrobacillus should be scouted. These exploratory studies, combined with design-economics studies, should culminate in the selection of preferred flowsheets for resource recovery.

When concepts for metals recovery are developed, the processes should be demonstrated on a bench scale to obtain products for purity analysis and to measure reagent consumption for cost estimates. The waste streams should be analyzed and characterized. Eventually source terms of potentially hazardous elements need to be described and waste treatment methods developed.

8.3.4 Process equipment development

Following the selection of the most promising processing steps, larger-scale work in process development units and pilot plants will be required to develop an overall, energy efficient, integrated process. The cost of the program will increase as the scale of the facilities increases, as shown in Tables 8.1 and 8.2.

8.4 Supporting Research and Development

8.4.1 Basic chemical and physical research

Chattanooga shale is significantly different in chemical and physical properties from western oil shales and, in some respects, from other eastern Devonian shales. While the total contents of organic carbon are approximately the same, the hydrogen content of Chattanooga shale is lower and a significantly higher fraction of the carbon is in the form of multi-ring aromatic structures rather than the aliphatic structures that are predominant in western shales (Minkis 1980). Only a portion of the organic carbon in Chattanooga and other Devonian shales is in the form of kerogen that can be decomposed thermally to liberate oil. Half or more of the organic carbon appears to be in the form of macerals (fusinite, exinite, and vitrinite) that are typical of those found in coal. Physically, Chattanooga shale, like other Devonian shales, is highly laminated and, upon crushing, tends to form slivers and platelets as opposed to the

Table 8.1. Estimated parameters of commercial and experimental units for the recovery of hydrocarbons and minerals from Chattanooga shale

	Shale feed rate		Equivalent oil product (bbl/d)	Retort diameter (ft)	Capital cost ^a (\$10 ⁶)	Annual operating cost (\$10 ⁶) ^a
	Tons per day	Pounds per hour				
Commercial plant	100,000		60,000	23	2500 ^b	500 ^b
Pioneer plant	30,000		18,000	23	1100	180
Pioneer plant module	5,000		3,000	23		
Pilot plant	500		300	7.3	60	8
Process development unit	25	2,000	15	1.6	8	2.0
Bench scale unit	1	80	0.6	0.33	1.5	1.0

^aAll costs in 1980 dollars.

^bBased on estimates by J. G. Delene of ORNL of commercial plant for recovery of oil, gas, uranium, molybdenum, and aluminum.

Table 8.2 Estimated properties of commercial and test mine for Chattanooga shale

	Commercial mine	Test mine
Capacity, tons/d	30,000	500
Operating staff	400	20
Capital cost, \$10 ⁶	90	4.0
Annual operating cost, \$10 ⁶	30	1.6
Unit shale cost, \$/ton	6	25

lumps that are formed by crushing of western oil shales. The Chattanooga shale differs from most other Devonian shale in that it has significantly higher concentrations of several important minerals. All of these properties of Chattanooga shale should be investigated to form the basis of improved processes for the recovery of hydrocarbons and minerals. Because of the similarities between some of the organics in eastern shale and those in coal, the shale research might benefit from some of the facilities and technology which have been developed for coal.

The following is a list of technology needs:

a. A better understanding is needed of the composition and structure of the shale and of hydrocarbons derived from them. Particular needs are:

- Improved methods to establish the concentration of heteroatoms (particularly N) and the identity and quantity of the functional groups in which they occur.
- Improved understanding of the structure of the carbon skeleton and of the extent and nature of cross-linkages.
- Recognition of the scissile bonds and reactive configuration with the kerogens, macerals, and oils.
- Determination of concentration and nature of bonding of metals and trace elements (including As) in hydrocarbons and oils.
- Improved understanding of variations in structure and geochemistry as functions of geologic province, formation age, formation leaching, etc.
- More complete definition of the inorganic components, including trace elements, the specific mineral species, and correlations of these with geologic history of the materials.
- A rapid, inexpensive method for assay of specific minerals in the shale.
- Fundamental relationships among characteristics of minerals, physical properties of the shale, and optimal grinding regimes are needed to assist in optimization of physical, gravity, magnetic, and surfactant separations of minerals.

b. Pyrolytic and gasification reactions, conducted under a variety of conditions and atmospheres and generally including oxidation of char

and some of the other products, seem certain to be used for near-term recovery of values from shales. An improved understanding of the chemical and physical processes is needed. Special needs are:

- The paths, mechanisms, energetics and rates of dominant reactions that produce volatile products and chars during pyrolysis, gasification, and oxidation of hydrocarbons and high molecular weight products need study under moderately inert atmospheres (as in some indirect heating modes) and under atmospheres produced by gasification and combustion of spent shale.
 - Determinations of the extent to which free radicals are formed and can be stabilized, thereby leading to more volatile products.
 - The effect of hydrogen atmospheres upon the pyrolysis reactions and products needs to be established.
 - Mechanisms, including those of mineral catalysis and rates of gasification of char by CO_2 and by steam, need to be established.
 - Markedly improved understanding of reactions of the shale minerals during the hydrocarbon recovery sequence is needed.
 - Porosity, permeability, and pore structure of the matrix materials need to be determined along with changes in these during hydrocarbon recovery.
 - Changes in heat transfer and mechanical properties of the matrix during pyrolysis need to be established.
 - The extent of catalysis of pyrolysis, gasification, and combustion of the organic materials by mineral matter needs to be examined and means for enhancement of catalytic effects need to be explored.
- c. Certain aspects of product behavior during retorting and temporary storage need additional study.
- Nucleation, condensation, and settling behavior of oil mists in the product gas need to be established to permit effective recovery of oil product.
 - Rheology and density of intermediate and product oils and means for breaking of emulsions and separation of solid particulates need to be understood.
 - Mechanisms by which product oils deteriorate in temporary (pre-upgrading) storage need to be defined.

- d. Spent shales will be returned to the mines or disposal sites.
- * Alternative methods of spent shale transport and compaction need investigation.
 - * Flow properties and de-watering properties of spent shale slurries need to be determined along with means for purification of the water used in their transport.
 - * Mechanisms and rates of compaction, resolidification, and cementation of spent shales need investigation.
- e. The possibility of useful recovery of shale oils and minerals by novel methods should be explored in small-scale experiments to establish feasibility. Such concepts include:
- * Steam retorting of shales.
 - * Increased product yield by free radical stabilization via hydrogen donors.
 - * Novel and high-risk possibilities such as microwave, radio-frequency, or solar heating for retorting.
 - * Conversion of hydrocarbons to valuable products by use of microorganisms.
 - * Combinations of pyrolysis with solvent action have apparently received much less attention for oil shales than for coals. Recovery of liquid solvents from the large inorganic mass is likely to be difficult. A basic study of solvent and supercritical fluids as solvents might lead to valuable insights as well as possible processing methods: supercritical fluids that have good hydrogen donor capabilities would be an interesting possibility.

8.4.2 Oil upgrading and refining

Upgrading and refining of heavy oils produced from petroleum is a highly developed commercial practice using techniques such as hydro-treating, hydrocracking, and catalytic cracking. Such techniques have been adapted with generally good success by companies including Chevron, Ashland Oil, Sun Oil, and United Oil Products to the upgrading and refining of batches of oil derived from western oil shale in experimental retorts (Sullivan 1980 and Coppola 1980). These techniques, catalysts

such as the widely used cobalt molybdate hydrodesulfurization catalyst, and equipment using fixed and ebullated catalyst beds will provide a point of departure for the commercial upgrading and refining of shale oils. The following, however, will point out some of the specific problems that are associated with shale oil and types of research that could lead to improved processes.

a. The high nitrogen content, the instability of the oil and of its distillates, and the presence of trace elements all pose problems that require further study.

- The functional groups in which nitrogen appears in the oil and distillate fractions need to be identified to guide development of improved methods for denitrification.
- The nature and concentration of reactive groups and the chemical reactions responsible for oil and distillate instability need to be understood to suggest improved stabilization methods.
- A better understanding of the trace element concentration and behavior is needed to assess the extent of special problem areas.

b. Hydrotreating will be used as a key step in direct refining of shale oil or as a step in preparation of shale oil for transport and blending with petroleum for combined refining.

- The extent of hydrotreating (extent of removal of nitrogen and reactive groups) required for direct refining and for blending with petroleum needs to be established to permit choice of proper strategy.
- The effect of trace metals upon hydrotreating and hydrocracking catalysts needs to be determined, and means for mitigation of detrimental effects, if any, need to be established.
- Improved catalysts are needed for more selective denitrification and hydrocracking at lower temperatures and pressures with smaller consumptions of hydrogen.

c. Alternative methods, including biochemical methods, for upgrading shale oil for direct refining or for blending with petroleum should be studied.

- Processes that involve minimal hydrotreating followed by nondistillative separation schemes should be investigated.

- Methods that affect sufficient purification and stabilization for refining without use of hydrotreating should be sought.

d. Refining of shale oil -- either alone or blended with petroleum -- will produce product slates whose performance characteristics are poorly known.

- Extent of denitrification required for refining may or may not be sufficient for environmentally acceptable end use. The relationship between combined nitrogen and NO_x emissions needs to be established to guide decisions about treatment severity.
- Relationships between product specifications and end-use performance are well (if empirically) known for petroleum products. Similar relationships must be developed for shale-oil or shale-oil-modified products.
- The extent of product upgrading which can best be performed at the retort site should be defined.

e. Environmental problems associated with shale oil upgrading and refining plants may differ in degree from those of petroleum refineries.

- Trace element contents are different. Some attention must be paid to species (such as arsenic) in effluents from shale oil refining.
- The organic products differ in various aspects from those of petroleum. Effects of these differences on employee health and safety and upon tolerable releases in plant effluents deserve study.

8.4.3 Materials research and development

The needed improvements in materials of construction for shale processing are of several kinds. Materials are needed with improved resistance to erosion and wear in handling abrasive solids, with improved resistance to corrosion by the aggressive liquids and gases, and with improved retention of valuable properties (especially strength properties) at higher temperatures. Coupled with the desired improvement in the material properties are needs for improved fabrication, joining, inspection and in-service repair methods.

a. Benefits could accrue from improved drilling materials and from more erosion and wear-resistant materials for mining and transportation equipment.

- Abrasion- and wear-resistant, wrought or cast steels or easily applied facing or cladding alloys are needed.
- Long-term studies should be directed to obtaining superior materials with minimal use of strategically critical elements.

b. Shale retorts, gasifiers and combustors would expose materials to complex reducing and oxidizing atmospheres containing corrosive agents at elevated temperatures in the presence of erosive and abrasive materials.

- Mechanisms of corrosive attack and metal failure (including embrittlement by hydrogen, stress corrosion phenomena, and creep-fatigue interactions) need better understanding.
- Influence of abrasion and erosion by shale minerals on processes such as those above needs further study.

8.4.4 Instruments and controls

The following are technology needs in the instrument area:

- a. Improved diagnostic instrumentation is needed to facilitate resource evaluation and assessment and for evaluation and control of retorting and gasification operations.
- b. Improved diagnostic techniques for down-hole logging to establish details concerning kerogen content, formation porosity and permeability, and hydrological features of the shales and surrounding strata.
- c. Improved instrumentation to define, with both temporal and spatial resolution, temperatures, gas velocities and compositions, concentrations and size ranges of solid particulates and oil droplets, and surface properties of the matrix during retorting operations.
- d. On-line instrumentation for monitoring shale feed and gas feed and for establishing, where pertinent, location of bed-gas interfaces.
- e. Mass-flow measurements over space and time for two-phase systems over a wide spectrum of solid (or liquid droplet) concentrations in gas under varied, though generally turbulent, flow conditions.
- f. On-line measurement of solid particle sizes as functions of space and time within the reaction zones and in product gases.
- g. On-line instrumentation to establish carbon content of spent shale particulates and agglomerates.

h. On-line monitoring of the chemical composition of product gases, including concentrations of trace elements (such as alkali metal compounds, Cd and Hg), of sulfur-containing species, and of particulate matter.

i. Knowledge of chemical composition (stable materials and free radicals) in gaseous and in dense phases during pyrolysis and gasification would be of great value.

8.4.5 Design and planning studies

These types of studies are needed to help guide and focus the laboratory and engineering scale research and development work.

a. Broadly based, unbiased, and consistent technoeconomic and institutional evaluations of developing technologies are needed to guide meaningful decisions as to which alternatives are most worthy of support.

b. Systems studies and model development are needed, particularly:

- * To integrate resource characteristics (including overburden properties and hydrology of environs) with optimal mine and process design and operation.
- * To establish economic, socioeconomic, and environmental aspects of large mining, processing, and transport operations.
- * To permit more dependable scaleup of processes defined by pilot operations.
- * To predict the dispersion and disposition of mine and process effluents in the environment.

c. Product distribution and transport networks need to be identified in the region of interest.

8.5 Health, Safety, and Environmental Research

The environmental assessment reported in Chapter 7 was based on paper studies and the consideration of present regulations. Other environmental, health and safety issues are likely to surface when in-depth research is carried out. Detailed analysis is required of shale mining, recovery processes and waste disposal.

Unfortunately, neither coal nor western oil shale technologies can be applied directly to resolve potential environmental, health and safety issues surrounding mining, retorting, waste disposal and stabilization for eastern shales. It is not necessary, however, to approach eastern shale de nova with respect to these issues. Initial emphasis must be placed on evaluating the transferability of information and approaches from coal and western shale to Devonian shale, thus allowing early identification of areas not requiring substantial resources (manpower or financial), and determination of those areas for which data cannot be transferred.

Currently, no large-scale facilities for retorting eastern shale exist, and the initial processing will be done by small bench-scale or PDU facilities. Initial screening studies, similar to those utilized for coal conversion materials and western oil shale materials, should be conducted to obtain a preliminary assessment of the biomedical and ecological effects associated with eastern shale development.

The underground mining of Chattanooga shale could involve health and safety problems which arise in coal and uranium mining. Research is required to define the extent of these problems and to devise strategies for dealing with them.

- Control of methane may be required in some locations to avert mine explosions.
- Control of particulates may be required to avoid black lung disease in miners.
- Control of radon and other radioactive species may be needed to avoid public and occupational overexposure.

The mine and aboveground piles of overburden and spent shale are potential sources of contamination of surface and groundwater. The unusually large amounts of material involved on a regional basis could, in the long term, lead to stricter regulation than is required for current smaller-scale mining. The identity and quantity of materials that can be leached must be known, and the extent of their migration in surface and subsurface waters must be established.

- A better understanding is needed of the mechanisms and the rates by which acidic species are formed and are leached from the solid materials.

- * The extent of migration of dissolved pollutants, both organic and inorganic through the formation or through soils, needs to be determined.
- * The extent to which these leached and migrating species contaminate useful aquifers and surface waters needs to be evaluated.
- * Studies need to be made to evaluate effects of these waste streams on sensitive species.
- * It will be necessary to develop and demonstrate effective methods for mitigation of the adverse effects of these pollutants.
- * The control of radioactive materials in the waste will have to be demonstrated.

The physiological effects of oil products and liquid and gaseous effluents on plant employees, the general public and regional ecosystems must be established, and means for monitoring the environment for deleterious materials need to be developed. It may be necessary to investigate the further processing of products to reduce their toxicity. The feasibility of vegetating surface piles of waste will have to be determined.

A significant effort is needed to evaluate and monitor the socioeconomic and institutional impacts of Chattanooga shale development.

- * Regional impact assessment methodologies should be developed to deal with interstate impacts, colocation of other extractive industries, industrial supply potential, land-use conflicts, population shifts, and cumulative impacts.
- * Institutional assessments should be initiated, especially with respect to federal, state, and local regulatory and statutory conflicts.
- * Assessments of the short-term, long-term, and postdevelopment impacts should be made.
- * Alternative methods for monitoring and mitigation of adverse effects should be evaluated and employed before large scale industrialization is begun.

8.6 References

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APPENDIX A

Chemical Analysis of Samples of Chattanooga Shale

Chemical analyses are reported from five core samples supplied by H. W. Leimer of Tennessee Technological University (TTU). The mineral analyses were performed by UCND (Table A.1) whereas C, H, N, and S were reported by TTU, 1981 (Table A.2). The cores were drilled in the Eastern Highland Rim province as indicated in Table A.3. Concentrations for all elements except uranium, silica, sulfur, mercury, arsenic, and selenium were determined with a direct-reading spectrograph with an inductively coupled argon plasma source. These values represent the elemental concentrations present in a leachate after the sample is treated with a hot, concentrated hydrofluoric and nitric acid leach. Table A.4 lists the weight percent of each sample that did not go into solution. Arsenic and selenium analyses were performed using atomic adsorption and also represent the hot-acid-soluble portion of the shale samples. Mercury values were obtained by an atomic adsorption method, however, the leach used for this method was a combination of sulfuric acid and hydrogen peroxide. Silicon dioxide (SiO_2) values were obtained utilizing a low energy neutron activation method and are total SiO_2 values for the samples. Sulfur values provided by H. W. Leimer (TTU, 1981) are total sulfur values determined using a Fisher Sulfur analyzer Model 475.

Uranium values listed in Table A.1 as 'U' were determined fluorometrically using fluorometry and represent the hot-acid-soluble uranium values. Interference by iron and manganese was minimized by solvent extraction. Uranium values listed as 'U-NT' in Table A-1 were determined by neutron activation analysis and are total uranium values. Organic carbon analyses were performed on selected samples and the results are listed in Table A.5.

Table A.1. Chattanooga shale analyses performed by UCCND

Sample No.	Type	U (ppm)	U-NT (ppm)	U/U- NT	Hg (ppm)	S10 ₂ (%)	Ag (ppm)	Al (%)	As (ppm)	B (ppm)	Ba (ppm)	Bc (ppm)	Ca (%)	Ce (ppm)	Co (ppm)	Cr (ppm)	Cu (ppm)	Fe (%)	Hf (ppm)	K (%)	La (ppm)
211465-101	G	39.58	32.5	1.2	0.19	55.96	<2	6.6	13.0	140	550	3	0.84	60	13	150	200	4.0	<15	2.6	78
211466-102		47.42	42.4	1.1	0.40	60.99	<2	7	9.0	120	470	3	0.3	78	36	100	120	5	<15	2.6	89
211467-103		45.48	45.8	0.99	0.27	54.75	<2	7	5.8	120	460	3	0.3	78	39	100	160	5	<15	2.9	85
211468-104		10.49	11.9	0.88	0.13	62.75	<2	9	6.2	150	570	3	0.8	96	17	110	86	3	<15	3.0	120
211469-105		9.84	9.82	1.0	0.24	62.35	<2	9	3.0	160	450	3	1.2	94	19	150	170	3	<15	3.1	110
211470-201		23.84	22.5	0.94	0.36	55.85	<2	3	1.8	63	190	1	0.4	35	11	59	94	2	<15	1.4	42
211471-202		10.13	10.3	0.98	0.20	59.56	<2	8	3.1	160	580	3	0.9	100	20	110	130	4	<15	2.9	120
211472-203		65.51	59.6	1.1	0.41	55.56	<2	7	6.4	110	430	4	0.2	78	40	98	170	5	<15	2.4	88
211473-204		41.16	40.2	1.0	0.33	60.13	<2	7	7.6	110	510	3	0.6	79	37	89	99	4	<15	2.5	92
211474-205		41.56	43.6	0.96	0.35	54.65	<2	6	17.0	110	350	3	1.6	78	17	120	160	4	<15	2.3	100
211475-301		81.87	92.1	0.89	0.20	49.06	<2	5	24.0	71	330	4	0.3	68	92	86	96	8	<15	1.9	81
211476-302		40.95	49.3	0.83	0.26	58.97	<2	6	11.0	110	410	3	0.3	71	38	97	110	5	<15	2.5	83
211477-303		76.48	75.2	1.0	0.30	52.13	<2	6	5.3	100	390	4	0.3	70	41	97	170	5	<15	2.2	80
211478-304		8.83	8.83	1.0	0.14	63.98	<2	9	3.6	150	550	3	0.6	91	16	120	99	3	<15	2.8	110
211479-305		42.13	42.2	1.00	0.40	52.88	<2	7	4.7	130	420	4	0.5	75	28	140	190	4	<15	2.4	91
211480-401		96.18	87.0	1.1	0.23	52.55	<2	5	22.0	63	360	4	0.3	69	61	96	110	7	<15	2.1	80
211481-402		44.45	51.0	0.87	0.16	62.70	<2	6	14.0	51	290	3	0.6	70	44	97	110	5	<15	2.4	80
211482-403		67.28	62.9	0.93	0.24	53.96	<2	6	12.0	110	400	4	0.4	72	46	130	190	5	<15	2.1	87
211483-404		6.82	7.35	0.94	0.42	63.16	<2	9	2.3	150	540	3	1.1	85	15	110	77	4	<15	2.8	96
211484-405		44.78	42.8	1.0	0.56	53.77	<2	7	5.9	130	430	4	0.8	70	30	150	220	5	<15	2.3	92
211485-501		98.99	86.3	1.1	0.37	49.74	<2	5	34.0	56	340	4	0.2	60	64	100	110	8	<15	2.1	78
211487-502		67.96	49.1	1.0	0.35	58.41	<2	5	13.0	86	390	3	1.2	74	41	110	120	5	<15	2.4	80
211488-503		71.59	69.1	1.0	0.16	54.14	<2	6	9.2	91	380	4	0.3	73	42	110	190	5	<15	2.3	78
211489-504		11.55	11.7	1.0	0.12	60.93	<2	8	2.4	150	500	3	0.6	87	110	110	110	3	<15	3.0	96
211490-505		43.18	45.1	0.96	0.24	53.63	<2	7	5.0	130	430	4	0.4	66	26	150	200	4	<15	2.4	89

Table A.1. Contd.

Sample No.	Type	Li (ppm)	Mg (%)	Mn (ppm)	Mo (ppm)	Na (%)	Nb (ppm)	Ni (ppm)	P (ppm)	Pb (ppm)	Sc (ppm)	Se (ppm)	Sr (ppm)	Th (ppm)	Ti (ppm)	V (ppm)	Y (ppm)	Zn (ppm)	Zr (ppm)
211465-101	G	54	0.91	160	110	0.31	<4	230	2,800	44	12	10.0	94	10	2,900	890	56	660	98
211466-102		47	0.9	190	120	0.4	<4	150	450	33	12	2.6	94	8	3,500	240	23	200	120
211467-103		52	0.9	200	120	0.4	<4	140	610	45	12	2.2	100	10	3,300	210	24	190	110
211468-104		50	1.5	410	15	0.4	5	79	460	32	15	1.0	130	15	4,100	170	24	110	130
211469-105		54	1.7	330	15	0.4	7	100	630	30	17	1.5	82	13	4,000	210	26	210	120
211470-201		26	0.6	140	41	0.2	<4	79	370	22	6	2.2	38	7	1,500	190	14	160	49
211471-202		56	1.5	360	23	0.5	5	100	490	35	18	1.6	130	13	4,100	260	26	180	130
211472-203		52	0.8	190	140	0.4	<4	94	650	55	12	3.0	95	13	3,100	220	25	190	100
211473-204		41	0.8	190	96	0.4	<4	94	500	43	12	1.9	110	11	3,400	220	22	180	110
211474-205		49	0.8	120	100	0.3	<4	150	5,000	34	11	5.9	130	8	2,900	390	52	600	100
211475-301		41	0.6	160	270	0.3	<4	130	1,100	95	9	3.8	60	6	2,500	250	36	650	89
211476-302		43	0.8	150	120	0.4	<4	160	420	36	11	2.6	75	10	3,200	230	22	170	110
211477-303		49	0.9	230	170	0.3	<4	400	510	49	11	3.6	81	6	2,800	240	28	210	94
211478-304		52	1.4	310	9	0.4	6	140	330	25	17	1.5	120	13	4,400	220	21	150	130
211479-305		55	1.1	290	170	0.3	<4	150	800	46	14	6.4	85	13	3,200	640	34	360	110
211480-401		38	0.7	170	220	0.3	<4	79	640	31	9	3.2	70	9	2,600	240	29	210	93
211481-402		34	0.7	160	140	0.4	<4	260	630	39	10	2.5	89	9	3,100	240	22	220	110
211482-403		45	0.9	260	150	0.3	<4	180	505	56	12	3.5	85	12	3,000	250	27	210	100
211483-404		47	1.4	460	5	0.4	8	160	310	27	16	1.2	130	9	3,900	190	19	130	120
211484-405		52	1.1	330	180	0.3	<4	170	890	32	14	6.4	91	13	3,400	640	34	360	110
211485-501		40	0.7	150	230	0.3	<4	61	620	35	9	3.2	56	8	2,600	220	30	180	90
211487-502		36	0.7	190	150	0.4	<4	290	750	36	10	2.1	92	8	3,000	200	24	180	110
211488-503		47	0.8	170	180	0.3	<4	160	650	51	11	3.9	82	7	2,600	240	27	220	93
211489-504		50	1.4	330	23	0.4	5	140	370	23	16	1.9	110	9	3,700	150	21	190	120
211490-505		50	1.1	260	180	0.3	<4	160	660	52	14	6.7	81	13	3,500	730	32	420	110

Table A.2. Analyses of Chattanooga shale samples reported by Tennessee Technological University (1981)

Sample No.	% C ^a	% H	% N	% S
211465-101	15.3	1.58	0.45	3.1
211466-102	8.14	1.03	0.28	3.5
211467-103	11.55	1.29	0.36	4.1
211468-104	2.15	0.53	0.14	1.6
211469-105	4.82	0.74	0.20	1.8
211470-201	12.68	1.31	0.38	4.4
211471-202	7.44	0.99	0.29	4.0
211472-203	13.08	1.56	0.22	4.5
211473-204	3.67	0.80	0.19	1.5
211474-205	9.10	1.26	0.32	3.0
211475-301	16.45	1.71	0.54	8.4
211476-302	9.00	1.14	0.35	4.0
211477-303	16.55	1.77	0.50	4.4
211478-304	1.77	0.63	0.17	1.1
211479-305	12.70	1.34	0.45	3.3
211480-401	13.12	1.25	0.46	7.7
211481-402	9.45	0.97	0.31	4.5
211482-403	14.89	1.52	0.49	4.5
211483-404	1.52	0.56	0.17	1.5
211484-405	11.80	1.38	0.42	3.3
211485-501	14.55	1.47	0.45	7.0
211487-502	8.71	1.01	0.28	4.8
211488-503	15.50	1.60	0.82	4.4
211489-504	2.78	0.66	0.43	2.1
211490-505	12.07	1.47	0.45	3.8

^aOrganic carbon.

Table A.3. Source of Chattanooga shale samples

County	Location		Sample No. ^a
	Latitude	Longitude	
Putnam	36°12'28"	85°34'41"	211465-101
			211466-102
			211467-103
			211468-104
			211469-105
Putnam	36°04'59"	85°36'29"	211470-201
			211471-202
			211472-203
			211473-204
			211474-205
White	35°55'35"	85°37'56"	211475-301
			211476-302
			211477-303
			211478-304
			211479-305
Warren	35°45'33"	85°53'59"	211480-401
			211481-402
			211482-403
			211483-404
			211484-405
DeKalb	35°54'54"	85°49'50"	211485-501
			211487-502
			211488-503
			211489-504
			211490-505

^aIn each sequence, the first sample is from the upper Gassaway, the second from the middle Gassaway, the third from the lower Gassaway, the fourth from the upper Dowlletown and the fifth from the lower Dowlletown.

Table A.4. Weight percent of
Chattanooga shale samples
undissolved by disso-
lution process

Sample No.	Weight percent undissolved
211465-101	14
211466-102	10
211467-103	11
211468-104	3
211469-105	6
211470-201	11
211471-202	4
211472-203	12
211473-204	10
211474-205	14
211475-301	7
211476-302	10
211477-303	16
211478-304	2
211479-305	15
211480-401	16
211481-402	12
211482-403	19
211483-404	2
211484-405	14
211485-501	19
211487-502	12
211488-503	18
211489-504	4
211490-505	14

Table A.5. Carbon analyses of selected samples
(Performed by UCCND)

Sample No.	% organic carbon in raw shale	% total carbon in raw shale	% inorganic carbon in raw shale
211466-102	9.1 (8.14) ^a	9.9	0.8
211477-303	17.4 (16.55)	18.0	0.6
211482-403	16.7 (14.89)	17.6	0.9
211488-503	16.6 (15.50)	17.5	0.9

^aResults in parenthesis were reported by Tennessee Technological University, 1981.

APPENDIX B

Detailed Material Balance Data

This appendix contains detailed mass and energy balance data for the hydroretorting experiments that are discussed in Chap. 5. Table B.1 shows measured and adjusted data for the ORNL experiments in which nominally one pound batches of Chattanooga shale were heated in a hydrogen atmosphere. Table B.2 shows measured and adjusted data for the IGT process development unit experiment 80 PDU-2 with New Albany shale.

Table B.2. Computed material balance for IGT hydroretort test 80 PDU-2 with New Albany shale.^a

	Mass per unit mass of raw shale							HHV ^b
	C	H	S	O	N	Ash	Total	
Feed								
Shale	0.1805	0.1852	0.0495	0.1011	0.0564	0.7362	1.3089	10400
Gas	0.1377	0.0170	0.0495	0.0545	0.0051	0.7362	1.0000	2700 ^c
N ₂	0.0428	0.1682		0.0466	0.0513		0.3089	10700
O ₂					0.0513		0.0513	
CO	0.0255			0.0100			0.0100	
CO ₂	0.0010			0.0339			0.0594	260
H ₂		0.1627		0.0027			0.0037	
CH ₄	0.0163	0.0055					0.1627	9920
							0.0216	520
Product								
Shale	0.1573	0.1905	0.0367	0.1240	0.0552	0.7383	1.3021	13030
Oil	0.0338	0.0017	0.0281	0.0056	0.0014	0.7383	0.8090	650
Gas	0.0548	0.0065	0.0008	0.0015	0.0006		0.0642	1130
N ₂	0.0687	0.1714	0.0078	0.0800	0.0532		0.3311	11250
CO	0.0184				0.0532		0.0532	
CO ₂	0.0020			0.0246			0.0430	190
H ₂		0.1563		0.0054			0.0074	
CH ₄	0.0353	0.0119					0.1563	9530
C ₂ -C ₄	0.0130	0.0027					0.0472	1130
H ₂ S		0.0005	0.0078				0.0157	340
Water		0.0109		0.0869			0.0083	60
							0.0878	
Prod/feed	0.871	1.029	0.741	1.227	0.979	1.003	0.995	0.97
Adjusted data ^d								
H ₂ O		0.0074		0.0590			0.0664	
NH ₃		0.0003					0.0015	15
H ₂ S		0.0008	0.0118		0.0012		0.0126	90
C ₆ H ₆ O	0.0196	0.0016		0.004			0.0256	310
Aqueous	0.0196	0.0102	0.0118	0.0634	0.0012		0.1061	415
Product	0.1769	0.1898	0.0485	0.1005	0.0564	0.7383	1.3104	10440
Prod/feed	0.980	1.025	0.980	0.994	1.000	1.003	1.001	1.000

^aTest data reported in DOE/ET 14102-1. Retort pressure 406 psig. Average bed temperature 537°F (stage 1) and 1224°F (stage 2). Maximum bed temperature 810°F (stage 1) and 1355° (stage 2). Shale space velocity 123 lb/ft³/h (stage 1) and 121 lb/ft³/h (stage 2) bed depth 10 ft in both stages.

^bHigher heating value in Btu/lb.

^cEstimated -- not reported in test data.

^dAqueous phase adjusted by adding ammonia, hydrogen sulfide and phenol to partially reconcile the elemental material balances.

APPENDIX C

Metal Prices and Potential Yields

A summary is presented (Table C.1) of metal prices and potential yields from processing 10^5 tons of Chattanooga shale per day. It is seen that such an operation could produce a significant percentage of the current U.S. consumption of Al, Cb, Co, Mo, and U, and more than the current consumption of vanadium. The elements that could produce the largest reserves in terms of current prices are Al, Fe, Mo, Co, and U.

Since it is assumed that a composite mixed oxide concentrate would be supplied to an industrial metal recovery plant, 50% of the market price of the metals was used in estimating the value of the recovered trace elements. This is approximately the cost fraction that can be attributed to hydrometallurgy in the overall costs for recovering the various trace metals.

Elemental content of mined shale^a

Element	Marketable form	Grade/purity	(\$/lb)	Concentration in shale ^b	Fractional recovery by acid leaching ^c	ton/year	Percent of annual U.S. consumption ^d	Value at listed prices (\$ 10 ³)
Al	Synthetic Bauxite	>87-88% Al ₂ O ₃	200-225 ^{e,f}	6%	0.77	1.52 x 10 ⁵	25	651
Cb	Synthetic Columbite	>65% Cb ₂ O ₅	10-12 ^{g,h}	200 ppm	0.90 ⁱ	594	20	29
	Columbium Pentoxide	89-97% Cb ₂ O ₅	^j					
Co	Cobalt Oxide	Metallurgical grade 75-76% Co	21.11 ^k	60 ppm	1.00	1.98 x 10 ³	22	111
Cr	Chroma Oxide (chromite), Transvaal	Dry basis		100 ppm	0.84	2.77 x 10 ³	0.5	0.5
		44% Cr ₂ O ₃	49-53 ^{g,h}					
		48% Cr ₂ O ₃	110					
Fe	Iron Oxide (Feed suitable for direct reduction)	53-64% Fe	>50 ^{e,l}	6%	0.99	1.95 x 10 ⁵	2	155
		(<2% SiO ₂ , <2% Al ₂ O ₃)						
Mn	Manganese Dioxide	Natural African grade, 70-76% MnO ₂	115 ^{e,k}	350 ppm	0.92	1.06 x 10 ⁴	2	2
Mo	Molybdenum Trioxide	Metallurgical grade, >99.9% MoO ₃	7.50 ^k	200 ppm	0.98	6.47 x 10 ³	19	146
Ni	Nickel Oxide	75-78% Ni	2.00 ^k	200 ppm	0.97	6.40 x 10 ³	4	34
V	Vanadium Pentoxide	Technical grade	3.55 ^m	300 ppm	0.96	9.50 x 10 ³	141	67
U	Uranium Oxide	Reactor grade U ₃ O ₈	25 ⁿ	65 ppm	0.62	1.76 x 10 ³	14 ^o	103

^aAssume: 100,000 tons of shale mined/day - 330 d/year of operation.

^bTable 7 - Concentration column - Chattanooga Shale - A Valuable U.S. Resource, M. D. Silverman, ORNL/OR 80-237 (July 21, 1980).

^cTable 6 - Hydroretorted shale, 500°C - Ibid.

^dFrom various Mineral Industries Surveys, Bureau of Mines, U.S. Department of the Interior.

^ePrice/short ton.

^fPersonal communication with Jac T. Saltzgiver, Aluminum Co. of America, May 1980.

^gPer pound of contained pentoxide.

^hEngineering and Mining Journal, September 1980.

ⁱAssumed recovery fraction in processing. Experimental results not available. This value may be much too high since columbium and tantalum oxides are difficult to dissolve.

^jMarket price not available.

^kChemical Marketing Reporter, November 1980.

^lPersonal communication with Donald Dury, Commodity Specialist, Bureau of Mines.

^mPer pound of contained vanadium.

ⁿAmerican Metal Market, March 23, 1981 (as quoted by Nuclear Exchange Corp.).

^o"Statistical Data of Uranium," GSO-100(81), Department of Energy (in press).

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