APPENDIX E ENVIRONMENTAL COSTS

A. INTRODUCTION

This appendix sets forth the rationale and the calculational procedures used in developing the environmental costs associated with the decision analysis of Chapters V and VI. The compliance costs for pollution control which are directly tasked to the project (those costs which are internalized), are presented in the first section, while estimates of the costs associated with environmental externalities (those costs which are external to the project) are discussed in the second section.

Determining or estimating the overall environmental compliance costs arising from a new energy technology is, under the best of circumstances, difficult. For this analysis, the degree of difficulty has been significantly increased, since an attempt has been made to encompass and price out all of the external environmental costs.

It should be noted that compliance costs and externalities are not unrelated since in some cases the externalities can be reduced by using a more effective, more expensive control technology, in turn resulting in a higher internal cost. For example, if sulfur oxides are found to cause environmental damage at a rate equivalent to 25 cents per pound of sulfur oxide emitted instead of the nominal estimate of 10 cents, improved scrubber technologies may be used to reduce sulfur emissions. These technologies will add to the economic cost of synthetic fuels but, on balance, would reduce the total of economic and social costs.

All quantitative estimates in this Appendix represent state-of-the-art expected values and have differing levels of uncertainity associated with them. Testing of these expected values and variances is an integral part of the synthetic fuels program. Obtaining actual test data is one of the reasons for implementing the program. Current and contemplated environmental studies prior to design and construction are intended to extend understanding to a level yielding sufficient confidence to proceed with the commercialization program. The learning experience would then provide data for rational decision concerning extension to higher production levels in the near-term.

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B. COSTS OF COMPLIANCE

1. Oil Shale Development

The pollution levels and cost estimates contained herein are for a prototype 50,000 bbl/day plant. Available data was obtained primarily from the Project Independence Reports, Council on Environmental Quality/ Environmental Protection Agency (CEQ/EPA) studies on environmental coefficients and from the draft Environmental Impact Statement (EIS) for the synthetic fuels program. As one would expect with a new technology, available data is sparse and much of the cost estimates shown are based on informed judgments on the level of pollution loadings and the cost of technology control.

a. Water

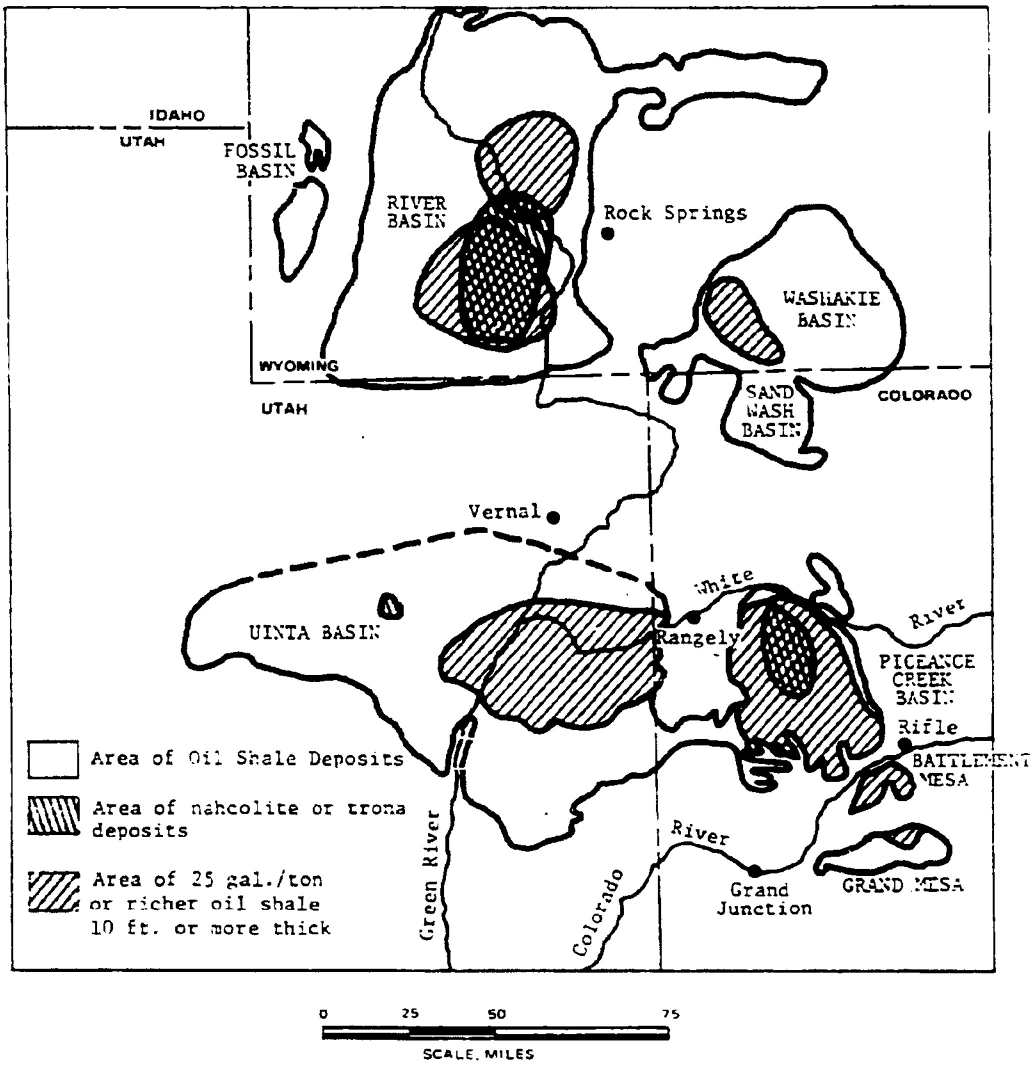
It is assumed that water usage in the oil shale plant is a closed system where water introduced into the system is reused after being chemically and physically treated for removal of pollutants. Thus, there will be no water discharge from the shale plant. The cost of this system is considered as an environmental cost since the closed water consumption system is a direct result of environmental requirements. Some cost data for treatment of waste water from an In Situ plant is available.1/ For this analysis, it was assumed that these costs are representative of surface shale recovery.

For a 50,000 bbl/day plant, the capital cost of waste water treatment (ammonia and sulfur removal) is estimated at $9.2 million for a plant which uses ground water for supply and discharges no effluents to the Colorado River.2/

However, there may exist an additional "outside the gate" environmental cost resulting from the possible need to offset potential increased salinity downstream of the Colorado River due to oil shale development (a more complete discussion is included in externalities section). Great concern and a sense of urgency in halting the increase in salinity have been expressed by those who depend upon the river as a lifeline. The salinity control problem extends to the Republic of Mexico and has become an important aspect in our international relations with that nation. The salinity problem of the lower Colorado River may be aggravated by the increased consumption of the relatively low-salinity waters of the Upper Colorado River basin.

1/ Hittman Associates Report 593, Volume 2.

2/ The withdrawal of ground water would be used to satisfy the initial needs for water in the Colorado River basin. However, the availability of ground water would be continuously decreasing in Colorado, causing more dependence on surface water. Water availability in the Rocky Mountain area is an important long-term constraint on accelerated oil shale development.



OIL SHALE AREAS IN COLORADO, UTAH, AND WYOMING

It is possible that oil shale production may contribute to the salinity problem by the removal of clean surface water and decreased dilution of the dissolved solids already present. This is a problem that is not indigenious to shale oil production alone, but is the result of the consumption of water, for any reason, from the Upper Colorado River.

On the other hand, it is possible that shale oil production may actually decrease the salinity of the Colorado River through discharging high quality ground water in connection with shale mining. If the saline content of the aquifers in the Upper Colorado basin is greater than that of the Colorado River, drawing off this aquifer water for use in shale oil processing could actually reduce the salinity of the Lower Colorado River. It is not clear at this time which of these two possible effects would be predominate.

b. Air Quality Constraints

The estimated capital costs for retort air quality control (hydrogen sulfide removal) are $7.4 million. However, there is an additional cost resulting from boiler air quality requirements (SO_2 removal). These costs have been estimated at $13-$18 million given the 1980 Colorado Air Standard of 10 ug/m^3 for $SO_{(x)}$. This brings the total capital costs for air quality control to $20-$25 million.

As noted in the draft Environmental Impact Statement (EIS) for Synthetic Fuels Commercialization Program, imposition of the stringent Colorado air standards may limit oil shale development in the Piceance basin to a level of about 200,000 bbls/day.

c. Solid Waste

Spent shale will average about 85,000 tons/day with a volume 25-35% greater than the oil shale in its original state. Approximately 75 acres/ year are required to dispose of the spent shale. A disposal site to store the overburden will be required of 500 acres. Since some initial treatment of the solid waste may be required before disposal, predisposal facilities may be necessary. Cost estimate for all of the above processes will be approximately $20 million.

d. Transportation Costs

The spent shale will have to be transported to a disposal site. It is assumed that for environmental reasons the disposal site will differ from a site otherwise chosen to minimize costs; i.e., the spent shale may be disposed of in a box canyon, rather than on a flat area right next to the plant. Disposal in a box canyon would be environmentally beneficial in that fewer acres of land would be required for disposal purposes since the shale could be piled vertically, and because the vertical formations may be constructed so as to minimize the potential leaching problem.

e. Land Reclamation

Besides the 75 acres/year required for spent shale disposal, - -ximately 25 acres/year will be disturbed by mining of the oil shale. ... .tion is estimated to cost $2,500/acre plus three acre feet of ... per acre of land disturbed. Assuming a cost for water of $50/acre foot, the total cost will be:

$$100 \times 2{,}500 + 50 \times 600 = \$280{,}000/\text{year}$$

C. UTILITY FUEL/SYNTHETIC CRUDE

Water Treatment - $2.2 million

Air Treatment (Sulfur Removal) - $2.4 million

Total (Factor 1.3) - $6.0 million

Solid waste and land reclamation costs are assumed to be the same as for oil shale except that the reclamation cost/acre will be about $2,000. However, less land will be disturbed by the mining of coal or by solid waste disposal (about 85 acres/year).

D. HIGH BTU GAS

Water Treatment - $2.4 million

Air Treatment (FGD) - $9.8 million

Total (Factor 1.3) - $16 million

Solid waste, land reclamation, and leaching - same as for synthetic crude.

E. COST OF EXTERNALITIES

Quantitative analysis of decisions should include a numerical evaluation of the consequences of each decision alternative. The evaluation may be difficult to perform, because (1) there may be considerable uncertainty about the level of consequences that will occur, and (2) it is often difficult to assess how society might value one set of consequences as opposed to another. Nonetheless, the necessity to make decisions forces those responsible in the policy process, in both the executive and legislative branches of government, to make judgments, implicitly if not explicitly. The goal of the analysis should be to give insight to the responsible policy makers by putting into perspective the array of complex issues involved in the decision.

Allowable emissions of air pollutants, water pollutants, solid waste, and disturbance to land are social consequences of energy development that occur outside the economic system as it is usually viewed, and economists often refer to them as externalities. Whereas the cost of raw materials and labor needed to produce oil from shale are reflected in the price of the product, the damage to material property and degradation of human health that result from sulfur oxide emissions from an oil shale plant will not be reflected in the price. More effective control technologies may be imposed that will reduce the amount of emissions per unit of product produced, but the added cost of these technologies will be reflected in an increase in the cost of the product. Imposing a control technology causes the externality to be reduced and replaced by an internalized cost. With the usual assumption of cost benefit analysis that it is the total of benefits less costs that serve as the decision criterion (and not the distribution of benefits and costs among various individuals or groups), it is clear that decisions to impose additional control are desirable when the reduction in costs associated with the emissions eliminated is larger than the control cost needed to eliminate them.

A synthetic fuel may differ from other synthetic fuels and from natural energy materials in both economic costs and externalities, that is, the non-priced social consequences that are imposed upon society. A decision criterion should include these externalities by expanding the economic price of a synthetic fuel product to include the costs ascribed to the environmental externalities that will result from its production.

For the purpose of the decision analysis described in the main body of this report we have attempted to evaluate the important externalities associated with synthetic fuel production, and to use the social price as the criterion for government decision. The evaluation was carried out using emissions data from the Synthetic Fuel Commercialization Program, Draft Environmental Impact Analysis, other available sources and such methodology, models, or subjective judgment as was available to the authors.

While the values for the external costs associated with environmental effects of synthetic fuel are not found to be of critical importance (see the sensitivity analysis in Chapter VI and Appendix I, it should be noted that basis for calculating these values is quite modest, and that additional information will undoubtedly lead to some revision of the numbers. The analysis presented here is intended as a summary, based on the information presently available, of the importance of environmental factors in the synthetic fuels program decision. It is hoped that dissenting or supportive viewpoints that may be put forth during the review and policy decision process will address the issues in similar quantitative fashion.

As the basis for the assessment, two plants will be examined, an oil shale plant complex and a high Btu fixed bed coal gasification plant. Similar assessments can be carried out for other synthetic fuel plants based on data in the Draft Environmental Impact Analysis (EIA). For purposes of obtaining a rough assessment of the cost of environmental externalities these two processes would appear to be adequately representative.

1. Evaluation of Externalities Associated With an Oil Shale Mining and Processing Facility

A unit oil shale complex producing 50,000 barrels per day of synthetic crude oil will be taken as the first representative synthetic fuel plant. While specific assumptions do not appear to be crucial, conventional mining and surface processing as represented by the TOSCO II process has been used as the model for this assessment. Other processes in general appear to have lower environmental costs, with the possible exception of ground water contamination, as discussed below.

a. Air Emissions

Sulfur oxide and nitrogen oxide emissions would appear to be the most significant emissions. Emission estimates given in the Draft EIA for sulfur dioxide are 5380 tons/year for a surface process and 8406 tons/year for an in-situ process; for nitrogen oxides, 1655 tons/year for a surface process and 2256 tons/year for an in-situ process (Draft EIA, Tables IV-55 and 56, page IV-102 and 103). The sulfur oxide levels are based on compliance with the Colorado emission standards. The estimates given by Colony Development Operation in their Environmental Impact Analysis (EIA) for their proposed Parachute Creek Complex give maximum estimates for emission rates of sulfur oxides and nitrogen oxides (Colony EIA, Part One, Table 84, page 292). If these maximum estimates given in lbs/hour are translated in to annual emissions (tons/year) assuming continuous operation at the given emission rates, estimates are obtained of 7730 tons/year of sulfur dioxide and 27,300 tons of nitrogen oxide. The latter estimate is approximately 15 times the government figure, which is apparently an estimate for direct combustion retorts extrapolated from industrial boiler experience (Draft EIA, page IV-101). Although the Colony figures will be used, it should be noted that these represent worst case estimates. Unpublished data received from Colony indicates that the actual emissions could average substantially less than these maximum values, by a factor of four.

To evaluate sulfur oxide emissions, the data and analysis in the National Academy Report, Air Quality and Stationary Source Emission Control will be used. This report calculates damages from sulfur dioxide and sulfates formed from SO_2 for the Northeastern U.S., however, the damage estimates for rurally located plants of 10 cents per pound of sulfur dioxide (21 cents per pound of sulfur) may be taken as a reasonable estimate for the more sparsely settled West. The sensitivity range of 2.5 to 25 cents per pound is somewhat broader than used in the Academy Report. Health effects such as chronic respiratory disease and aggravation of heart-lung disease symptoms and property damage to galvanized steel and other materials provide the leading terms in this evaluation. Acid rain and visibility reduction are also included; the latter effect may be particularly important for scenic rural areas in the Western U.S. (Randall et al., 1974).

For nitrogen oxide emissions no detailed evaluation models are available; however, the estimate of damages resulting from NO_x emissions (from the National Academy Report, Air Quality and Automobile Emission Control, Volume 4) over the estimated 44×10^9 lbs. of NO_x emitted annually, can be prorated. Taking an estimate of 3000 premature deaths at $300,000 per fatality and $300 million for property damage caused by nitrogen oxides (and ozone), we obtain an estimate of about $1.2 billion per year or about two cents per pound of NO_x. Acid rain and visibility effects may add on the order of one cent additional, assuming the contributions of SO_x and NO_x to be roughly comparable. A nominal estimate for the environmental damage caused by NO_x of three cents per pound emitted will be taken with a range for sensitivity analysis of 1-10 cents/lb.

Other emissions resulting from oil shale processing include carbon monoxide, hydrocarbons, and particulates, and perhaps some trace elements (Colony EIA, page 293, and Draft EIA, Tables IV-55, page 102). Included in the hydrocarbons may be small quantities of polycyclic hydrocarbons. Studies have shown (Smith-Collerus, 1974) that polycyclic hydrocarbons are present in the spent shale, but the amount of the potentially carcinogenic components appears to be of comparable order of magnitude as that contained in salads or smoked meats. While further studies are underway to assess the effect of polycyclic hydrocarbons and other pollutants, the damages from these emissions should be considerably less than for sulfur and nitrogen oxides. Therefore, no environmental costs have been ascribed to these pollutants.

b. Water Availability

Oil shale plants and other energy facilities will require large amounts of water, and in the arid West withdrawal of water from major rivers such as the Colorado may result in increased salinity downstream. Estimates of water use for oil shale plants are given in the Draft EIS (Table IV-58, page IV-107) as 6700-10,600 acre-feet per year, including needs for power generation and associated population. A slightly higher estimate of 11,800 acre-feet/year was given recently by an Atlantic Richfield Company representative (Rothfield, 1975). An estimate of 8300 acre-feet/year shall be used. It should be noted that water from shale retorting and shale oil upgrading may permit reductions in water use, and large quantities of ground water may be produced in mining shale in Colorado (Final Environmental Statement for the Prototype Oil Shale Leasing Program, Volume 1, pages III-34 and 45).

Evaluation of the damage caused by salinity increases in the Colorado River have been carried out by EPA and others. Using the result of $67,000 per milligram per liter of total dissolved solids quoted in the Final Environmental Statement for the Prototype Oil Shale Leasing Program (Volume I, Chapter III, page III-76), an estimate of $5 damages per acre-feet withdrawn can be computed. Considering the importance of Colorado River salinity to U.S. relations with Mexico and the future of the Lower Colorado River area, it is suspected that the $67,000 figure is low. Therefore, a nominal estimate of $20 per acre-foot of water withdrawn annually will be used, with a range of up to $50 per acre-foot withdrawn.

While the production process may be able to utilize water from aquifers, the available quantity of such water is unknown. It may be sufficient only to support the first few plants constructed in the Piceance Creek basin. Additionally, the dynamic nature and growth of an expanding oil shale industry would introduce additional demands on water. Oil shale development would stimulate water needs not only in the process requirements, but also in the secondary sense as communities develop to support the oil shale industry. In turn, this would create competition between water for oil shale development and that utilized for public services, agricultural, recreation, and other industrial users. Therefore, the range appropriate for ground water depletion may be somewhat broader. In some areas in the Piceance basin, excess water of high quality may actually be generated from mining, and this water might be discharged to augment local streams. However, over time the salinity of excess mine water may increase, and the effect of depleting ground water may be to dry up local springs and stream sources. (Final Environmental Statement for the Prototype Oil Shale Leasing Program, Volume I, pages III-45-71). An approximate range of $0-$300 per acre-foot will be taken as the alternative use value of ground water for purposes of sensitivity analysis. The $300 value is based on the cost required to transport water from outside the basin.

c. Water Qualtiy

While leaching of spent shale stored on the surface is possible, it seems highly unlikely that such leaching would significantly increase salinity in downstream areas. Both processing and storage of spent shale will be designed to have zero discharge. Calculations in the Final Environmental Statement for the Prototype Oil Shale Leasing Program, indicates that neither pile slippages, flash floods, or catchment basin failures should be regarded as major causes of salinity increases. Therefore, a range of 0¢-3¢ per barrel of shale oil produced will be used for surface water degradation, with one cent per barrel as a nominal estimate.

Ground water contamination poses a possibly more serious problem in the Piceance basin. The upper oil shale zone is a high quality aquifer, while the lower leached zone is a saline aquifer. A possibly serious issue could be leaching from in-situ processed shale in the upper quifer. To account for this problem a range of 0¢-20¢ per barrel of shale oil as a highly subjective estimate of potential damages for ground water degradation will be used, with a nominal value of one cent per barrel

d. Land Surface Alteration

Estimates of land required for spent shale disposal are approximately 75 acres per year, and approximately 25 acres per year additional are disturbed by surface mining development. Facilities for the shale oil complex will require about 850 acres over the life of the mining operation, including 500 acres for disposal of overburden (Draft EIA, Table IV-57, page IV-104 and Final Environmental Statement for the Prototype Oil Shale Leasing Program, Volume I, page III-12).

Externalities associated with land disruption include loss of productive use, effects on vegetation and fauna, including any endangered species in the area, impact on recreational uses (e.g., deer hunting in the Piceance basin), aesthetic and visual impact. A highly subjective estimate for these damages is $100-$10,000 per acre disturbed with $1,000/acre as a nominal estimate. In acreage dedicated to the shale complex for the life of the plant, values of one-tenth the estimates given above will be used (a one-time cost of $1,000 per acre is equivalent to $100 per acre each year with a discount rate of 10%).

e. Summary

The magnitude of the effects and the evaluation measures given above are sufficient to compute dollar costs for the environmental externalities. These may be placed on a per barrel by prorating them over the 18.25 million barrels per year produced by a 50,000 bbl/day capacity plant. A summary of the resulting values is given in Table E-1. Sensitivity limits for the

TABLE E-1

ENVIRONMENTAL COST OF OIL SHALE: SUMMARY

(Cents Per Barrel)

Externality: Cause of Social Consequences	Cost Assumptions Low	Nominal	High
Sulfur oxide emissions (7730 tons/year-Colony estimate)	1	8	21
Nitrogen oxide emissions (27,300 tons/year-Colony estimate)	3	9	30
Water Depletion (8,300 acre-feet/year)	0	1	13
Water Quality			
Surface water degradation	0	1	3
Ground water degradation	0	1	20
Land Surface Alteration (115 acres/year, 850 acres dedicated to facility for plant lifetime)	0.1	1	11
Total[1] Cost of Environmental Externalities	12	21	56

1/ Totals for high and low cases are computed by taking the square root of the sum of the squares of differences from the nominal value.

environmental costs are calculated from the square root of the sum of the squares of the deviations from the nominal values, as is standard in error propogation analysis. It should be noted that the nominal value is dominated by the sulfur oxide and nitrogen oxide terms. The high estimates include major contributions from (ground) water depletion, ground water quality, and land surface alteration. Mitigating strategies should exist such that these categories of environmental damage may be reduced if the cost ascribed to them is high.

2. Evaluation of Externalities Associated With a High Btu Coal Gasification Plant

A representative coal gasification fixed bed plant producing 250 mmscf/day of 1,000 Btu/CF gas will be used for this analysis. Power River coal is assumed as the feedstock. Emission estimates for a stream factor of 91% are contained in the Draft EIA. The plant produces approximately the energy equivalent of 45,000 barrels per day of crude on 91% of the days in the year for a toal production of 14.9 million barrels per year, equivalent to an average output of 40,000 barrels per day on a continuous basis. Coal requirements are 8.3 million tons per year of 16.6 million Btu/ton Power River coal.

a. Air Emissions

An estimate of 14,000 tons of sulfur oxide and 12,100 tons of nitrogen oxides per year are given for the high Btu gas plant (Draft EIA, Table IV-5, page IV-12). The basis for evaluating these emissions is the same as described for oil shale above. As with oil shale, the damages from other air emissions are assumed to be negligible when compared to those from sulfur and nitrogen oxides.

Studies are underway to ascertain whether this conclusion is valid in view of the presence of polyclyclic hydrocarbons and volatile trace elements in the coal such as, mercury, selenium and florine.

b. Water Availability

The Draft EIA gives an estimate for water consumption by the plant of 3,520-21,070 acre-feet per year (Draft EIA, Table IV-11, page IV-28). Additional waste needs of 13,000 acre-feet per year during construction and 3,853 acre-feet per year during operations are given in Table IV-19, page IV-48. Table V-4, page V-7, gives an estimate of 10,663 acre-feet annually of which 320 would be "used." Thus, there is a total estimate for water requirements, including any needs for offsite power generation and associated populations, of 21,000 acre-feet per year. Evaluation of water withdrawals is made on the same basis as for oil shale: a nominal social cost of $20 per acre-foot withdrawn, and a sensitivity range of $0-$300 per acre-foot.

c. Water Quality

It is assumed (Draft EIA, Tables IV-12 and V-5, pages IV-30 and V-9) that both mining and processing will be carried out such that zero discharge is allowed beyond the site boundary. Process water and impounded runoff will be treated and used for cooling tower water makeup. All blowdown streams are collected and sent to lined evaporative ponds for disposal. Acid drainage is not a serious problem for low sulfur western coal deposits. Sedimentation should likewise be almost entirely preventable with good mining and reclamation practices. Some sedimentation may occur from surface mined areas until revegetation occurs. In arid areas revegetation takes longer, but then siltation should not pose a problem except possibly for flash floods.

A range of one cent to 50 cents per ton of coal mined will be used as the range for surface water degradation from mining and processing activities, with 10 cents per ton as a nominal estimate.

Disturbance of ground water may present a potential problem because western coal seams are often the aquifers that provide ground water supplies for livestock and other uses. Mining operations could degrade water quality with adverse effects on local water supplies. As with shale, quantitative assessments on the extent of this problem are not available. Therefore, a highly subjective assessment of one cent to 50 cents per ton of coal mined (nominal estimate: three cents/ton) for the social cost of ground water degradation is assumed.

d. Land Surface Alteration

The costs of rehabilitation and revegetation are included in the economic cost of productive control. Cost estimates range from \$50-\$4,000 (Grim and Hill 1974, Packer 1974, NAS, Rehabilitation Potential of Western Coal Lands, 1974). With the thick coal seams characteristic of Western areas, only an estimated 61 acres per year will be disturbed by surface mining (Draft EIA, Table V-6, page V-13.). Plant acreage requirements are estimated at 350-900 acres. Evaluation of disturbed land is carried out on the same basis as for oil shale: \$100-\$10,000 per acre, with a nominal estimate of \$1,000 per acre. The valuation of land committed to plant facilities is taken as previously to be one-tenth as much.

e. Summary

As with oil shale one may compute a total environmental cost per barrel equivalent from the assumptions given above. The results are summarized in Table E-2. It can be seen that the estimates of environmental costs are somewhat higher than for the oil shale plant, as a consequence of the higher levels of sulfur oxide emissions and estimated water quality effects. These numbers should be taken as rough estimates: it is not at all clear that water quality effects are as large as reflected in these numbers. As with oil shale, if environmental costs are assessed to be large, mitigating strateg s may be desirable, and these may reduce the sum of economic and env. nmental costs for high Btu synthetic gas production.

TABLE E-2

ENVIRONMENTAL COST FOR A HIGH BTU FIXED BED GAS PLANT
250 MMSCFD (40,000 BBL/DAY, POWDER RIVER COAL

(Costs in ¢/Barrel Equivalent)

Category	Social Low	Cost Nominal	Asumptions High
Sulfur oxide emissions (14,000 tons SO_x/year)	5¢	19¢	47¢
Nitrogen oxide emissions (12,100 tons NO_x/year)	2	5	16
Water depletion 21,000 acre-feet/year	0	3	42
Water quality (ground and surface)	1	11	56
Land surface alteration (61 acres a year mined plus 650 acres for plant facilities)	0.1	1	8
Total[1/] Cost of Environmental Externalities	21	39	106

1/ Totals for high and low cases are computed by taking the square root of the sum of the square of differences from the nominal value.

F. HEALTH AND SAFETY

The risks to health and safety from synthetic fuel production appear to be largely occupational hazards to miners rather than risks to the general public. Underground mining has generally been a hazardous occupation, and shale mining will involve vast tonnage of material. Assuming productivity rates for shale mining and accident rates comparable to recent coal experience leads to a rough estimate of 10 cents per ton of shale mined (based on $300,000 per fatality and $50 per lost work day). The range for sensitivity analysis was taken to be 5-25 cents per ton.

Surface mining for Powder River coal is expected to have productivity about four times that for the U.S. average of coal surface mining. Assuming recent figures for accident rates per million man hours gives an estimate of about one cent per ton of coal mined (sensitivity range 0.5 cents per ton to eight cents per ton) for occupational health and safety risks.

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