PRELIMINARY EVALUATION OF ALTERNATIVE PREVENTION OF SIGNIFICANT DETERIORATION POLICIES: A CASE STUDY OF OIL SHALE DEVELOPMENT IN COLORADO AND UTAH

FINAL REPORT

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May 1982

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USES AND LIMITATIONS OF THE ANALYSIS

This report was prepared under contract for the U.S. Environmental Protection Agency by Putnam, Hayes and Bartlett, Inc. The study represents a joint effort between EPA's Region VIII office in Denver, Colorado and the Office of Policy and Resource Management in Washington, D.C. and focuses on a critical environmental and energy issue, having both national and regional significance. Though prepared under the direction of EPA, the report's opinions and findings contained within are those of the authors and do not necessarily represent Agency policy.

The purpose of this study is to examine alternative PSD increment allocation and management approaches that are potentially available to the states of Colorado and Utah. Several national parks, wilderness areas, and national monuments that warrant special protection under the Clean Air Act are located in these states. Considerable energy development scheduled to take place in the area may consume the short-term SO_2 increment in several mandatory and potential Class I areas, indicating that PSD requirements may constrain potential energy development in the area. Since the state of Colorado is in the process of developing its own PSD program, this study is intended to assist the state in evaluating PSD management approaches that can be adopted at the outset of the state's program to mitigate any constraints on future energy development.

The analysis focuses on options that represent variations to the standard first-come, first-served approach that has been used heretofore by EPA and some states. The study does not recommend any one solution but instead offers several options, pointing out their relative strengths and weaknesses. The best option for either Colorado or Utah will be determined by the states based upon their individual needs and circumstances, political constituencies, growth patterns, and air quality management capabilities.

Due to the many uncertainties and limitations surrounding the data and air quality modeling associated with the analysis, the results for individual sources in Class I areas should be viewed with caution. The various estimates and modeling procedures that are crucial to the analysis are very crude at this stage of development. Current estimates of production capacities, emission rates, effectiveness of control technology, and the rate and pattern of development are only speculative at this time, even on the part of industry, and may change considerably as the oil shale industry develops. The air quality impacts are only rough approximations because of the inability of existing models to accurately estimate impacts in complex terrain areas over long distances, which are typical in the study area. Before credible estimates can be made that serve as the basis for actual permitting decisions, more advanced modeling procedures and more extensive meteorological data bases will have to be developed.

As a result of these limitations, the results of this analysis serve to illustrate the relative impacts of alternative allocation methods and do not represent precise results for the area. Even though the analysis offers informative comparisons among options, no conclusions should be drawn as to which facilities might obtain permits or the ultimate air quality impact of the potential development. The analysis should be used only for its intended purpose of judging the relative effectiveness and efficacy of the various management approaches.

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ACKNOWLEDGMENTS

In carrying out this effort, Putnam, Hayes & Bartlett, Inc. (PHB) received guidance and assistance from many Environmental Protection Agency (EPA) staff and other officials. Overall supervision of the effort was provided by EPA's project officers: Don Ryan (Energy Policy Division) and Ken Lloyd (Region VIII Analytic Center). In addition to these project officers, a number of individuals made contributions of time, data and ideas to the effort. These people include:

John Dale	EPA Region VIII
Richard Fisher	EPA Region VIII
Douglas Latimer	Systems Applications, Inc.
George Lauderdale	Colorado Department of Health

This report is a case study addressing EPA's policy for granting permits to new sources of air pollution locating near national parks and wilderness areas. The granting of permits is governed by the Prevention of Significant Deterioration (PSD) regulations. PSD regulations establish maximum allowable levels of ambient air quality deterioration for total suspended particulate (TSP) and sulfur dioxide (SO_2). These allowable levels of ambient degradation are called "increments." Under this air quality management approach, national parks and wilderness areas are allowed only small increases in pollution over baseline air quality levels. Because a number of this country's parks are located in areas having rich energy resources, many believe that the PSD regulations could constrain energy development in some areas.

This study addresses methods that can be used by states and in some cases the federal government to allocate the increment among sources in a manner that will maintain industrial development. Its purpose is to present and assess alternative increment allocation options. The focus is on options that represent variations to the first-come, first-served allocation approach which is commonly used by EPA and state agencies. This study also evaluates alternatives which would require changes in the Clean Air Act. This assessment can be used by individual states in determining the options that are preferred given their individual needs and circumstances.

To obtain quantitative results on the relative implications of the various options, a case study was developed to assess the options within the context of an actual area. The oil shale region of western Colorado and eastern Utah was targeted for this case study. The region includes eight mandatory and three potential Class I areas. This region has abundant shale oil reserves and will likely be the site of significant development. If all oil shale facilities proposed to date are built, production of nearly 1.2 million barrels per day of oil could be achieved by the end of the century.

Air quality modeling was conducted to evaluate the ambient air quality impact of the major emission sources in the study area. This modeling showed that the 24-hour sulfur dioxide (SO_2) increment for Class I areas would be the most constraining PSD standard for the region. However, in some areas TSP Class II increments may be exceeded and along with the SO_2 Class I increments could constrain oil shale development. The options that are evaluated in this report are judged in relation to the SO_2 Class I standard. A study of TSP Class II increments may be warranted if Class II protection remains in the Clean Air Act.

The case study evaluates allocation options that are available under the current program. It also considers some options that are not currently allowed but could result from amendments to the Clean Air Act. Any changes in the PSD program are speculative at this time, but the case study provides useful data on the implications of possible changes and their relation to the current approach. Throughout the report it has been assumed that the states of Utah and Colorado would collaborate and enact complementary PSD management strategies. This assumption is important because emission sources in one state can have an air quality impact on Class I areas in a neighboring state.

The remainder of this chapter describes each option that has been analyzed, data limitations, and the findings and conclusions for the case study.

OPTIONS ALLOWED UNDER CURRENT LAW

- Require Most Stringent Technology -- The permitting authority could require that sources apply very stringent control when demand for the increment was great. This option would allow more sources to site before the increment is consumed.

- Air Quality Offsets -- Offsets can be obtained either from existing sources or sources previously granted PSD permits which would enable the applicant to site without causing an increment to be exceeded.

- Retrofit Existing Sources -- Once the increment is consumed, the permitting authority could require existing sources to retrofit additional controls to provide a PSD "growth margin" for new sources.

- Retrofit PSD Permitted Sources -- This option is similar to the previous retrofit approach except that it would include the retrofit of sources that have previously obtained PSD permits.

- Variance -- A variance to the increments could be obtained according to the procedures prescribed by Section 165(d) of the Clean Air Act.

- Site Elsewhere -- Once the increment is consumed sources may choose to alter their site location to avoid violating the increment.

- Reserve the Increment -- The permitting authority could reduce the chances of an increment violation occurring by allowing PSD sources to use only a portion of the remaining increment, thus reserving some of the increment for future growth.

- Rely on Local Preferences -- State and local authorities could grant permits to facilities that would provide the greatest benefits to the region. Criteria for granting permits could include employment, tax revenue, and air quality impact.

OPTIONS THAT REQUIRE CHANGES IN THE CLEAN AIR ACT

- Annual Air Quality Increments Only -- This option abandons the short-term Class I increments while retaining the annual increment.

- Abandoning Short-Term Increment Tracking -- Under this approach, annual increments would be retained. However, each PSD applicant would be required to evaluate their emissions against the short-term increments instead of evaluating the cumulative emissions of all PSD sources against the increment.

- BACT Control with No Class I Increment -- Sources would receive permits after compliance with BACT requirements. The air quality impact of the source in Class I areas would not be considered in permit decisions.

- Emission Density Zoning (EDZ) -- An EDZ approach is a land-use-based air quality strategy which requires that emissions of a pollutant be limited to prescribed levels for a selected unit area.

- Economic Approaches -- A marketable permits or emission fee system could be instituted. Marketable permits and emission fees have advantages in that they can allocate the burden of control in an efficient manner.

There are several significant limitations to this study. In particular, because there are no full-scale oil shale facilities that are operational, the database of information on oil shale processes is extremely limited. Information in the following areas was difficult to quantify:

- SO_2 emission rates are uncertain since they are based on engineering studies of pilot plants and not actual emissions from commercial scale facilities.

- Air quality impacts are rough approximations because of the inability of existing models to accurately estimate impacts in complex terrain areas, such as the study area.

- Production processes that will eventually be employed for the facilities are uncertain since companies continue to evaluate various technologies and vary their processes accordingly.

- The order in which plants will apply for permits, whether the plants will even be built, and the ultimate size of the plants are subject to speculation. The timing and size of development by individual companies continue to change.

- Secondary emissions (e.g., road dust) were not included in the analysis.

- Uncertainties in the actual sulfur removal technology that will be employed and their design uncertainties make estimation of pollution control costs difficult and approximate.

As a result of these limitations, this study should not be construed to indicate which sources would obtain permits, rather, the focus is to indicate which PSD management alternatives have the potential to facilitate oil shale development and maintain air quality in Class I areas.

CONCLUSIONS

Exhibit 1-1 illustrates the maximum potential shale oil production levels allowed by each PSD alternative. Based on an analysis of each option the following conclusion can be made.

OPTIONS ALLOWED BY CURRENT LAW

- Preliminary air quality modeling indicates that all of the proposed oil shale facilities in the Colorado/ Utah study area could not receive PSD permits without violating the Class I increments

Exhibit 1-1

POTENTIAL OIL SHALE PRODUCTION
UNDER PSD ALTERNATIVE OPTIONS

Alternative*	Potential Production Including Mandatory Class I Areas (Thousands bbl/d)	Potential Production Including Mandatory and Potential Class I Areas (Thousands bbl/d)
Current FCFS Policy	465	315
Most Stringent Technology	515	365
Offsets	635	485
Retrofit Existing	635	485
Retrofit Permitted Sources	515	365
Variance	1190-1240+	1190-1240+
Variance/Offset	990	535
Annual Increment	1240+	1240+
Annual—Elimination of Short-Term Tracking	1240+	1240+
BACT	1240+	1240+

* Chapter 3 includes a detailed summary of each PSD management alternative.

at one or more Class I areas. Under the current first-come, first-served (FCFS) policy, only 465,000 bbl/d of oil shale development (seven sources) could obtain PSD permits when the mandatory Class I areas are considered. If the Dinosaur National Monument, presently a Class II area, is ultimately included as a Class I area, only 315,000 bbl/d of development (five sources) could obtain permits.

- The Flat Tops Wilderness area could constrain oil shale development in the Parachute Creek and Piceance basins. The Mt. Zirkel Wilderness area could constrain development in the Uinta basin. Two power plants (one in Colorado and one in Utah) may combine to consume the Class I increment at Mt. Zirkel. Thus, any further development of Unita basin may require sources to obtain variances or offsets.

- Allowing sources to obtain air quality offsets but not variances from Class I increments would increase the maximum allowed development compared with the current FCFS policy. Oil shale development would therefore be 635,000 bbl/d or 485,000 bbl/d if Dinosaur is included as a Class I area.

- If the state required existing emission sources to retrofit SO_2 controls, the maximum oil shale production would be identical to the offset approach. The primary differences between the two options are: 1) distribution of costs between new and existing sources and 2) the timing of incremental pollution control costs. From an equity perspective, an offset trading program would be preferable to the retrofit option because offsets would require the sources that need permits to pay for the offset. A retrofit approach would require the existing sources to pay for the additional equipment. Furthermore, the regulatory authorities may not require retrofit of the most cost-effective sources. In addition, the implementation of a retrofit strategy may require extensive collaboration between Utah and Colorado because sources in one state impact Class I areas in the adjoining state.

- A most stringent technology policy would limit oil shale development and place significant additional costs on the sources that could obtain permits. For example, if more stringent technology were required for all sources, only one additional source (beyond the current first-come, first-served strategy) would receive a permit. The costs of installing most stringent technology would approximately double the costs of installing BACT control. Total annualized costs for pollution control for the oil shale sources would increase from $92.6 to $200.9 million.

- A final option allowed under current law, the granting of Class I variances, would allow the majority of proposed oil shale sources to obtain PSD permits. This development would be accompanied by higher SO_2 concentrations at the Class I areas. It is difficult to quantify how much growth could take place under a variance approach since Section 165(d) calls on the federal land manager of the Class I area, and in certain cases, the governor of the state or the president, to make subjective decisions regarding the proposed plants effects on air quality values in these areas. However, under the basic requirements of Section 165(d), a minimum of nearly 1,200,000 bbl/d of oil shale development could take place. This amount of growth would correspond to a 24-hour SO_2 concentration of approximately 9.6 ug/m³ at Flat Tops, 10.9 ug/m³ at the Dinosaur Park National Monument and 5.7 ug/m³ at the Mt. Zirkel Wilderness area.

- An alternative which would allow substantial development would be to grant a variance from the Class I increments at Flat Tops and use offsets to maintain the air quality at Mt. Zirkel. Under this alternative, one million bbl/d of development (sixteen of the eighteen total sources) could obtain PSD permits. If the Dinosaur Monument is included as a Class I area, this alternative would allow development of only 535,000 bbl/d. Additional variances for sources violating the increment at Dinosaur would be required or further development would be constrained.

OPTIONS WHICH REQUIRE CHANGES IN THE CLEAN AIR ACT

- Elimination of short-term increments while retaining the annual increment would also allow more energy development to take place in the region. If all the proposed sources were to obtain PSD permits, the highest annual SO_2 increment reading would be 0.62 ug/m³ at Flat Tops. The coinciding 24-hour SO_2 value at Flat Tops would be 9.6 ug/m³.

- The elimination of short-term increment tracking would have no effect because no individual PSD source has a 24-hour SO_2 impact of over 5.0 ug/m³ in Class I areas. Thus, this option would have the same impact as the annual increment.

- A policy which would eliminate PSD increments and require sources to comply with BACT would degrade air quality at the parks compared with other alternatives but would allow development to the secondary NAAQS. If this approach were implemented, the 24-hour increment would be 9.6 ug/m³ and 10.9 ug/m³ at the Flat Tops and Dinosaur areas, respectively, if all the proposed sources were constructed. The control costs for the sources would also be less because no offsets or additional control would need to be purchased.

SENSITIVITY ANALYSIS

Sensitivity analyses were conducted on the results of the first-come, first-serve analysis. One sensitivity analysis included increasing emissions from several facilities that may have on-site refining. Another analysis involved changing the order in which plants applied for permits so air quality impact would be minimized. In each case the oil shale development estimates were not significantly altered.

A final sensitivity analysis included the relaxing of the increment ceiling for sources in the Uinta basin. The air quality modeling conducted for this study indicates that two power plants may consume the increment at Mt. Zirkel, and, therefore, oil shale facilities in the Uinta basin may be unable to obtain PSD permits. The air quality contribution for all Uinta oil shale sources at Mt. Zirkel is so small (about 0.7 ug/m^3) that any refinement in the modeling may change the results considerably. If these sources could obtain PSD permits, they would represent an additional 280,000 bbl/d of growth. Under the first-come, first-served approach maximum growth would increase from 465,000 to 745,000 bbl/d when the mandatory Class I areas are considered.

FORMAT OF REPORT

The next two chapters describe the current PSD policy and alternatives for allocating the PSD increment. Chapter 2 describes the current program and associated problems. Chapter 3 provides a description of each option to be analyzed and contains a general discussion of how each option would work. Chapters 4 through 6 are concerned with the analysis and results of the case study. In Chapter 4 the study area is described. Chapters 5 and 6 present the results of the analysis and an evaluation of the potential of each alternative increment allocation option. Chapter 7 compares the SO_2 control costs, air quality impact, and growth potential between these alternatives and the current policy. Five appendices at the conclusion of this report include a description of each emission source, a description of the SO_2 control cost data that was used, and a summary of the air quality results.

THE CURRENT PSD PROGRAM

The 1977 Congress specified the basic framework of the current PSD program in Sections 160 through 169 of the Clean Air Act. Since then, EPA has promulgated regulations at 40 CFR 51.24 and 52.21 which implement the basic framework.

The fundamental principle for the current program is that air quality in any clean air area may not significantly deteriorate. With respect to emissions of total suspended particulate matter (TSP) and sulfur dioxide (SO_2), Congress defined how much deterioration would be significant by means of an area classification scheme. Congress classified certain national parks and other special areas as Class I and the rest of the country as Class II.* It then authorized any state or Indian governing body to reclassify its Class II lands to Class I or, with some exceptions Class III. Finally, Congress specified "maximum allowable increases" (increments) in concentrations of TSP and SO_2 over a baseline level for each of the three classes. The increments for Class I areas are small; for Class II areas, of moderate size; and for Class III areas, larger still. In addition, the

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* Class I areas include international parks, national wilderness areas which exceed 5,000 acres in size, and all national parks which exceed 6,000 acres.

increments are based on different averaging periods, specifically, 24 hours and one year for TSP and 3 hours, 24 hours and one year for SO_2. Exhibit 2-1 lists the increment values for TSP and SO_2 for each averaging period.

In addition to specifying increments, Congress defined the baseline level. The baseline level is the measured concentration of the pollutant in question in a particular area on the date of the first application for a PSD permit. Congress, however, expressly provided that the baseline level not include the emissions of TSP and SO_2 from any major stationary source on which construction commenced after January 6, 1975.

With respect to criteria pollutants other than TSP and SO_2, Congress left to EPA the task of defining how much deterioration would be significant. Since EPA has not yet proposed implementing regulations, only deterioration beyond National Ambient Air Quality Standards (NAAQS) for one of those other pollutants would be significant.

The primary mechanism for preventing significant deterioration is the permit requirement. Before beginning construction on a new "major stationary source" or "major modification" in a clean air area, a company must obtain a PSD permit.* The following requirements must be fulfilled to obtain a permit:

1. Propose an emission limitation or, if that is not feasible, a design or work practice standard;

2. Show that the proposed limitation or standard is as stringent as "best available control technology" (BACT) and that the project would meet it. BACT means the maximum degree of emissions reduction "which the permitting authority, on a case-by-case basis, taking into

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* EPA has defined by regulation the terms "major stationary source" and "major modification."

Exhibit 2-1

PREVENTION OF SIGNIFICANT DETERIORATION
AIR QUALITY INCREMENTS

Pollutants	Maximum Allowable Increase* (ug/m^3) Class I	Class II	Class III
Particulate Matter			
Annual Geometric Mean	5	19	37
24-Hour Maximum	10	37	75
Sulfur Dioxide			
Annual Arithmetic Mean	2	20 (15)	40
24-Hour Maximum	5	91	182
3-Hour Maximum	25	512	700

SOURCE: Clean Air Act Amendments of 1977, Title I, Part C, Section 163, August 7, 1977.

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* Maximum allowable increases over baseline concentrations not to be exceeded more than once per year except for annual where allowable increases over baseline may not be exceeded.

account energy, environmental, and economic costs, determines is achievable" for the project. BACT must be at least as stringent as any applicable standard under Section 111 (NSPS) or 112 (NESHAPS);

3. Show that the project, given the proposed limitation or standard, would neither cause nor contribute to a violation of any PSD increment or NAAQS;

4. Provide an analysis of air quality in the area where the project would have a significant impact. This analysis must generally include monitoring data over a period of one year for any criteria pollutant.

5. Provide an analysis of the effect that the project would have on soils, vegetation and visibility in the area where the project would have a significant impact;

6. Provide an analysis of the effect that growth associated with the project would have on air quality; and

7. Provide such post-construction monitoring data as the permitting authority determines is necessary.

Even if an applicant shows that its proposed project would neither cause nor contribute to a violation of an increment over a federal Class I area, the permitting authority could deny the application if the federal land manager (FLM) of the area shows to the satisfaction of the permitting authority that the project would impact the air quality-related values of the area adversely. Conversely, even if a project would violate an increment over a federal Class I area, the permitting authority could still issue a permit if the FLM certifies that the project would not affect the air quality-related values of the area adversely or, in certain cases, if the applicant otherwise obtains a variance.

There are some perceived problems with the approach to preventing significant deterioration defined above. The permitting procedure is often tedious and time consuming. If permits are allocated on a first-come, first-served (FCFS) basis, as is normally the case, the distribution of permits and therefore industrial development in the region could be undesirable. For example, national interests, such as energy development, may not be satisfied by a first-come, first-served allocation procedure. Furthermore, once the increment is consumed, without some form of emission trading or a variance, no further development could occur in the region.

Within the current program there are options that can overcome these problems. The next chapter describes the options available to state authorities under the current program and several options which would require changes in current law.

As mentioned in the previous chapter, the current approach to air pollution control could potentially limit energy development near Class I areas. This chapter describes several options for allocating the PSD increment that may serve to alleviate this limitation. These options are separated into two categories: those that could be employed under the current Clean Air Act and those that would require changes to the Clean Air Act. This final category includes several economic and zoning approaches that would require significant restructuring of the current law. In all cases, it is assumed that the states of Colorado and Utah would implement similar PSD management strategies. This assumption is necessary because emission sources in one state can affect Class I areas in adjoining states.

OPTIONS ALLOWED UNDER CURRENT LAW

Most Stringent Technology

Under the most stringent technology option, state officials would require new sources to install more stringent technology after there appeared to be pressure on the increment ceiling. Most stringent technology would correspond to additional pollution control requirements beyond those normally required to meet BACT. Under this approach air quality would deteriorate more slowly than with the FCFS approach. New sources would bear a greater financial burden than under the current approach or the offset option. One disadvantage of this approach is that the most cost-effective means of limiting emissions would probably not be achieved. New sources would have to install strict technology as opposed to possibly obtaining less expensive offsets from existing sources.

Offset Approach

Under current policy, a new source seeking to locate in an area where the PSD increment has been consumed could be denied a permit if its emissions resulted in an air quality impact which exceeded the allowable limits. Air quality offsets are one way to avoid this problem by allowing new sources to offset the impact of their emissions by persuading existing sources to reduce emissions. When a prospective source purchases an offset from an existing source, the existing source agrees to control its emissions so that the new source can produce some emissions. Thus, total air quality would not deteriorate and economic growth in the region could continue.

In order to receive a PSD permit using the offset option, the proposed facility must first apply BACT. The applicant must then be able to purchase offsets from existing sources so that air quality increments would not be exceeded.

Offsets can occur within one company (internal) or among different companies (external). The majority of transactions to date have been internal. In the case of external offsets new sources would bear the financial burden of control because they would have to purchase offsets from existing sources to receive a permit. To the extent that offsets are purchased, the offset selling sources would benefit from having located in an area before the increment ceiling is reached.

One advantage of this approach is that a market for the purchase and sale of offsets would develop. The market would assist sources in purchasing the least-cost (and therefore cost-effective) pollution controls. These incentives for economic efficiency are not found in all the other options. The only disadvantage would be if there were not enough sources to establish a significant market.

Retrofitting Existing Sources

Another option would be for state officials to require existing emission sources to retrofit additional control equipment once the increment has been consumed. Officials could mandate that all sources uniformly rollback their emissions or could mandate retrofit of the lowest cost sources. The uniform rollback approach was not evaluated because it would be more costly than the least cost retrofit option.

Under the least cost retrofit approach, the costs of installing additional pollution controls would be borne by the retrofitted sources. This is in contrast to the offset approach where the sources seeking to obtain PSD permits would be required to pay additional pollution control costs when purchasing air quality offsets. If the existing facilities can install additional control and if the available offset potential from these sources were quite large, then air quality in the region could be maintained without curtailing development. However, the retrofit of existing sources may not provide an ample margin for growth, and other options would have to be considered to accommodate proposed oil shale facilities.

Retrofitting Oil Shale Facilities

This approach is similar to the previous retrofit option except that the retrofit would be mandated for oil shale sources that had already received a PSD permit. This option would be implemented after the increment ceiling had been reached. The advantage of this approach compared with the most stringent technology option is that current facilities would not have to install additional control until the increment ceiling is reached, and therefore additional costs would be postponed. A second advantage is that this approach would allow officials flexibility in controlling oil shale plant emissions. Because of the tremendous uncertainty involved in the current emission estimates, a policy which allows officials to require additional control may be advisable. This retrofit option will be evaluated separately from the retrofit of existing sources strategy.

Variance Approach

Another option for new sources that wish to locate in an area in which the increment has already been consumed is provided by Section 165(d) of the Clean Air Act. It contains two mechanisms by which sources may be granted waivers to Class I increments.

The first provision, Section 165(d)(2)(C), states that a source that violates the Class I increments may obtain a permit if it demonstrates to the satisfaction of the federal land manager (FLM) that it will have no adverse impact on the air-quality-related values of the Class I area.* If the FLM so certifies, maximum allowable increments are:

	Concentration Over Baseline Levels (ug/m^3)
Particulate Matter	
Annual Geometric Mean	19
24-Hour Maximum	37
Sulfur Dioxide	
Annual Arithmetic Mean	20
24-Hour Maximum	91
3-Hour Maximum	325

If a source is not granted a waiver under Section 165 (d)(2)(C), a second waiver provision is available to the source under Section 165(d)(2)(D). However, this provision is available only for waivers of short-term SO_2 increments. The source must first demonstrate to the state that a variance would not adversely affect an air-quality-related value. If the governor is satisfied

* Conversely, if the FLM finds that a source would have an adverse effect on the "air-quality-related values" of a Class I area, and demonstrates this "to the satisfaction" of the permitting state, the permit must be denied even if there would be no increment violation.

with this demonstration and if the FLM concurs the governor may grant a variance.*

If a variance is granted by the governor or the president, the source is allowed to violate the existing short-term increments 18 days per year and must comply with the following increments:

	Concentration Over Baseline SO_2 Levels (ug/m^3)
Low Terrain Areas	
24 Hour	36
3 Hour	130
High Terrain Areas	
24 Hour	62
3 Hour	221

Both the variance options allow economic growth in the area after the PSD increment is consumed. They are also attractive in that they allow a case-by-case judgment as to whether the air quality deterioration is significant given other factors. The financial burden on new sources will be smaller than under the offset option since the purchase of offsets would not be needed.

Alternative Siting

An option that would be available to plants that are denied a PSD permit would be to locate at another site where their air quality impact would be minimized. While this alternative may be successful near some Class I areas, this option is not a reasonable approach for this study due to the site-specific characteristics of the oil

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* However, if the FLM does not concur, then both his recommendation and that of the governor's are transmitted to the president, who may approve the governor's recommendation if he finds that a variance is in the national interest.

shale processes. From a local perspective, this option would not be as attractive as the others that allow development.

Reserving the Increment

If there appears to be pressure on the PSD increment, a portion of the increment could be reserved for future emission sources. This option could require new sources early in the queue to incur additional control costs relative to those costs which would be incurred by the current FCFS policy. The additional cost occurs because sources are forced to apply more stringent control sooner rather than later. For example, if only a portion of the increment were available each year but a number of sources apply for permits in that year, some of the applicants would need to reduce their air quality impact by applying additional control or possibly purchasing offsets. These additional costs of obtaining a permit would occur even though a portion of the increment was still available for later years.

This option can be evaluated with the use of a simple example. In this example, it is assumed that after 3.0 ug/m^3 of increment had been consumed, state officials would allow only 0.25 ug/m^3 of increment to be consumed annually. If there were demand for 0.5 ug/m^3 per year, this policy would require sources to purchase offsets, reduce their emissions, or pursue another strategy to make up for the additional 0.25 ug/m^3. If, for simplicity, it is assumed that each 0.25 ug/m^3 of additional reduction would cost a constant $5 million annually, then the sources would have to spend $5 million each year until the 5.0 ug/m^3 ceiling was reached. Exhibit 3-1 illustrates the costs to future sources during each year for a 10-year period assuming that the 3.0 ug/m^3 level had been reached at the start of the first year. After 8 years the increment ceiling of 5.0 ug/m^3 is reached, and 0.5 ug/m^3 would be needed by new sources each year. The total cost of this approach over this time period would be $60 million in 1980 dollars.

Exhibit 3-2 illustrates the costs of the current first-come, first-served policy using the offset approach when the increment is consumed. The same assumptions as those in the previous example apply. No increment

Exhibit 3-1

COST OF RESERVING THE PSD INCREMENT
OVER A 10-YEAR PERIOD

Year	Air Quality Increment Available* (ug/m³)	Air Quality Increment Demanded (ug/m³)	Alternative Control Strategy (mm$)
1	0.25	0.5	5.0
2	0.25	0.5	5.0
3	0.25	0.5	5.0
4	0.25	0.5	5.0
5	0.25	0.5	5.0
6	0.25	0.5	5.0
7	0.25	0.5	5.0
8	0.25	0.5	5.0
9	0.00	0.5	10.0
10	0.00	0.5	10.0
Total	2.00	5.0	60.0

* It is assumed that the 3.0 ug/m³ level has been reached and therefore only 0.25 ug/m³ can be used annually.

Exhibit 3-2

COSTS OF FCFS/OFFSET APPROACH
OVER A 10-YEAR PERIOD

Year	Air Quality Increment Available (ug/m³)	Air Quality Increment Demanded (ug/m³)	Control Strategy (mm$)
1	2.0	0.5	0.0
2	1.5	0.5	0.0
3	1.0	0.5	0.0
4	0.5	0.5	0.0
5	0.0	0.5	10.0
6	0.0	0.5	10.0
7	0.0	0.5	10.0
8	0.0	0.5	10.0
9	0.0	0.5	10.0
10	0.0	0.5	10.0
Total	5.0	5.0	60.0

reductions are required during the first four years because there is enough increment available to meet the demand. After the fourth year the increment is totally consumed and sources have to reduce their impact or purchase offsets in order to obtain permits. The total cost of offsets over the ten-year period would also be $60 million. This total cost is identical to the cost of the offsets in the reservation of the increment example, except that costs are not incurred until the fifth year.

As all other components of the two approaches (the air quality, number of sources seeking permits and the distribution of costs) are identical at the end of the 10-year period, a net present value analysis is the best indicator of the preferable alternative. Regardless of the discount rate assumed, the current FCFS policy with offsets would always have lower total costs than the increment reservation option. The only possible advantage of the reservation approach would be to change the distribution/equity advantages enjoyed by those sources first in the queue.

Local Preference

The local preference option involves local and/or state officials making decisions, based on a number of criteria, about which facilities should be able to receive PSD permits. These criteria can include the employment, economic and air quality impacts of the different plants that would like to site in the area. Once it is apparent that there would be pressure on the increment ceiling, local officials could require sources seeking PSD permits to be reviewed so that the needs and priorities of local residents could be taken into account in the permit process.

There are many reasons why the residents of an area would desire some influence in the development that takes place within their jurisdiction. A primary reason would be to prevent unwanted development that could exhaust the PSD increment and make it more difficult for desired industry to locate in the area. Another reason for a local preference option is that industrial development can have a significant impact on the character of the area. Oil shale facilities can employ large numbers of transient construction workers for many years who are then replaced by a smaller permanent workforce. Small communities have a particularly hard time absorbing short-term population growths, and their areas may prefer a larger permanent workforce. The importation of construction workers and a small permanent workforce does little to help employment problems that many communities face.

The local preference option could be implemented in an auction format. Companies could bid for a portion of the remaining increment by offering to provide certain amenities to the area. The local and/or state authorities could then choose which sources could locate in the area, based on criteria determined to be most important. This option could change the rate of development of an area and the amount of increment that is consumed. This option has certain obvious advantages for the local community and it may be a reasonable method for controlling consumption of the increment and the pattern of industrial growth. It should be noted that local officials have considerable authority to control growth through zoning ordinances and so forth. Use of PSD policy to control growth may not be the most direct planning method; however, it could be attractive if it is viewed as a revenue generating measure. Because the impact of this alternative cannot be quantitatively evaluated it will not be included in the following chapters.

OPTIONS THAT REQUIRE CHANGES TO THE CLEAN AIR ACT

Annual Increments Only

This approach would remove the short-term 24-hour increment ceiling and retain only an annual increment. The justification for the approach is twofold; 1) the annual increment would protect the long-term air quality at Class I areas without prematurely constraining new industrial development, and 2) the uncertainties associated with modeling short-term air quality impacts would be alleviated.

In itself, this option is not a complete solution because although the ceiling is not reached as early as it is with a 24-hour increment, development may still be constrained at some point in time.

Annual Increments -- Elimination of Short-Term Tracking

This option is similar to the annual increment option since cumulative impacts from all sources are measured against the annual increment. However, instead of abandoning the 24-hour increment entirely, each individual source may not have an air quality impact on Class I areas greater than the current 24-hour increment.

The effect of this option would usually be similar to the annual increment approach. It would be stricter (result in better air quality and higher control costs) when one source has an impact that exceeds the 24-hour increment on its second worse day because that source would be required to add further emission control before it could receive a permit. This option is particularly applicable to power plants which can have a greater than 5.0 ug/m^3 impact on an area even when they comply with NSPS control levels.

BACT Control with No Class I Increment

Under this option there would be no Class I PSD increments. Instead, new sources could receive permits by complying with BACT determinations. Costs of control would probably decrease under this option and the burden of control would be distributed more equally among all permitted sources. Economic development could continue until constrained by the secondary 24-hour SO_2 NAAQS.

Emission Density Zoning

The term emission density zoning (EDZ) has been used to define a number of different land-use-based air quality management strategies. For the purposes of this study EDZ is defined as an air quality management strategy which requires that emissions of a pollutant be limited to prescribed levels for a selected unit area. This limit could vary depending on the size and location of each land area. One technique would be to allow decreasing amounts of pollution per land area as land areas become situated closer to the park. Air quality modeling would be needed to set the specific pollution limits.

A primary advantage of an emission density approach is that once the policy is established, regulatory decisions would be based on plant emissions instead of the air quality impact from the plant. This system would facilitate offset trading and streamline the permit process since air quality models would not have to be run for individual sources. Sources and officials could evaluate the pounds of emissions that would be allowed instead of the more ambiguous air quality impact. Clearly, the disadvantage of this program is that it would be difficult to determine the appropriate level of emissions for each area. Since little experience has been gained with this system, substantial administrative costs could be incurred in implementing this approach.

Economic Approaches

Economic approaches use market mechanisms to achieve desired results rather than traditional command and control approaches. Economic theory views the market mechanism as an "invisible hand" that efficiently allocates resources to their most productive use. In a free market, when large numbers of private enterprises compete to buy factors of production, the scarce resources go to those who can pay the highest price. Thus in the simplest analysis, prices allocate resources to their socially optimal uses.

Some resources, such as air, however, are not owned and are therefore not priced in a free market. Without government intervention, companies could emit pollutants into the air at no cost. The cost of a polluted environment is paid by society through health problems and reduced aesthetic benefits, but this cost is external to the firm imposing the cost. Thus, economic theory views pollution as a "market externality." Economic approaches to pollution control attempt to internalize this externality. Marketable permits and emission fees are two such approaches. These options and the emission density zoning approach just described are not evaluated in this case study since a detailed implementation plan would be needed to assess their impact. The marketable permits approach is discussed at length because EPA and the state of Colorado have expressed considerable interest in this program.

Emission Fees

Emission fees, on the other hand, are set charges that sources must pay for every unit of emission they produce. Under this option, the price of pollution would remain constant (or could be adjusted for inflation) but air quality levels would vary with the magnitude of the fee as well as with changes in economic conditions and pollution control costs.

Air quality levels could exceed the increment ceiling if emission fees were set too low and companies found it cheaper to pay than to control emissions. Since new sources would be allowed to locate in the area as long as they paid the emission fees, economic development would not be severely constrained. One advantage to this approach is that companies would have an incentive to develop new, more efficient control technologies that would reduce their costs.

Marketable Permits*

A marketable permit would have a specific face value that would entitle the owner to emit a given level of pollution over a given period of time in a particular location. The permit might also include other restrictions, obligations or instructions. Permits would be issued in denominations that would allow firms to buy and sell various quantities of permits. Specific trading rules would be needed to account for different contributions various emission sources may have on air quality. These trading rules would assure that air quality would not deteriorate as a result of permit trading. Trading

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* For a more detailed discussion, see: Putnam, Hayes & Bartlett, Inc., Application of a Marketable Permit System to the Control of Air Pollution, October 1980.

could be facilitated through an "exchange" which could be operated by local or state pollution control authorities. Enforcement and compliance could be monitored simply by determining if actual emissions, averaged over an appropriate time, exceed the number of permits held by the source.

The design of a marketable permit system requires specification of the following:

- Number of permits (emissions) issued,
- Allocation of permits,
- Denomination of the permit,
- Duration of the permit,
- Periodic revisions in the permit system,
- Operation of a trading exchange, and
- Role of federal, state and local air pollution authorities.

Each of these components will be discussed with reference to the PSD program.

Number of Permits

The number of permits to be issued in an area depends on the number of emissions and the desired air quality goal. Permits could be issued to existing sources and sources which have already obtained PSD permits at no charge. The number of permits would equal the compliance emission level. If the PSD increment is not consumed, then a number of additional marketable permits would be available. For each new source the state would issue permits based on a formula that would consider BACT requirements. For each area the total number of permit sources would depend on the baseline air quality level, the PSD increments, and the ambient standards.

Allocation of Marketable Permits

The initial allocation of permits to existing sources would probably be implemented on the basis of a regulatory proceeding and could involve the revision of State Implementation Plans (SIP). The initial distribution of permits should provide for:

- Implementing the current pollution control standards for sources which have already obtained federal and state permits,
- Incentives for the trading of permits which would result in lower regional pollution control expenditures, and
- Implementing the program in as equitable a manner as possible.

Auctioning permits, selling permits at a fixed price, or distributing permits free of charge are several options for the initial distribution of permits. Selling or auctioning permits would transfer income from pollution sources to the government, requiring pollution sources to incur an additional expense over and above expenditures for installing and operating pollution control equipment. Distributing permits free of charge results in income transfers only among pollution sources.* Allocation of permits free of charge seems to be the most appropriate method for the initial distribution of permits to existing sources.

In a PSD area, such as the oil shale region, sources which have already obtained the necessary state and federal permits could be allocated marketable permits that reflect their compliance emission levels. The options for allocating permits to new sources are: first-come, first-served; a flat fee per permit; or an auction. The latter two options may promote more efficient use of a scarce PSD increment. An analysis of the effect of these three options would be needed to select the appropriate approach.

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* Sources with high costs of pollution control would purchase permits and compensate sources with lower costs of pollution control.

Once the new sources have obtained permits, they would trade with other sources in the area providing they follow the usual trading rules. When the PSD increment is consumed, new sources wishing to locate in the area would have to purchase permits from sources which already have permits.

Permit Denomination

The units of denomination selected for marketable permits should facilitate trades among sources and assure that greater emission loadings do not result from permit trading.

The characteristics of a particular area will dictate the appropriate permit denominations. A pounds-per-day unit would be applicable if the short-term standard is binding and a pounds-per-week unit is appropriate if a long-term standard is binding. In the oil shale area, a pounds-per-day unit would be appropriate since the 24-hour SO_2 standard is binding.

Duration of Permits

The duration of the permit will have a major impact on its market value. Investment in pollution control equipment normally involves long-term capital commitments. Decisions on such investments are best made in a climate of predictability concerning the number and value of marketable permits. Permits of short duration may hinder capital investment planning since firms will be uncertain as to whether more or fewer permits will be issued in the future and what the future value of the permits might be. Permanent permits appear to provide the greatest certainty and stability for capital investment planning.

Periodic Revisions

Revisions in the number of marketable permits may occasionally be needed to correct for imprecise air quality modeling, imprecise estimates of emissions for oil shale sources, or because of changes in PSD increments. A concerted attempt should be made to minimize revisions as much as possible as they cause uncertainty in the value of the permit, affect market liquidity, and will tend to discourage an active market.

However, when revisions are required, the face value of each permit could be discounted. For example, the state could indicate that all permits would be worth 90 percent of their face value after a certain date. Before issuing such an order the state would have to examine the technical feasibility of obtaining the required region-wide emission reduction. If the technical feasibility analysis indicated that the emission reductions were possible then the state could implement the discounting procedure. This procedure could be phased in over a period of several years to allow sources to obtain the needed emission reductions.

Operation of Trading Exchanges

A trading exchange would be required to provide a method for matching buyers and sellers of permits. A marketable permit system contains a number of unique characteristics that must be considered in designing a trading system. First, the market will contain only a few participants. Second, the value that sources place on permits will vary widely and probably relate somewhat to their pollution control costs. Finally, the market will not be very active. Once the initial trading has been accomplished (and sources begin to commit to pollution control equipment), the only participants in the market will be: (1) new firms entering the area, and (2) sources which either by design (improved pollution control efficiency) or by accident find a discrepancy between the number of permits they hold and their emission level.

The objective of the trading exchange is to provide a mechanism where buyers and sellers are matched in such a way that the least-cost control sources install equipment and the high-cost sources buy permits. A centrally organized exchange staffed by private entrepreneurs or regulatory authorities would facilitate this objective. The management of the trading exchange would require dissemination of information on the supply and demand for permits. Such information might include clearing prices and transaction quantities. It is expected that the exchange would not be as constantly active as a stock exchange.

The Role of State and Local Air Pollution Authorities

To operate a marketable permit system, the state and local air pollution authorities will have to assume some new responsibilities. The operation of this system will require these authorities to:

- Issue and initially allocate permits,
- Develop permit trading rules to account for emissions with different air quality impacts,
- Review permit trades and possibly manage the trading exchange, and
- Determine compliance status of air pollution sources.

With the possible exception of managing the trading exchange, the state and local authorities should have the skills in house required to carry out these tasks. The most resource-intensive task would be to issue and initially allocate the permits. This would involve translating current emission limitations into specific allocations of permits to sources. A number of technical issues must be determined, including the appropriate averaging time, actual emission levels, the method of allocation, and so forth. A regulatory proceeding would probably be needed for this task. The other tasks could probably be carried out with little additional effort.

To facilitate the development of markets in marketable permits, a guidance document might be helpful. This document would assist firms in determining the value of marketable permits to facilitate the evaluation of alternatives, and would assist state and local air pollution authorities in designing and operating a marketable permit system.

A case study of the PSD program in western Colorado and eastern Utah was undertaken to evaluate the PSD increment allocation options. This area was selected for the following characteristics:

- The oil shale resources in the area are abundant and the possibility of extracting oil from shale has already attracted the interest of major energy companies. Some critics of the PSD program contend that future energy development in this area may be constrained by the PSD requirements.

- EPA and the state are interested in determining the extent to which energy development may be constrained by current PSD policy, and the viability of alternative PSD management options.

- In contrast to a previous PHB study, there are a small number of existing emission sources in the oil shale region which could provide air quality offsets once the increment had been consumed.*

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* Putnam, Hayes & Bartlett, Inc., Preliminary Assessment of Alternative PSD Management Approaches: A Case Study Based on the Experiences in Western North Dakota, April 1982.

Thus, permit allocation options which seemed most viable in the previous study may be less attractive here. Other options are analyzed which may be more applicable to this region.

STUDY AREA DESCRIPTION

The area of eastern Utah and western Colorado is sparsely populated and is characterized by rugged terrain: steep cliffs and high plateaus. The terrain influences weather patterns making air quality modeling difficult. Oil shale resources in the region are estimated to be 179 billion tons in the Parachute Creek/Piceance Creek Basin of Colorado, and 48 billion tons in Utah's Uinta Basin. The U.S. Geological Survey estimates that about 80 billion tons are "of adequate thickness to be reasonably regarded as the potentially recoverable resource base." This is 90 percent of the identified oil shale resources in the U.S. and, according to the Office of Technology Assessment (OTA), "the largest concentration of potential shale oil in the world."*

Exhibit 4-1 contains a map of the study region. The proposed oil shale facilities will be located in the three basins shown on the map: Uinta, Piceance Creek, and Parachute Creek. The Uinta Basin also is the site of the Moonlake Utility Project. The Craig and Hayden power plants, which are located to the north of Flat Tops Wilderness area, will also have an impact on some of the Class I areas. The Moonlake and Craig (unit 3) utility plants have already received PSD permits. The Hayden plant does not require a PSD permit as it is an existing source; however, it may provide air quality offsets to new sources.

The eight mandatory and three potential Class I areas located on the map are:

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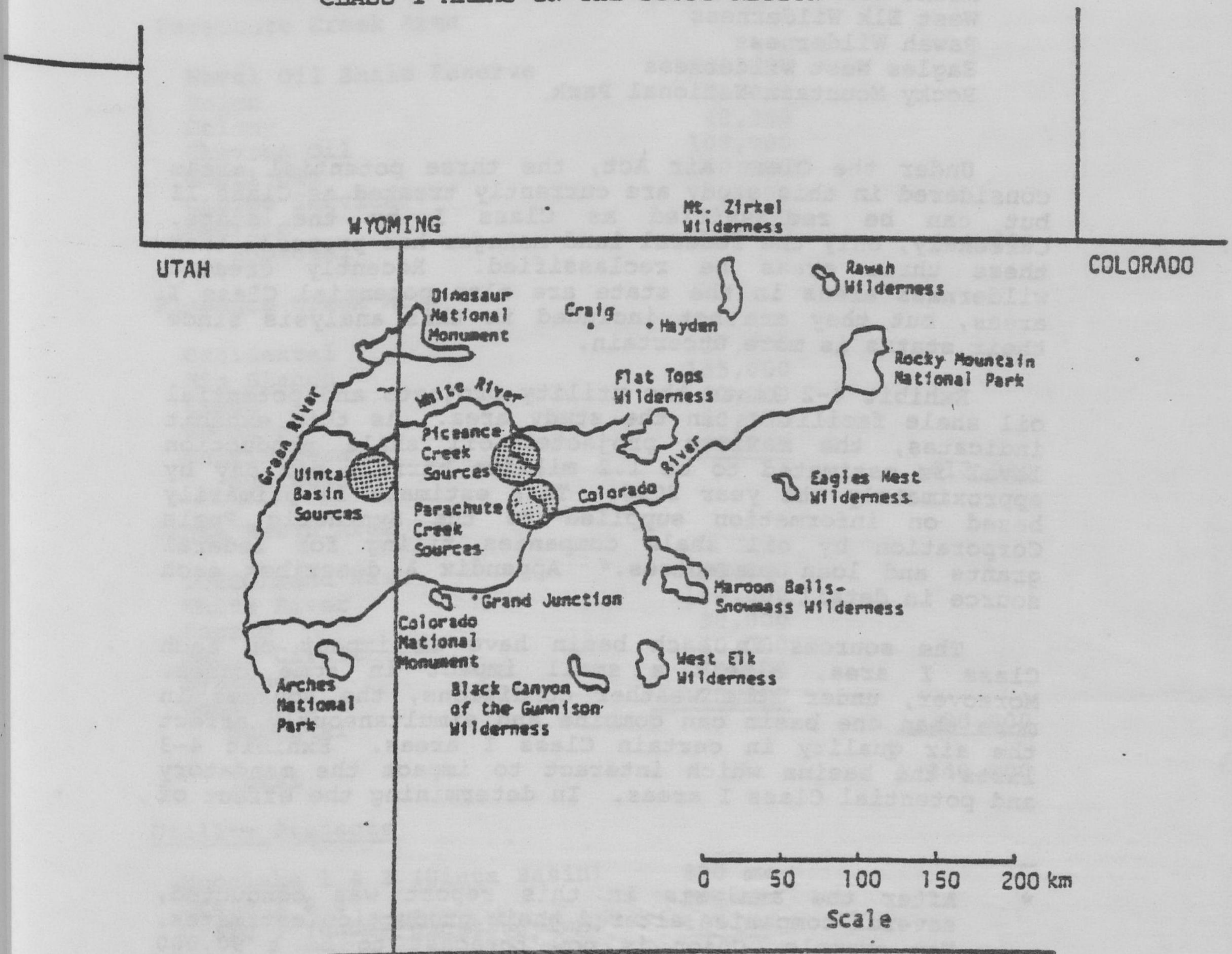
* Office of Technology Assessment, An Assessment of Oil Shale Technologies, Washington, D.C., June 1980.

Exhibit 4-1

LOCATIONS OF EMISSION SOURCE AREAS RELATIVE TO EXISTING MANDATORY AND POTENTIAL CLASS I AREAS IN THE STUDY REGION



SOURCE: Systems Applications, Inc., September 1981.

Mandatory Class I Areas	Potential Class I Areas
Flat Tops Wilderness	Dinosaur Natl. Monument
Arches National Park	Black Canyon of the Gunnison Wilderness
Maroon Bells Wilderness	Colorado Natl. Monument
Mount Zirkel Wilderness	
West Elk Wilderness	
Rawah Wilderness	
Eagles Nest Wilderness	
Rocky Mountain National Park	

Under the Clean Air Act, the three potential areas considered in this study are currently treated as Class II but can be reclassified as Class I by the state. Currently, only the federal land manager has proposed that these three areas be reclassified. Recently created wilderness areas in the state are also potential Class I areas, but they are not included in this analysis since their status is more uncertain.

Exhibit 4-2 lists the utility projects and potential oil shale facilities in the study area. As this exhibit indicates, the maximum projected oil shale production level is estimated to be 1.2 million barrels per day by approximately the year 2000. This estimate is primarily based on information supplied to the Synthetic Fuels Corporation by oil shale companies filing for federal grants and loan guarantees.* Appendix A describes each source in detail.

The sources in each basin have an impact on each Class I area, albeit a small impact in some cases. Moreover, under some weather conditions, the sources in more than one basin can combine and simultaneously affect the air quality in certain Class I areas. Exhibit 4-3 lists the basins which interact to impact the mandatory and potential Class I areas. In determining the effect of

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* After the analysis in this report was conducted, several companies altered their production estimates. For example, Union is now forecast to be a 90,000 bbl/d facility. At the time this study was undertaken, the production levels shown in Exhibit 4-2 were the most accurate available.

Exhibit 4-2

PRODUCTION CAPACITIES OF PSD SOURCES
IN THE COLORADO/UTAH STUDY AREA

Oil Shale Projects	Projected Production Level (bbl/d)	
Parachute Creek Area		
Naval Oil Shale Reserve	200,000	
Union	50,000	
Colony	48,300	
Chevron Oil	100,000	
Mobil Oil	50,000	
Cities Service	50,000	
Pacific	50,000	
Subtotal		548,300
Piceance Creek Area		
Occidental	117,000	
Rio Blanco	135,000	
Exxon	60,000	
Superior	50,000	
Multimineral	50,000	
Subtotal		412,000
Uinta Basin Area		
TOSCO/Sand Wash	50,000	
White River	100,000	
Paraho	30,000	
Magic Circle	30,000	
Syntana	50,000	
Geokinetics	20,000	
Subtotal		280,000
Total		1,240,300
Utility Projects		
Moonlake 1 & 2 (Uinta Basin)	820 mw	
Craig 1 & 2	894 mw	
Craig 3 (under construction)	447 mw	
Total		2,161 mw

SOURCE: Synthetic Fuels Corporation and PSD permits.

Exhibit 4-3

BASINS WHICH COMBINE TO
IMPACT MANDATORY AND POTENTIAL CLASS I AREAS*

Basin or Source	Mandatory and Potential Class I Areas
Uinta -- Piceance	Flat Tops
Uinta -- Parachute	Maroon Bells
Uinta -- Piceance	Rocky Mountain
Uinta -- Craig and Hayden**	Mt. Zirkel
Uinta -- Craig and Hayden**	Rawah
Uinta -- Parachute	Eagles Nest
Piceance -- Craig and Hayden**	Arches
Piceance -- Parachute	West Elk
Piceance -- Parachute	Dinosaur
Piceance -- Craig and Hayden**	Colorado National Monument

* This exhibit includes all of the basins or sources which combine to impact a Class I area. Although every basin or source may have an impact on individual Class I areas, in several cases, basins will have cumulative effects because pollution will overlap and impact an area.

** The Craig and Hayden power plants have air quality impacts on Class I areas even though they are not located in the three oil shale basins.

a new source on a Class I area the contribution of all PSD sources in the area needs to be taken into account.

EMISSION ESTIMATES*

Emission data for the oil shale plants are difficult to estimate because there are no commercial facilities in operation. Instead, emissions have to be estimated based on pilot plant emissions and laboratory studies. To estimate emissions (and control costs) for each plant, five general process categories were identified. For these five categories, either PSD permits or EPA technical studies on alternative oil shale technologies that provided emission estimates were available. Emission estimates will likely become more refined as full-scale plants are tested and developed. The categories are as follows:

- Union B process -- External indirectly heated retort; Source -- Union PSD permit application (7/31/79).
- TOSCO II process -- Internal indirectly heated retort; Source -- EPA technical studies on alternative oil shale technologies.
- Modified-in-Situ (MIS) process; Source -- Cathedral Bluffs-Occidental PSD permit application (4/13/81).
- Rio Blanco process -- Modified-in-Situ and Lurgi; Source -- EPA technical studies on alternative oil shale technologies.
- Paraho process -- Direct heated retort; Source -- EPA technical studies on alternative oil shale technologies.

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* Emission estimates for oil shale facilities are continually under review and are subject to significant change. The most up-to-date emission data may be obtained from the EPA Region VIII Air Branch.

Exhibit 4-4 lists each proposed oil shale facility with the process category to which it has been assigned for emission and cost purposes and the assumed SO_2 removal efficiencies. Sources were grouped by process technology because pollution control cost and emission data were not available on an individual plant basis. The reports and permit information used contained the most consistent data available. Appendix B contains a more detailed description of these categories. The category assignments have been reviewed by EPA personnel in Cincinnati responsible for oil shale emission studies.

These data are rough and preliminary; however, they are the best data currently available. Emission and control cost estimates can be refined once commercial-scale plants are in operation. As the results in this study depend on these estimates, any conclusions drawn from the case study should be re-examined when more accurate information is available.

PSD POLICY IN THE STUDY AREA

As mentioned earlier, the authority for implementing the PSD program still rests with the federal government. The Hayden power plant is the only source existing prior to implementation of the PSD program which is expected to have an impact on air quality in Class I areas. The Craig unit 3 and Moonlake power plants and two full-scale oil shale facilities have already received PSD permits. Two oil shale facilities have received permits for pilot operations. Several other oil shale facilities have applied for PSD permits. Exhibit 4-5 lists the oil shale sources and their PSD permit application status. Sources which have not filed PSD permit applications are listed according to the estimated date of initial production. The order in the queue is important to determine which sources will receive PSD permits before the increment is consumed. This queue was developed with data from a variety of sources and the dates of initial production are used as a proxy for PSD permit application dates. The study is mainly concerned with the total amount of production as opposed to particular sources that can obtain permits, thus, the queue is unimportant to the final results. The queue is used in the next chapter to determine the magnitude of the constraint to energy

Exhibit 4-4

OIL SHALE FACILITIES BY PROCESS TYPE*

Oil Shale Facility	Assumed Process Type	Approximate BACT SO_2 Removal Efficiency (%)
Union	Union	98.0
Colony/TOSCO	TOSCO II	96.9
TOSCO/Sand Wash	TOSCO II	96.9
Occidental	MIS	95.0
Geokinetics	MIS	95.0
Multimineral	Union	98.0
White River	Union	98.0
Superior	TOSCO II	96.9
Pacific	TOSCO II	96.9
Paraho	Paraho	96.4
Magic Circle	Union	98.0
Rio Blanco	Rio Blanco	99.8
Exxon	TOSCO II	96.9
Chevron Oil	Union	98.0
Mobil Oil	Union	98.0
Syntana	TOSCO II	96.9
Naval Oil Shale Reserve	Paraho	96.4
Cities Service	MIS	95.0

* Sources were grouped by process technology because pollution control cost and emission data were not available on an individual plant basis. The reports and permit information used contained the most consistent data available.

Exhibit 4-5

PRODUCTION QUEUE FOR OIL SHALE FACILITIES
(Estimated Start-up Dates)*

Company/Project	Permit Status	Estimated Initial Production
Union	Pilot Permit Granted 7/79 Pilot Upgrading Permit Granted 6/81	1983
Colony	Permit Granted 7/79	1985
TOSCO/Sand Wash	Permit Granted 12/81	1987
Occidental	Permit Withdrawn**	1988
Geokinetics	Pilot Permit Granted 11/80	1984
Multimineral	--	1984
White River	Permit Pending	1986
Superior	--	1986
Pacific	--	1986
Paraho	Permit Pending	1986
Magic Circle	--	1986
Rio Blanco	Pilot Permit Granted 12/81	1987
Exxon	--	1987
Chevron Oil	--	1988
Mobil Oil	--	1990
Syntana	--	?
Naval Oil Shale Reserve	--	?
Cities Service	--	?

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* Facilities are ranked according to estimated production dates except when PSD permits have already been granted or filed. The plants with pending permits are ranked in order of their application dates. The Moonlake and Craig unit 3 power plants received PSD permits before any of the oil shale facilities received pilot permits and thus are ranked first in the queue.

** Occidental is currently assessing whether to alter its proposed oil shale process technology.

development caused by the PSD program and not to identify sources which may have difficulty obtaining PSD permits. One might expect that significant changes in the order of the queue may occur.

AIR QUALITY MODELING

To develop the oil shale case study, PSD-permitted sources, sources with pending PSD applications, and proposed oil shale facilities must be modeled to determine the amount of air quality increment consumption. Existing sources need to be modeled to determine the available pool of offsets. Proposed oil shale facilities and sources with pending applications were also screened for possible visibility impacts. These impacts were not determined to be a major deterrent to growth in the study area.* It is expected that the 24-hour Class I SO_2 increment would be the binding constraint on future growth.

One of the main limitations of this case study is associated with air quality modeling. Predicting the air quality impact of sources in high-terrain areas is extremely difficult because of the lack of appropriate long-range, complex terrain models. Even though modeling is the cornerstone for any evaluation of PSD increments, this study is not intended to have air quality modeling as its focus. The Bureau of Land Management is currently conducting extensive modeling using high-terrain models in an effort that may improve modeling techniques used in future PSD permit decisions.

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* The air quality modeling for this study was conducted by Systems Applications, Inc. (SAI). See Prevention of Significant Deterioration Policy Implications for Projected Oil Shale Development, November 1981.

The air quality modeling for this study was reviewed by EPA Region VIII staff. Several sources in the area have been modeled previously in the course of PSD permitting decisions. These analyses did not include existing sources that could be potential sources of offsets, and they did not include all the proposed oil shale facilities. EPA contracted with Systems Applications, Inc (SAI) to conduct original air quality modeling to support this study. The result of this analysis may differ from previous and ongoing air quality analyses of the area.*

SAI used generic screening models that take into account the drainage and upslope flow conditions that were observed in the study region. There are a number of important caveats regarding the SAI results. These caveats include:

- The characteristics of future oil shale facilities are not certain. The design, capacity, and precise location of many of the facilities are not known; emission estimates and stack parameters (height, velocity, etc.) are very uncertain. This uncertainty is primarily due to the changing nature of the shale processing technology and because a number of companies have not fully committed to a certain technology.

- The models used for the study are <u>not</u> EPA-approved models and thus should not be used for making actual permit decisions. SAI's model generally predicts smaller concentrations than EPA's VALLEY model, which is commonly used in high-terrain situations.

- Worst-case meteorological conditions are based on limited observational data and SAI professional judgment regarding plume transport,

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* SAI and state authorities may use different SO_2 emission rates, meteorological parameters and air quality models in doing their analyses. Variations in these three factors may lead to different air quality estimates.

dispersion, and ground-level impacts in the complex terrain typical of this area. Gathering field data would have been an expensive and time consuming task.

PHB made several adjustments to the SAI air quality estimates. These adjustments were necessary because the emission estimates that SAI used were outdated in comparison to the more recent emission data that is included in PSD permit applications and internal EPA documents. Chapter 4 discusses the sources of data used by PHB to develop emission estimates. Exhibit 5-1 summarizes the SO_2 emissions used by SAI, which were based on previous studies, and the estimates that PHB used in the analysis. For each process, a different emission estimate was used.* The Paraho, MIS, and Rio Blanco processes have substantially higher emissions than originally used by SAI. These new emission estimates were used to adjust the SAI air quality estimates.** The remainder of the analysis is conducted using the scaled air quality impact figures.

THE BASE CASE

The base case scenario evaluates the current PSD program which issues PSD permits on a first-come, first-served basis until the Class I increment is consumed. This section describes the results of the air quality modeling for each source in the study area. A discussion of the alternatives available under the current law follows the base case description.

Existing Sources

SAI determined that only one existing SO_2 source has an impact on any of the mandatory or proposed Class I

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* SAI based their SO_2 emission estimates on a 1979 DOE/DRI study.

** Air quality estimates can be linearly scaled because of the type of modeling that SAI conducted. Therefore, if emission estimates are doubled, the air quality impact of the particular source may be doubled.

Exhibit 5-1

SAI AND ALTERNATIVE SO_2 EMISSION ESTIMATES*

Process (size-bbl/d)	SAI Emission Estimate (lbs/1000 bbl)	Alternative Emission Estimate (lbs/1000 bbl)
Union (10,000)	293	216
Paraho (55,000)	60	153
MIS (117,000)	115	381
TOSCO II (47,000)	158	136
Rio Blanco (63,000)	53	190

* These emission levels correspond to assumed BACT control levels. Alternative estimates are based on EPA technical reports and PSD permit information. Barrel per day estimates may differ from the production estimates listed in Exhibit 4-2. The figures in this exhibit are those that correspond to the facility size analyzed in EPA technical reports or PSD permits.

areas in the study area. This source is the Hayden electric generating station. The total 24-hour SO_2 concentration for this source ranges from 0.5 ug/m^3 at Arches National Park to 7.9 ug/m^3 at Mt. Zirkel. Exhibit 5-2 summarizes Hayden's impact on each Class I area.

Currently, the Hayden plant has no SO_2 control equipment. Appendix C includes a description of this plant, including the quantity of coal burned at the plant and the average sulfur content of the coal.

PSD Permitted and Proposed Sources

Exhibits 5-3, 5-4, and 5-5 illustrate the air quality impact of the facilities in Parachute Creek, Piceance Creek, and Uinta Basin, respectively. The exhibits show the cumulative impact of the potential sources in each basin on the mandatory and potential Class I areas. The impact of the three basins (Parachute, Piceance, and Uinta) on the Class I areas are discussed separately because, in general, the impact of the sources in one basin do not interact with the plumes of sources in separate basins. Therefore, each basins' impact on the Class I areas is independent of one another, and in some cases these basins have cumulative effects when their pollution overlaps at a Class I area. Exhibit 4-3 in the last chapter lists the areas which combine to impact a Class I area. These special cases will be discussed later in this section.

Individual sources and basins have varying impacts depending upon the Class I area considered. For example, the cumulative impact of the Parachute Creek facilities ranges from 1.2 ug/m^3 at Rawah to 9.2 ug/m^3 at Flat Tops. If all the proposed Parachute Creek facilities were built, increment violations would occur at Flat Tops (9.2 ug/m^3), Maroon Bells (6.0 ug/m^3) and the Colorado National Monument (7.7 ug/m^3).* The cumulative impact of the

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* PSD regulations specify that the Class I SO_2 increment ceiling is violated when the <u>second</u> highest 24-hour reading for the permitted sources exceeds 5.0 ug/m^3.

Exhibit 5-2

IMPACT OF HAYDEN GENERATING STATION ON CLASS I AREAS

Mandatory Class I	24-Hour SO_2 Impact of Hayden* (ug/m^3)
Flat Tops	5.7
Mt. Zirkel	7.9
Maroon Bells	1.3
West Elk	0.9
Arches	0.5
Rawah	1.9
Eagles Nest	2.1
Rocky Mountain	1.7
Potential Class I	
Dinosaur	1.9
Black Canyon	0.7
Colorado Monument	0.8

* The 24-hour SO_2 impacts represent the estimated impact on the second worst day at each Class I area.

Exhibit 5-3

AIR QUALITY IMPACT OF PARACHUTE CREEK FACILITIES
ON THE CLASS I AREAS

	Parachute Creek Facilities (ug/m^3)							
Mandatory Class I	Union	Colony	Pacific	Chevron	Mobil	NOSR	Cities Service	Total
Flat Tops	0.7	0.4	0.9	1.4	0.7	2.0	3.1	9.2
Mt. Zirkel	0.1	0.1	0.2	0.3	0.1	0.5	0.7	2.0
Maroon Bells	0.4	0.3	0.6	0.9	0.4	1.3	2.1	6.0
West Elk	0.4	0.2	0.5	0.7	0.4	1.0	1.7	4.9
Arches	0.2	0.1	0.3	0.4	0.2	0.5	1.0	2.7
Rawah	0.1	0.1	0.1	0.2	0.1	0.3	0.1	1.2
Eagles Nest	0.2	0.1	0.3	0.4	0.2	0.5	1.0	2.7
Rocky Mount.	0.1	0.1	0.2	0.2	0.1	0.3	0.7	1.7
Potential Class I								
Dinosaur	0.4	0.2	0.5	0.7	0.4	1.0	1.7	4.9
Black Canyon	0.4	0.2	0.5	0.7	0.4	1.0	1.7	4.9
Colorado Mon.	0.6	0.3	0.8	1.1	0.6	1.5	2.8	7.7

Exhibit 5-4

AIR QUALITY IMPACT OF PICEANCE CREEK FACILITIES ON THE CLASS I AREAS

Mandatory Class I	Piceance Creek Facilities: Occidental	Multi-mineral	Superior	Rio Blanco	Exxon	Total
Flat Tops	1.7	0.7	2.2	1.8	0.9	7.3
Mt. Zirkel	0.7	0.2	0.6	0.4	0.3	2.2
Maroon Bells	0.7	0.3	0.8	0.7	0.3	2.8
West Elk	0.7	0.2	0.7	0.4	0.3	2.3
Arches	0.3	0.1	0.5	0.4	0.2	1.5
Rawah	0.3	0.1	0.3	0.4	0.2	1.3
Eagles Nest	0.3	0.1	0.6	0.4	0.3	1.7
Rocky Mount.	0.3	0.1	0.4	0.4	0.2	1.4
Potential Class I						
Dinosaur	1.4	0.6	1.8	1.4	0.8	6.0
Black Canyon	0.7	0.2	0.7	0.4	0.3	2.3
Colorado Mon.	1.0	0.4	1.2	1.1	0.5	4.2

Exhibit 5-5

AIR QUALITY IMPACT OF UINTA BASIN FACILITIES
ON THE CLASS I AREAS

Mandatory Class I	Uinta Basin Facilities: Moonlake Power	TOSCO	Geokinetics	White River	Paraho	Magic Circle	Syntana	Total
Flat Tops	0.9	0.1	0.3	0.1	0.5	0.1	0.3	2.3
Mt. Zirkel	0.4	0.1	0.0	0.1	0.3	0.1	0.1	1.1
Maroon Bells	0.5	0.1	0.0	0.1	0.3	0.1	0.2	1.3
West Elk	0.5	0.1	0.0	0.1	0.3	0.1	0.2	1.3
Arches	1.1	0.2	0.3	0.1	0.5	0.1	0.3	2.6
Rawah	0.3	0.0	0.0	0.0	0.3	0.1	0.1	0.8
Eagles Nest	0.4	0.1	0.0	0.1	0.3	0.1	0.1	1.1
Rocky Mount.	0.3	0.0	0.0	0.0	0.3	0.1	0.1	0.8
Potential Class I								
Dinosaur	2.9	0.4	0.7	0.3	1.5	0.4	0.8	7.0
Black Canyon	0.6	0.1	0.0	0.1	0.3	0.1	0.2	1.4
Colorado Mon.	1.4	0.2	0.3	0.1	0.8	0.2	0.4	3.4

Piceance Creek facilities is slightly less than that of the Parachute sources. The range of impacts varies from 1.3 ug/m^3 to 7.3 ug/m^3 and only the impacts at Flat Tops and Dinosaur exceed the 24-hour SO_2 increment. Finally, as Exhibit 5-5 illustrates, the Uinta facilities have a minor impact on the mandatory Class I areas but they do combine to violate the increment at the Dinosaur National Monument (7.0 ug/m^3).

One PSD source that has an air quality impact, the Craig electric generating station, is not located in any of the three basins. This station's impact on the Class I areas ranges from 4.6 ug/m^3 at both Flat Tops and Mt. Zirkel to 0.6 ug/m^3 at the Arches National Park.

As indicated in Exhibit 4-3 in the last chapter, there are several cases where plumes from two air basins or one of the basins and the Craig power plant will overlap to impact a Class I area. This interaction occurs because under certain conditions the winds cause the plumes to travel in similar directions. The interactions between sources must be taken into account when determining the cumulative air quality impact in each Class I area.

Increment Violations

Exhibit 5-6 summarizes the cases where the 24-hour SO_2 increment would be violated. These violations represent the air quality impact of all the PSD permitted and proposed sources if they are constructed at their proposed locations. The highest 24-hour SO_2 increment reading is 10.9 ug/m^3 when the Parachute and Piceance Creek sources impact the Dinosaur National Monument. The Flat Tops Class I area constrains the oil shale development in the Parachute, Piceance, and Uinta Creek basins. The highest 24-hour air quality impact at Flat Tops would be 9.6 ug/m^3 when the plumes from the Uinta and Piceance Creek sources interact. Four other areas (Maroon Bells, Mt. Zirkel, Colorado Monument and West Elk) would have impacts that exceed the increment ceiling. The air quality at the remaining mandatory and potential Class I areas would not exceed the 5.0 ug/m^3 increment when all the sources are permitted.

Exhibit 5-6

VIOLATIONS OF THE 24-HOUR
SO_2 AIR QUALITY INCREMENT

Basin	Class I Area	24-Hour Air Quality Impact (ug/m³)
Parachute	Flat Tops	9.2
Uinta -- Piceance	Flat Tops	9.6
Piceance	Flat Tops	7.3
Parachute -- Uinta	Maroon Bells	7.3
Parachute	Maroon Bells	6.0
Uinta -- Craig	Mt. Zirkel	5.7
Piceance -- Parachute	Dinosaur	10.9
Uinta	Dinosaur	7.0
Piceance	Dinosaur	6.0
Parachute	Colorado Monument	7.7
Piceance -- Parachute	West Elk	7.2

Growth Constraints Under FCFS Policy

To evaluate the growth that may be accommodated in this area, it is necessary to estimate the impact of individual sources on each Class I area where violations occur. Assuming that the sources are granted permits in the order of the queue shown in Exhibit 4-5 in Chapter 4, it is possible to estimate how many sources could site before the 5.0 ug/m³ increment is exhausted. An example of this methodology is shown in Exhibit 5-7. The first and second columns list the sources in the Parachute Creek basin in the order in which they are assumed to apply for PSD permits.* The final two columns illustrate the air quality impact of individual sources and their cumulative impact on Flat Tops. The impact of NOSR and Cities Service would push the increment beyond the 5.0 ug/m³ ceiling. Under a FCFS policy these two facilities would not be able to site. Even if the NOSR plant applied SO_2 control beyond the BACT level, it would not sufficiently reduce its air quality impact to obtain a PSD permit. However, if this facility scaled down its operations it could obtain a permit.

The type of evaluation shown in this exhibit was conducted for each mandatory and proposed Class I area. Appendix D includes the calculations that were conducted. Thirteen sources may not be able to obtain permits due to one or more of the Class I areas. Two of these sources (Mobil and Chevron) would be able to obtain permits if the Dinosaur Monument were not considered a Class I area. Eight sources violate the increment at Flat Tops. Although a number of these sources violate the increment at other Class I areas, it is apparent that the Flat Tops Wilderness area may be a major constraint to growth.

A third area, the Mt. Zirkel Wilderness area, might constrain development in the Uinta basin, though accurate air quality projections are not currently possible with the state-of-the-art modeling procedures. The approximate

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* Chapter 4 established the order in which PHB assumes the oil shale facilities would apply for PSD permits. This list is established for illustrative purposes only and is not intended to indicate which sources would be able to obtain PSD permits.

Exhibit 5-7

SOURCES WHICH CANNOT SITE DUE TO
PARACHUTE BASIN FACILITIES' IMPACT ON FLAT TOPS

Parachute Creek Facilities	Order in Permit Queue	Air Quality Impact on Flat Tops	Cumulative Impact
Union	1	0.7	0.7
Colony	2	0.4	1.1
Pacific	9	0.9	2.0
Chevron	14	1.4	3.4
Mobil	15	0.7	4.1
NOSR	17	2.0	6.1
Cities Service	18	3.1	9.2

Circled values represent facilities that violate the 24-hour Class I increment.

results from the air quality modeling conducted for this study indicate the increment at Mt. Zirkel may be consumed by the Craig power plant in Colorado and the Moonlake power plant in Utah. While the Moonlake plant and unit 3 at Craig have both obtained PSD permits, units 1 and 2 at Craig do not have PSD permits but count against the PSD increment nonetheless.*

Even though the air quality modeling for this analysis suggests that Uinta basin development may be limited by possible consumption of the increment in Mt. Zirkel, one should be cognizant that this may not be the case in reality. The Uinta basin sources are such great distances from Mt. Zirkel that current modeling capabilities are severely limited in predicting accurate concentrations. The air quality contributions from these sources at Mt. Zirkel are so small (about 0.1 ug/m^3) that any refinements in the modeling for either the power plants or the oil shale facilities may change the results considerably. Nonetheless, this analysis makes no judgment on the validity of the modeling since there are currently no better models available for this area. Hence, the results from the modeling are used as is in assessing the relative impacts of various management options without making arbitrary adjustments.

All six proposed oil shale sources in the Uinta basin would violate the increment at Mt. Zirkel. The Maroon Bells, West Elk, and Colorado Monument Class I areas also constrain one or two of the proposed oil shale facilities.

The thirteen sources that could not obtain permits represent nearly 75 percent of the total barrels per day (bbl/d) of proposed shale oil development. If only mandatory Class I areas are included, the Chevron and Mobil facilities which would exceed the increment only at Dinosaur would be able to obtain PSD permits. Therefore 465,000 bbl/d of production (7 of the 18 proposed sources) could obtain PSD permits. If Dinosaur is included as a Class I area, the allowed production would drop to 315,000 bbl/d.

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* Units 1 and 2 commenced construction before the applicable date for PSD review but after the applicable date for inclusion of sources in the baseline concentration for PSD purposes.

SO_2 Control Costs

Exhibit 5-8 lists the SO_2 removal efficiencies and annualized SO_2 control costs for the eighteen oil shale facilities that are proposed for this study area. The percent removal efficiencies are based on BACT control assumptions, and the percentages vary depending upon the process employed. The percent removals vary from 95.0 percent for the modified-in-situ process to 99.8 percent for Rio Blanco. Annualized control costs for individual sources range from $5.6 million at Colony to $27.6 million at Occidental. Appendix B includes the methodology that was used to derive pollution control costs for the individual plants. Total SO_2 control costs would be $192.2 million for all the facilities at a BACT control level.

The SO_2 control costs under a FCFS policy would be dependent on the number and types of oil shale facilities that can site in the study area. With just the mandatory Class I areas considered in the analysis, seven sources can obtain PSD permits. These sources would have annual SO_2 control costs of $92.6 million. If Dinosaur is considered a Class I area, only five sources can obtain PSD permits and their annual SO_2 control costs would be $61.9 million.

BASE CASE SUMMARY

The first-come, first-served PSD management approach could constrain development of some oil shale facilities in the Colorado/Utah study area. The oil shale facilities have air quality impacts on a number of Class I areas and, in particular, 6 of the 11 mandatory or proposed Class I areas would exceed the increments if all sources were located at the proposed sites.*

The Mt. Zirkel increment may have already been consumed by two sources (Craig and Moonlake). This situation may constrain future development in the Uinta

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* The six Class I areas are: Flat Tops, Mt. Zirkel, Dinosaur, West Elk, Maroon Bells and Colorado Monument.

Exhibit 5-8

ANNUALIZED SO_2 CONTROL COSTS OF PROPOSED OIL SHALE FACILITIES AT ASSUMED BACT LEVELS

Source	Percent of SO_2 Emissions Removed	Annualized SO_2 Control Cost* (mm mid-1985$)
Union	98.0	11.5
Colony	96.9	5.6
TOSCO	96.9	5.7
Occidental	95.0	27.6
Geokinetics	95.0	7.9
Multimineral	98.0	11.5
White River	98.0	19.2
Superior	96.9	5.7
Pacific	96.9	5.7
Paraho	96.4	4.6
Magic Circle	98.0	7.8
Rio Blanco	99.8	3.5
Exxon	96.9	6.5
Chevron	98.0	19.2
Mobil	98.0	11.5
Syntana	96.9	5.7
NOSR	96.4	17.8
Cities Service	95.0	15.2
Total		192.2

* Annualized costs include the annualized cost of the capital to build the plants and the annual operating costs for the plant.

basin. Fortunately, Parachute and Piceance basin sources do not affect Mt. Zirkel on the same days as the Craig and Moonlake plants, hence, growth in these basins is not constrained by consumption of Mt. Zirkel's increment.

If Dinosaur is included as a Class I area, only 315,300 bbl/d of development (five sources) could obtain PSD permits. If Dinosaur is not included, 465,300 bbl/d of development (seven sources) could obtain PSD permits. These seven sources could obtain permits by installing $92.6 million (annual) in SO_2 pollution control equipment.

Under the current law, if more sources are to obtain PSD permits, the following options are available to the plants and the states:

- States could require all sources to comply with more stringent pollution control technology, thereby providing more increment available to new sources.
- Once the increment was consumed, new sources could purchase air quality offsets to assure that the cumulative air quality impact does not exceed the increment ceiling.
- States could require existing sources to retrofit SO_2 control, thereby lowering baseline concentrations and providing a growth margin for new sources.
- States could require oil shale facilities with PSD permits to retrofit SO_2 control.
- New sources could obtain a variance from the Class I increments.

MOST STRINGENT TECHNOLOGY

This option involves the application of stringent SO_2 control to all sources with pending PSD permit applications. This option would allow more sources to site before the 5.0 ug/m³ increment is consumed, but it will increase SO_2 control costs for the sources obtaining PSD permits. Sources which have already received PSD permits would not be required to install additional control.

For the purposes of this analysis most stringent technology is defined as the maximum amount of SO_2 removal technically feasible. Most stringent technology is equivalent to 99 percent SO_2 removal for plants utilizing the TOSCO process, 98 percent removal for the Paraho, Union and MIS processes, and 99.8 percent removal for the plants using the Rio Blanco process. Stringent technology levels for Rio Blanco and Union are the same as BACT levels.*

Exhibit 5-9 illustrates the air quality impact of the proposed sources on Flat Tops after they have been adjusted for the application of more stringent technology. Flat Tops was chosen because over half of the proposed oil shale sources would violate the increment ceiling under the FCFS policy. The exhibit includes the air quality impact of the sources in each basin. The plumes for the sources in the Uinta and Piceance basins combine to affect Flat Tops.

The application of stringent technology to all of the proposed oil shale facilities reduces the cumulative air quality impact of the sources in comparison to the impact under the FCFS policy. Table 5-1 compares the air quality impact on Flat Tops under the FCFS and a stringent technology approach.

Table 5-1

AIR QUALITY IMPACT OF PROPOSED SOURCES ON FLAT TOPS UNDER FCFS AND STRINGENT TECHNOLOGY

Source Basin(s)	Air Quality Under FCFS Policy (ug/m^3)	Air Quality Under Stringent Technology (ug/m^3)
Parachute	9.2	6.8
Piceance	7.3	5.7
Uinta	2.3	1.7
Piceance/Uinta	9.6	7.4

* The Rio Blanco and Union processes are not known to have SO_2 pollution control options beyond what was assumed for BACT.

Exhibit 5-9

CUMULATIVE AIR QUALITY IMPACT OF PROPOSED SOURCES ON FLAT TOPS WITH MOST STRINGENT TECHNOLOGY POLICY

Source	Parachute	Piceance	Uinta	Uinta/ Piceance
Moonlake			0.9	0.9
Union	0.7			
Colony	0.8			
TOSCO			0.9	0.9
Occidental		0.7		1.6
Geokinetics			1.0	1.7
Multimineral		1.4		2.4
White River			1.1	2.5
Superior		3.6		4.7
Pacific	1.7			
Paraho			1.5	5.1
Magic Circle			1.6	5.2
Rio Blanco		5.4		7.0
Exxon		5.7		7.3
Chevron	3.1			
Mobil Oil	3.8			
Syntana			1.7	7.4
NOSR	5.5			
Cities Service	6.8			

Circled values represent the sources which cause the 5.0 ug/m³ 24-hour increment to be exceeded.

The cumulative air quality impact at Flat Tops decreases. This is also found to be the case at other Class I areas. However, when the air quality impact at all Class I areas is considered, only one new oil shale facility would obtain a permit under the most stringent technology approach than using the FCFS policy. This one source, the Superior 50,000 bbl/d facility, would no longer violate the increment at the Flat Tops Class I area. If only the mandatory Class I areas are included, this policy would allow 515,000 bbl/d of oil shale development. This compares to 465,000 bbl/d under the FCFS management approach. The inclusion of Dinosaur as a Class I area would reduce development to 365,000 bbl/d as opposed to 315,300 bbl/d under the FCFS approach. Appendix E includes a review of the cumulative air quality impact of all the proposed sources on each of the mandatory and potential Class I areas.

Although some additional increment is available to sources under this policy, the plants that must install stringent control incur extra SO_2 control costs. Exhibit 5-10 illustrates the costs that sources would have to pay beyond what they would spend on SO_2 pollution control under the current FCFS policy. Half of the sources would incur extra costs due to the most stringent technology policy.

As the exhibit indicates, the additional costs would be about $108.3 million annually. From a cost perspective this policy requires that sources install additional equipment at an earlier date than would otherwise be the case so that there can be more air quality increment available for future sources. The benefit of these additional costs is extremely small; only one additional oil shale facility can obtain a PSD permit.

AIR QUALITY OFFSETS

In many areas of the country existing and PSD-permitted emission sources can apply additional SO_2 control that would allow more increment to be available for new sources. In this study area the Hayden power plant and the Craig plant (units 1 & 2) are the major sources of potential offsets for the oil shale facilities.

Exhibit 5-10

ANNUALIZED COST COMPARISON BETWEEN FCFS PSD POLICY AND MOST STRINGENT TECHNOLOGY POLICIES*
(mm mid-1985$)

Source	Cost of SO_2 Control Under FCFS PSD Policy	Cost of SO_2 Control Under Most Stringent Technology	Additional Costs of Most Stringent Technology Policy
Union	11.5	11.5	--
Colony	5.6	11.7	6.1
Occidental	27.6	111.5	83.9
Multimineral	11.5	11.5	--
Superior	**	12.0	12.0
Pacific	5.7	12.0	6.3
Chevron	19.2	19.2	--
Mobil	11.5	11.5	--
	92.6	200.9	108.3

* This exhibit includes the sources that can obtain permits when the mandatory Class I areas are evaluated. The inclusion of Dinosaur as a Class I area would cause the Chevron and Mobil facilities to exceed the 24-hour SO_2 increment at Dinosaur.

** Superior cannot obtain a permit under the FCFS policy.

Unit 3 of the Craig plant and the Moonlake generating station cannot install additional control.* The Colony oil shale facility has received a PSD permit and could install additional control but the accompanying reduction in air quality impact at all Class I areas would be minimal. Hence, Colony is not a likely offset supplier. An analysis of SAI's air quality modeling results indicates that the Hayden and Craig plants could provide substantial offsets to sources in the Uinta basin if the need arises.

The PSD policy of choosing the second worst day to calculate an increment violation complicates the offset trading process. Concentrations in excess of 5.0 ug/m³ can occur at both different Class I areas and on different days. Thus, offsets are both time and location dependent. For example, the Hayden plant has a significant impact on Flat Tops but little impact on Arches. A PSD applicant, on the other hand, might have an impact on both Class I areas. By purchasing emission reductions from Hayden, the applicant could offset its impact on Flat Tops, but would have to find a different source of offsets for it's impact on Arches.

The situation is further complicated by the day on which the increment is exceeded. A given location might experience three days per year when concentrations exceed 5.0 ug/m³. An existing source might have an impact on a Class I area during one of these days, but not on the other two. Therefore, the existing source could serve as a source of offsets on only one of the three days of violation. Furthermore, the location and day of the second highest concentration may change as new sources are added to the area. To obtain a permit a new source must ensure that the SO_2 increment on the second worst day at all locations will not exceed 5.0 ug/m³. When a new source would cause increments to be exceeded on a number of days and at several locations, offset trading may involve several sources and could become quite complicated.

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* Unit 3 at the Craig plant plans to install dry scrubbing at 88 percent SO_2 removal efficiency. The Moonlake PSD permit states that this plant will comply with 94 percent control. These requirements represent maximum control capabilities.

Nevertheless, an offset policy may provide the needed air quality reductions to enable additional sources to obtain PSD permits. As discussed previously, Flat Tops, Mt. Zirkel, and Dinosaur are the critical areas that constrain the majority of the oil shale development. No source in the area could provide offsets for Flat Tops or Dinosaur. This conclusion is based on the fact that the Hayden and Craig plants could not provide offsets on days when sources in the Parachute and Piceance basins would exceed the increment at these two Class I areas.*

Offsets can be an effective strategy for the Uinta basin sources which would exceed the Mt. Zirkel increment ceiling. This is due to the interaction of the Uinta sources and two power plants. The Craig plant (units 1, 2, and 3) and the Moonlake plant may have exhausted the allowable increment at Mt. Zirkel.** Hence, any oil shale facility located in the Uinta basin which had an impact on the Mt. Zirkel Class I area could not obtain a PSD permit. If Craig or the Hayden plant were to install additional SO_2 control this would reduce their air quality impact and enable new oil shale facilities to obtain PSD permits. Table 5-2 illustrates the increments that could be available for offset purchases.

Table 5-2

AVAILABLE OFFSETS FROM HAYDEN AND CRAIG AT MT. ZIRKEL

Source	Current SO_2 Control (%)	Current Air Quality Impact on Mt. Zirkel (ug/m^3)	Potential SO_2 Control (%)	Potential Offsets (ug/m^3)
Hayden	0	7.9	60	4.7
Craig	75	4.6	85	1.8

* As has been noted, the Colony plant in the Parachute Creek basin can install additional control, but this additional control would not decrease the increment significantly in these three Class I areas.

** See Appendix D, Exhibit D-4.

The Hayden plant currently has no SO_2 control equipment in place. It is assumed that this plant could retrofit control equipment that would operate at a 60 percent rate of removal efficiency. The cost of this equipment would be $11.8 million on an annual basis. Hayden could also install control to meet less strict removal rates. For example, Hayden could install 30 percent control at an annual cost of $5.7 million. The Craig unit has proposed SO_2 control of 75 percent SO_2 removal. The plant could upgrade its scrubber to operate at 85 percent efficiency. The cost of additional control would be $5.45 million annually. Appendix C describes the methodology used to estimate pollution control costs for utility plants.

If it is assumed that the Hayden or Craig plants would require a 10 percent return on the cost of any pollution control equipment they installed,* then oil shale sources could reduce their air quality impact on Mt. Zirkel by purchasing offsets that would be equivalent to the pollution control costs and the required return. In this case the Hayden plant could provide the least-expensive offsets. At 60 percent control, Hayden could supply 4.7 ug/m^3 of offset for $13 million, or $2.77 million per microgram of increment. The Craig plant would provide offsets at an incremental cost of $3.33 million per microgram.

The purchase of offsets from the Hayden or Craig plants by the Uinta oil shale sources would alleviate the pressure on the increment ceiling at Mt. Zirkel. In fact, the Hayden plant would only have to install 30 percent control ($5.7 million) to accommodate all six of the oil shale sources. However, several of these oil shale sources would still contribute to a violation at other Class I areas. For example, if the Paraho facility purchased an offset from the Hayden plant so that its impact on Mt. Zirkel would be below the increment ceiling

* PHB recognizes that a 10 percent return may be a conservative estimate of the actual premium that offsets may command. If the demand is high or the supply small, offsets may require a much higher premium.

it would still exceed the increment at Flat Tops. Thus, Paraho would not be able to obtain a permit without another offset at Flat Tops. Three Uinta basin sources have increment violations at only the Mt. Zirkel Class I area. Therefore, if these sources purchased offsets, they would be granted PSD permits because they would no longer violate a Class I increment.

Table 5-3 illustrates the difference between the FCFS policy and a FCFS with offsets.

Table 5-3

COMPARISON OF FCFS POLICY
WITH OFFSET OPTION

	FCFS Policy	FCFS with Offsets
SO_2 Control Costs (mm 1985$)	92.6	126.7
Air Quality Impact (ug/m^3)	5.0	5.0
Number of Sources Permitted	7	10
(Thousand bbl/d)	(465)	(635)

The SO_2 control cost increases by $39.1 million due to the cost of the offsets and the SO_2 control cost of the additional sources that can obtain PSD permits. The air quality would be maintained under each approach. The SO_2 increment would be consumed at the Flat Tops and Mt. Zirkel Class I areas, and additional increment would be available at the other parks and wilderness areas. The significant difference is that three additional oil shale facilities could obtain PSD permits if an offset trading market were implemented. This table is based on the sources that could be permitted with only the mandatory Class I areas in the analysis. If Dinosaur were considered a Class I area, five sources (315,000 bbl/d) instead of eight sources (485,000 bbl/d) could obtain PSD permits.

RETROFIT OF EXISTING SOURCES

Existing emission sources can retrofit SO_2 control equipment on their plants and increase the available SO_2 air quality increment. Individual sources would install this equipment if an air quality offset is purchased or if the additional control is mandated by the state. As illustrated previously, the only major existing SO_2 emission source in the oil shale area is the Hayden power plant. This source currently has no SO_2 control. Hayden could retrofit SO_2 control equipment at several control levels. As indicated, a 60 or a 30 percent removal efficiency could be achieved at an annual cost of $11.8 and $5.7 million, respectively.

Reducing the air quality impact of the Hayden plant would provide additional increments for oil shale development. Hayden and the following sources interact to impact different Class I areas:

- Uinta basin sources and Hayden impact Mt. Zirkel,
- Uinta basin sources and Hayden impact Rawah, and
- Piceance Creek sources and Hayden impact Arches.

Exhibits 5-3, 5-4, and 5-5 showed that, even with all of the proposed sources permitted, the increment ceiling is not violated at either Rawah or Arches. Therefore, the only sources that would require, and could obtain, offsets would be the Uinta basin sources when they impact Mt. Zirkel. By retrofitting 30 percent control the Hayden plant would provide the necessary additional increment for the sources in the Uinta basin.

This PSD management option allows the same sources to receive permits as the offset approach. The difference between the options is that the cost of installing retrofit control is borne by the Hayden facility and not by the sources who would purchase offsets. Three additional sources would be allowed to obtain PSD permits if this option were implemented.*

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* Three sources (Paraho, Magic Circle, and Syntana) also would no longer violate the increment at Mt. Zirkel, however they would not receive a permit because they violate the increment at Flat Tops.

RETROFIT OF OIL SHALE SOURCES

A second retrofit option would be to mandate that additional pollution control be retrofitted to oil shale facilities that had already received PSD permits. This option would be implemented after the increment was consumed. The rationale for this approach is that the current facilities should not have to install excessive control until the increment ceiling is reached. Second, there is tremendous uncertainty involved in the current emission estimates for the oil shale facilities. If the estimates have been incorrect, it may be necessary for the state to require that additional control be added. This option, particularly if the ceiling were never reached, would be preferable to a most stringent technology approach because the facilities would not be forced to over control their SO_2 emissions.

The retrofit of oil shale facilities would provide the same outcome as the most stringent technology option, namely that one additional source could obtain a permit. However, if the retrofit were not implemented until the PSD increment was consumed, it may be preferable to the most stringent technology option since additional investment and annual operating costs would be delayed. This option would be cheaper as long as the discounted cost of retrofitting sources is less than the incremental cost of most stringent technology.

VARIANCE APPROACH

In the event that the Class I increments do pose a constraint on energy development, the Act does provide two mechanisms in Section 165(d) by which sources may be granted waivers to Class I increments.

It is difficult to predict with any certainty how much additional growth would be possible under the variance approach because many decisions involve discretionary judgment by the FLM or the governor. However, it should be noted that the 24-hour SO_2 increment of 91 ug/m³ specified in Section 165(d)(2)(c) is 18 times less stringent than the Class I SO_2 increment of 5.0 ug/m³. This implies that as long as the FLM certifies that new sources do not adversely affect air-quality-related values, emissions in the oil shale region could grow substantially while the air quality would still remain well below the health-based primary standard.

Analysis of Section 165(a)(2)(d) showed that the requirement which would allow the increment to be exceeded 18 days per year (rather than just once per year) would be more restrictive than the special increments for high-terrain areas.

A log normal distribution was fit to air quality modeling data to estimate the impact on the eighteenth highest day for the proposed sources. When the increment reaches the 5.0 ug/m^3 ceiling on the eighteenth worst day, the air quality on the second worst day will range from 9.60 to 12.05 ug/m^3.* The most constraining Class I areas for this analysis are Flat Tops and Dinosaur. Under the most conservative assumption (i.e., the distribution in which the second highest day is 12.05 ug/m^3) only one shale source would be denied a permit when the mandatory Class I areas are considered. If Dinosaur is considered a Class I area, two sources would be denied permits. If the lower bound is used all sources could obtain permits before the 5.0 ug/m^3 ceiling was reached on the eighteenth day.

This analysis demonstrates that variances could be granted to a number of sources before the special increment ceiling would be reached. If a variance approach was instituted, SO_2 control costs would be lower because sources would not have to install additional control or purchase offsets. Sources could simply install the required control and apply for a variance. The decreased emission control requirement would result in deteriorating air quality in the Class I areas. If all the sources were allowed to site under Section 165(d)(2)(d), the 24-hour Class I impact on the second worst day could be as high as 12.0 ug/m^3, which is greater than twice the current increment.

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* The range reflects uncertainty in the value for the standard deviation of air quality levels. Upper- and lower-bound values were assumed for this parameter.

Summary of the PSD Management Options
Allowed Under Current Law

The analysis of the base case or current PSD policy indicates that a first-come, first-served approach, without any variations, may constrain oil shale development. The air quality impact of eleven of the proposed eighteen oil shale facilities would exceed the allowable increment at one or more of the mandatory Class I areas. These plants would be denied a PSD permit and only 465,000 bbl/d of development could be sited. If the proposed Class I areas are included in the analysis, thirteen sources would exceed the allowable increment. The five facilities that could receive permits would account for 315,000 bbl/d of oil shale production.

Under current law individual plants and the state have a number of options once the increment is consumed. Exhibits 5-11 and 5-12 compare these options on the basis of SO_2 control cost, air quality impact and the number of sources that could be permitted. Exhibit 5-11 compares the options when the mandatory Class I areas are considered while Exhibit 5-12 compares the options when the potential Class I areas are included with the mandatory areas.

Only one option under the current law (variances) would allow all (or most) of the proposed oil shale facilities to obtain PSD permits. The application of most stringent technology would more than double the SO_2 control costs from the current policy but only one additional source would be able to obtain a PSD permit. Several additional conclusions can be highlighted as a result of this analysis:

- The current FCFS policy will maintain air quality at or below the Class I increment. But some oil shale facilities may need to receive variances to obtain PSD permits.

- If an offset trading market is developed, an additional three sources could receive PSD permits. The offsets required could be obtained from the Hayden power plant.

Exhibit 5-11

COMPARISON OF ALTERNATIVE MANAGEMENT OPTIONS TO CURRENT FCFS POLICY IN THE MANDATORY CLASS I AREAS

Alternatives Under Current Law	SO_2 Control Costs (mm mid-1985$)	Air Quality Impact* (ug/m^3)	Allowed Oil Shale Production** (000)
Current FCFS Policy without Offsets	92.6	5.0	465 (7)
Offsets	126.7	5.0	635 (10)
Retrofit Existing	126.1	5.0	635 (10)
Variance	177.0-192.2	9.30-12	1190-1240+ (17-18+)
Most Stringent Technology	200.9	5.0	515 (8)

* The increment shown in this table represents the air quality at the Class I area with the highest SO_2 concentration.

** The figure in parentheses represents the number of oil shale facilities that could obtain permits.

Exhibit 5-12

COMPARISON OF ALTERNATIVE MANAGEMENT OPTIONS TO CURRENT FCFS POLICY IN THE MANDATORY AND POTENTIAL CLASS I AREAS

Alternatives Under Current Law	SO_2 Control Costs (mm mid-1985$)	Air Quality Impacts* (ug/m³)	Allowed Oil Shale Production** (000)
Current FCFS Policy	61.9	5.0	315 (5)
Offsets	101.0	5.0	485 (8)
Retrofit	98.8	5.0	485 (8)
Variance	177.0-192.2	9.70-12	1190-1240+ (17-18+)
Most Stringent Technology	170.2	5.0	365 (6)
Increment Reservation, and Local Preference	NQ	NQ	NQ

NQ = Not Quantifiable.

* The increment shown in this table represents the air quality at the Class I area with the highest SO_2 concentration.

** The figure in parentheses represents the number of oil shale facilities that could obtain permits.

- The retrofit of existing sources, assuming a coordinated Utah-Colorado policy, would result in the same air quality impact and number of sources permitted as the offset option. The difference in the approaches is that an offset policy forces the sources needing the increment to pay for the offset while a retrofit approach forces the existing facility to pay the retrofit costs.

- Two additional sources would not be able to obtain PSD permits if the Dinosaur National Monument is included as a Class I area. These two sources represent 150,000 bbl/d of lost production. Under all of the alternative management options (except the variance approach) the inclusion of Dinosaur as a mandatory Class I area results in two fewer permitted oil shale facilities.

Changes in the Clean Air Act may allow for some alternative approaches to the prevention of significant deterioration. Such changes are only speculative at this time, and the approaches studied here include only a few possible alternatives. They are:

- Eliminate short-term increments but retain the annual increment,
- Eliminate short-term increment tracking, and
- Replace the Class I increment with BACT requirement.

ANNUAL AIR QUALITY INCREMENT

This approach would do away with the short-term increments and retain only an annual increment. This approach would require that the Clean Air Act be amended. The justification for this change is: 1) the annual increment would protect the long-term air quality at the park without needlessly constraining new industrial development; and 2) modeling short-term increments is difficult and uncertain.

SAI, Inc. conducted the air quality modeling required to estimate the impact of existing sources, PSD permitted sources and proposed sources for the study area. Exhibit 6-1 lists the annual average SO_2 concentrations for each

Exhibit 6-1

ESTIMATED ANNUAL AVERAGE SO_2 CONCENTRATIONS AT MANDATORY AND POTENTIAL CLASS I AREAS FROM PROJECTED ENERGY DEVELOPMENT

Mandatory Class I Areas	Annual Average Concentrations (ug/m³)
Flat Tops	0.62
Mt. Zirkel	0.33
Maroon Bells	0.13
West Elk	0.10
Arches	0.04
Rawah	0.09
Eagles Nest	0.12
Rocky Mountain	0.14
Potential Class I Areas	
Dinosaur	0.07
Black Canyon	0.04
Colorado Monument	0.16

of the mandatory and potential Class I areas. These totals represent the cumulative impact of <u>all</u> of the PSD and proposed sources. The basins in which these sources are located are combined in this analysis because all sources will impact the Class I areas during the course of the year.

The highest overall annual SO_2 concentration would be 0.62 ug/m^3 the Flat Tops Class I area. The remaining Class I areas have annual concentrations ranging from 0.04 at Arches to 0.33 ug/m^3 at Mt. Zirkel. Because the annual increment ceiling is 2.0 ug/m^3, it appears that all of the proposed oil shale facilities and substantial future growth could be accommodated if the Clean Air Act were changed to eliminate the short-term increments.

While this alternative represents a substantial relaxation to the existing program, it still would result in the sources contributing very low absolute concentrations to the mandatory and potential Class I areas. If all of the sources obtained permits, maximum total annual average SO_2 concentrations, including the existing Hayden facility, would be 0.68 ug/m^3. The highest second day 24-hour concentration would be 13.6 ug/m^3.*

ELIMINATION OF SHORT-TERM
INCREMENT TRACKING

A similar option which is currently under consideration by Congress would be to evaluate the cumulative air quality impact with respect to the annual increment and eliminate the comparison of cumulative air quality impact with short-term increments. However, the impact of any source would be evaluated with respect to the short-term increments. No source examined in this study (with their currently proposed controls) would have an air quality impact exceeding 5.0 ug/m^3 -- the 24-hour

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* This 24-hour SO_2 air quality impact occurs when the Uinta Basin, Craig and Hayden sources interact to impact Mt. Zirkel. Hayden is responsible for 7.9 ug/m^3 of this total impact.

SO_2 increment.* Hence, the impact of this option would be the same as the annual increment option.

BACT CONTROL WITH NO
CLASS I INCREMENT

This option assumes there would be no Class I PSD increments. To receive a permit, sources would have to comply with BACT requirements. Obviously no air quality offsets would need to be purchased and plants would not have to apply for air quality variances to receive permits. Under this option no source would be denied a permit provided it met the BACT requirements.

Exhibit 6-2 summarizes the difference between the current first-come, first-served PSD strategy and the BACT policy. Their differences include the annual SO_2 control costs, deterioration of air quality and the number of sources that can receive a permit.

If no PSD Class I increment policy existed, SO_2 control costs would be increased by close to $100 million. However, all sources would receive PSD permits. Accompanying this growth would be a deterioration of the air quality in the Class I areas. If Dinosaur is considered a Class I area the maximum air quality impact would be 10.9 ug/m³. The highest 24-hour impact at a mandatory Class I area would be 9.6 ug/m³ at Flat Tops.

The BACT alternative requires all sources to meet a technology standard. This places the same relative burden on all sources. The current FCFS policy forces individual sources to pay for additional control beyond BACT requirements once the increment is consumed. Hence, the incremental costs of the current policy are borne by the sources seeking to obtain permits. On the other hand, existing sources incur no costs due to the current policy and could actually benefit since they may earn a return by selling offsets. Therefore, it appears that the BACT policy is more equitable than the current policy.

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* The existing Hayden facility has an air quality impact which exceeds 5.0 ug/m³, but only PSD sources are included in this analysis.

Exhibit 6-2

COMPARISON OF BASE CASE AND BACT POLICY OPTION FOR PROPOSED SOURCES IN THE STUDY AREA

	Current FCFS Policy (only mandatory Class I Areas)	Current FCFS Policy (mandatory and potential Class I areas)	BACT Policy**
Annual Cost (mm$)	92.6	61.9	192.2
Maximum Deterioration of Class I Air Quality (ug/m³)	5.0	5.0	10.9
Oil Shale Production Permitted* (M bbl/d)	465 (7)	315 (5)	1240 (18)

* The figures in parentheses represent the number of sources which could obtain PSD permits.

** The BACT policy would allow for development until the secondary NAAQS. The cost, air quality and production estimates are representative of just the currently proposed facilities.

However, the drawback is that a certain amount of air quality is sacrificed.

As additional sources are added, the cost and air quality differential will increase. Given the existing number of sources that are seeking to develop oil shale reserves, the 24-hour SO_2 increment would increase to 9.6 ug/m³ at Flat Tops and 10.9 ug/m³ at Dinosaur. The BACT policy would allow for future growth up to the secondary NAAQS in the area while the current PSD policy may limit growth but would not allow air quality in Class I areas to exceed the increment.

SUMMARY

Exhibit 6-3 summarizes the differences between the current first-come, first-served PSD policy and three alternatives to the Clean Air Act. The current policy would allow for the fewest sources to become permitted and therefore the SO_2 control costs would be low. The annual increment approach and the elimination of short-term tracking approach would allow for additional sources to become permitted, while a BACT policy would allow for unlimited growth.

All three of these alternatives would allow air quality to exceed the 24-hour increment. With the currently proposed sources, short-term air quality could deteriorate to 9.6 ug/m³ at Flat Tops and 10.9 ug/m³ at Dinosaur. There is a clear tradeoff between the number of sources that can be granted permits and the short-term air quality in Class I areas.

Exhibit 6-3

COMPARISON OF ALTERNATIVES TO THE CLEAN AIR ACT WITH THE FCFS PSD POLICY FOR THE PROPOSED OIL SHALE FACILITIES

	SO_2 Control Cost (mm 1985$)	Deterioration of Class I Air Quality (ug/m³)	Sources Permitted
FCFS Policy	92.6	5.0	7
Annual Increment	192.2	9.60 - 10.9	18+
Elimination of Short-Term Tracking	192.2	9.60 - 10.9	18+
BACT	192.2	9.60 - 10.9	18+

SUMMARY AND CONCLUSIONS CHAPTER 7

This report has focused on alternative policies for granting permits to new sources of air pollution located near national parks and wilderness areas. The current PSD policy may limit the development of energy sources that are located near these areas. This chapter includes a review of the caveats and limitations of the analysis, a summary of the results of the analysis and a strategy that may reconcile the tradeoff between oil shale development and air quality deterioration. The results of the analysis will be illustrated by comparing the SO_2 control costs, air quality impact and development implications of the alternative management options to the current first-come, first-served policy approach.

CAVEATS AND LIMITATIONS OF THE ANALYSIS

The major limitation to this analysis is that the database of information on oil shale processes is extremely limited. Information in the following areas was difficult to quantify:

- The SO_2 emissions and air quality impact of the individual oil shale facilities,
- The pollution control costs for oil shale facilities, and

- The proposed development of oil shale sources and the order in which individual plants would apply for permits.

This section will discuss each of these data problems and illustrate how the uncertainty would affect the conclusions of the study.

SO_2 EMISSIONS AND AIR QUALITY

At this time, SO_2 emission estimates for individual oil shale facilities are very difficult to determine. Because no full scale plants have been built, estimates of air emissions must be based on design information, pilot plant tests and laboratory studies. Furthermore, many sources have not chosen the exact shale-processing technology they will use. Where possible, PHB used emission-based design information from the PSD permits or from information supplied by EPA personnel. This appears to be the most current and dependable data that is available. Emission estimates, though still somewhat uncertain, have been refined through studies by the companies and EPA.

An example of the uncertainty associated with SO_2 emission estimates concerns the question of whether oil shale facilities will include refinery operations on site. Virtually all reports on emission estimates have indicated that full-scale refining of shale oil will occur off site and these emissions are not included in the oil shale estimates. However, available PSD permit information indicates that the Union facility will have a full-scale refining operation on site. This same information indicated that SO_2 emissions from the refinery would account for approximately 10 percent of total plant SO_2 emissions. Increasing emissions by 10 percent at all plants using the Union process would <u>not</u> change our conclusions regarding the impacts of the current PSD policy. If all oil shale plants were to include full-scale refining emissions, and the refinery emissions were larger than expected, this could alter several of the conclusions.

As discussed in Chapter 5 there are a number of caveats pertaining to the air quality modeling that was done by SAI. These caveats illustrate that, even using the most sophisticated air quality models, the results are far from certain. The combination of the uncertain stack parameters for the facilities along with the complex terrain in this study area makes any air quality results speculative. Coupling the preliminary emission estimates with crude air quality modeling is a serious handicap for this analysis.

POLLUTION CONTROL COSTS

The lack of data on individual plant SO_2 control costs is due to an absence of operational experience with control equipment for this new technology. PHB attempted to obtain cost estimates for several control levels for each type of oil shale process. Estimates were obtained from PSD permit information and EPA documents. This data, although limited, was used to illustrate the cost differences between options. This information helps determine the relative differences in cost between options but should not be used to base any decision regarding the cost of control at individual sources.

PROPOSED DEVELOPMENT AND
ORDER OF PRODUCTION QUEUE

The results of this study are most useful for comparing alternative PSD management options and not for determining which sources would be able to obtain PSD permits. This caveat is based on the fact that it is nearly impossible to determine in what order individual sources will file for permits and in fact whether some sources will ever commence construction. Because of the tremendous uncertainty involved in process technology and financial structure of this industry it is purely speculative to develop any type of production forecast and permit queues. The conclusions of this study should not be construed to indicate which sources would obtain permits, rather, the focus is to indicate which alternatives would facilitate oil shale development and maintenance of air quality in Class I areas.

These three general limitations of the analysis are substantial but they do not detract from the overall conclusion of the analysis. The exact number of oil shale barrels per day which can be permitted cannot be accurately predicted. However, alternative PSD management options can still be compared and an optimal permitting strategy can be devised.

RESULTS OF THE ANALYSIS

Exhibit 7-1 lists the PSD management alternatives that PHB has evaluated. These alternatives can be grouped into those that are allowed under current law and those that require changes to the Clean Air Act. As can be seen in the exhibit, only four options allow for the majority of the eighteen oil shale sources to obtain a PSD permit in the study area: variance, annual increment, elimination of short-term tracking, and BACT. This exhibit summarizes the results of each option in relation to the mandatory Class I areas. Exhibit 7-2 reviews the same alternatives but it includes the potential Class I areas along with the mandatory areas. Under current law only the variance approach would allow for the majority of facilities to obtain permits. Each of the annual approaches and the BACT option would also allow all sources to receive a permit. Exhibit 7-3 lists the barrels per day of production that could be accommodated under each alternative.

The BACT approach would offer growth potential until the secondary NAAQS was reached, while the most stringent technology, offset and retrofit options would allow for a limited amount of production beyond the current FCFS policy. It is apparent from evaluating Exhibits 7-1 and 7-2 that no options would accommodate all the proposed development and maintain the air quality at the Class I areas. The options that facilitate the permitting of all sources allow the air quality to deteriorate. Conversely, the alternatives that maintain air quality limit growth. In an effort to reconcile this conflict PHB evaluated a combination of the variance and offset management options.

VARIANCE/OFFSET COMBINATIONS

The three mandatory and potential Class I areas that constrain the majority of the oil shale growth are the Flat Tops, Mt. Zirkel and Dinosaur (proposed) parks. None

Exhibit 7-1

COMPARISON OF ALTERNATIVE MANAGEMENT OPTIONS IN THE MANDATORY CLASS I AREAS

Alternatives Allowed by Current Law	SO_2 Control Costs* (mm mid-1985$)	Air Quality Impact (ug/m³)	Number of Oil Shale Sources Permitted
Current FCFS Policy without Offsets	92.6	5.0	7
Most Stringent Technology	200.9	5.0	8
Offsets	126.7	5.0	10
Retrofit Existing	126.1	5.0	10
Retrofit Permitted Sources	200.9	5.0	8
Variance	177.0-192.2	9.30-12.05	17-18+
Increment Reservation, Local Preference	NQ	NQ	NQ
Alternatives Requiring Changes to Current Law			
Annual Increment	192.2	9.6	18+
Annual--Elimination of Short-Term Tracking	192.2	9.6	18+
BACT	192.2	9.6	18+

NQ = Not quantifiable.

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* Annualized costs include the annualized cost of the capital to build the plants and the annual operating costs for the plant.

Exhibit 7-2

COMPARISON OF ALTERNATIVE MANAGEMENT OPTIONS TO CURRENT FCFS POLICY IN THE MANDATORY AND POTENTIAL CLASS I AREAS

Alternatives Under Current Law	SO_2 Control Costs* (mm mid-1985$)	Air Quality Impact (ug/m³)	Number of Oil Shale Sources Permitted
Current FCFS Policy without Offsets	61.9	5.0	5
Most Stringent Technology	170.2	5.0	6
Offsets	101.0	5.0	8
Retrofit Existing	98.7	5.0	8
Retrofit Permitted Sources	170.2	5.0	6
Variance	177.0-192.2	9.70-12.05	17-18+
Increment Reservation, Local Preference	NQ	NQ	NQ
Alternatives Requiring Changes to Current Law			
Annual Increment	192.2	10.9	18+
Annual--Elimination of Short-Term Tracking	192.2	10.9	18+
BACT	192.2	10.9	18+

NQ = Not quantifiable.

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* Annualized costs include the annualized cost of the capital to build the plants and the annual operating costs for the plant.

Exhibit 7-3

POTENTIAL OIL SHALE PRODUCTION
UNDER PSD ALTERNATIVE OPTIONS

Alternative	Potential Production Including Mandatory Class I Areas (Thousands bbl/d)	Potential Production Including Mandatory and Potential Class I Areas (Thousands bbl/d)
Current FCFS Policy	465	315
Most Stringent Technology	515	365
Offsets	635	485
Retrofit Existing	635	485
Retrofit Permitted Sources	515	365
Variance	1190-1240	1190-1240
Annual Increment	1240+	1240+
Annual--Elimination of Short-Term Tracking	1240+	1240+
BACT	1240+	1240+

of the alternatives allowed under current law except the variance option would allow for more than ten oil shale facilities to receive permits. If variances were allowed for sources at Flat Tops only, the air quality would be maintained at the remaining ten mandatory and potential Class I areas and no sources would be denied due to Flat Tops. The maximum 24-hour SO_2 concentration with all sources permitted would be 9.6 ug/m^3 at the park.

The Mt. Zirkel Class I area may constrain the development of the oil shale plants that are located in the Uinta basin. Those sources can obtain air quality offsets at a relatively low cost from either the Hayden or the Craig electric generating stations. If offsets were purchased by these sources, the Mt. Zirkel Class I area would not act as a constraint to development.

If this combination approach were implemented, and only the mandatory Class I areas were included in the evaluation, sixteen of the eighteen oil shale plants representing 990 Mbbl/d could obtain PSD permits and only the air quality at Flat Tops would deteriorate beyond the 5.0 ug/m^3 increment.* This alternative helps to form a compromise between the goal of allowing development and maintaining the air quality at Class I areas.

A problem arises when the proposed Class I areas are included in the evaluation. Although Black Canyon and the Colorado Monument do not act as constraints to growth, the Dinosaur National Monument would constrain half of the proposed sources under a FCFS option. No offsets or retrofit of sources would allow for additional growth. Therefore, even with variances allowed for Flat Tops and offsets purchased for sources impacting Mt. Zirkel, the inclusion of Dinosaur would limit oil shale development to nine sources and 535,000 bbl/d. If variances were granted for the sources that violate the increment at Dinosaur or if Dinosaur were not considered a Class I area, this combination of options would allow sixteen sources to obtain permits with an annual production of nearly one million barrels per day.

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* The Maroon Bells and West Elk Class I areas would act as a constraint to the remaining two. No offsets or retrofit of sources would alleviate this constraint.

CONCLUSIONS

Having discussed the combination variance/offset approach and after evaluation of the other alternatives, the following conclusions can be made:

- Air quality modeling indicates that all of the proposed oil shale facilities in the Colorado/Utah study area could not receive PSD permits without violating the Class I increments at one or more Class I areas. Under the current FCFS policy, only 465,000 barrels per day of development (seven sources) could obtain PSD permits when the mandatory Class I areas are considered. If the Dinosaur National Monument is included as a Class I area, only 315,000 bbl/d (five sources) could obtain permits. Two power plants which have already obtained PSD permits have consumed the Class I increment at the Mt. Zirkel Wilderness area. Future oil shale development in the Uinta basin will be constrained unless variances or offset can be obtained.

- The combination of the variance and offset approaches would help to maintain the air quality at the majority of the Class I areas and it would allow substantial development. If variances were allowed for only the Flat Tops Class I area and offset trading was encouraged for the sources that violate the increment at Mt. Zirkel, sixteen oil shale sources (one million bbl/d) could obtain PSD permits. This conclusion assumes that the Dinosaur area is <u>not</u> considered a Class I area. If the Dinosaur Monument is included as a Class I area, it would constrain development to 535,000 bbl/d even with variances and offsets at Flat Tops and Mt. Zirkel. Additional variances for sources violating the increment at Dinosaur would be required or development would be constrained.

- Due to the small number of sources in the area, there is a limited amount of air quality offsets available for new sources. The purchase of offsets would allow three additional oil shale facilities to obtain PSD permits. Oil shale development would therefore be 635,000 bbl/d or 485,000 bbl/d if Dinosaur is included as a Class I area.

- If the state required existing emission sources to retrofit SO_2 controls, the maximum oil shale production would be identical to the offset approach. The primary difference between the two options is that under an offset approach the sources that require permits pay for the pollution control, while under a retrofit strategy the existing source must pay for the necessary equipment. The evaluation of this retrofit approach assumed that the states of Colorado and Utah would enact a consistent retrofit strategy.

- Other PSD management approaches allowed by current law, including most stringent technology and increment reservation, would also limit oil shale development and would place significant additional costs on the sources that could obtain permits. For example, if more stringent technology were required for all sources, only one additional source (beyond the current first-come, first-served strategy) would receive a permit. The costs of installing stringent technology would approximately double the costs of installing BACT control. Total annualized costs for pollution control for the permitted sources would increase from $92.6 to $200.9 million.

- A final option allowed under current law, the granting of Class I variances, would allow the majority of proposed oil shale sources to obtain PSD permits. This development would be accompanied by higher SO_2 concentrations at the Class I areas. It is difficult to quantify how much growth could take place under a variance approach since Section 165(d) calls on the federal land manager of the park, and in certain cases, the governor of the state or the president, to make subjective decisions regarding the impact on air-quality-related values in these areas. However, under the requirements of the variance procedures, a minimum of nearly 1,200,000 bbl/d of oil shale development could take place. This amount of growth would correspond to a 24-hour SO_2 concentration of approximately 9.6 ug/m³ at Flat Tops and 10.9 ug/m³ at the Dinosaur National Monument.

- Elimination of short-term increments while retaining the annual increment would also allow more energy development to take place in the region. If all the proposed sources were to obtain PSD permits, the highest annual increment reading would be 0.62 ug/m³ at Flat Tops. The coinciding 24-hour increment at Flat Tops would be 9.6 ug/m³. The elimination of short-term increment tracking would have no effect because no individual PSD source has a 24-hour impact of over 5.0 ug/m³. Thus, this option would have the same impact as the annual increment.

- A policy which would eliminate PSD increments and require sources to comply with BACT requirements would degrade air quality at the park but would allow for unlimited development. If this approach were implemented, the 24-hour increment would be 9.6 ug/m³ and 10.9 ug/m³ at the Flat Tops and Dinosaur areas, respectively. The control costs for the sources would also be less because no offsets or additional control would need to be purchased.

ADDITIONAL RESEARCH

PHB has evaluated the impact of alternative PSD management options in this study area as well as in a previous report that focused on alternatives for the state of North Dakota.* Eash of these studies was hampered to a degree by a lack of reliable and consistent air quality modeling data. In particular, the current modeling of air quality in high terrain areas, such as Colorado and Utah, is very unsophisticated. Because the PSD permitting process relies so heavily on modeling results, it is crucial that further research be conducted to make the air quality modeling as accurate as possible.

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* Putnam, Hayes & Bartlett, Inc., Preliminary Assessment of Alternative PSD Management Approaches: A Case Study Based on the Experiences in Western North Dakota, April 1982.

DESCRIPTION OF SOURCES APPENDIX A

The Class I areas in western Colorado and eastern Utah will probably be impacted by emissions from the 18 oil shale facilities and 3 electric utilities modeled in this study. This appendix describes each oil shale source: its location, production characteristics and permit status.

OIL SHALE FACILITIES

Parachute Creek

The Parachute Creek basin lies to the west of Rifle, Colorado, in Garfield County, approximately 60 kilometers from the Flat Tops Wilderness area and about 100 kilometers from the Dinosaur National Monument. Seven oil shale plants are proposed for the basin.

Naval Oil Shale Reserve/Navy and DOE

The Naval Oil Shale Reserve (NOSR) site is located in the eastern part of the basin. It is owned jointly by the Navy and the Department of Energy. Although an initial production date has not been announced, the proposed plant is expected to produce 200,000 bbl/d using the Paraho surface retorting technique. Applications for a PSD permit have not been filed.

Union/Union Oil Company

The Union project, also known as the "Parachute Creek" or "Long Ridge" project, is owned by the Union Oil Company of California and located in the eastern part of Parachute Creek Basin. Initial production of 10,000 bbl/d is projected for 1983, scaling up to full production of 50,000 bbl/d in 1987. The Union-B surface retorting process will be used. A PSD permit was granted in 1979 for the initial production of 9,000 bbl/d. In June 1981 a second PSD permit was granted for a 10,000 bbl/d shale oil refining operation.

Colony/TOSCO and Exxon

Owned by TOSCO Oil Shale Corporation and Exxon, the Colony Project was the first commercial oil shale facility to prepare a final environmental impact statement (EIS) and to receive all critical federal and state permits necessary to commence construction. The project, located about 15 miles north of Parachute Creek, will employ the TOSCO II surface retorting process and on-site hydro treating of raw shale oil. Initial production is expected in 1987, and will eventually reach 48,300 bbl/d.

Chevron Oil

Chevron Oil Shale Company owns a 43,000-acre site in the Roan Plateau area of northwestern Colorado. Feasibility studies are being conducted to evaluate retorting technologies and environmental impacts but no information exists on the proposed technology and an environmental impact statement has not been submitted. The site is expected to begin producing 50,000 bbl/d in 1988 and reach full production of 100,000 bbl/d by 1992.

Mobil Oil

The Mobil Oil Shale Project is owned by Mobil Oil Corporation and is located about 10 miles west of Rifle. Mobil plans to use underground mining and one or more different retorting processes to produce 50,000 bbl/d by 1990. They are involved in preliminary discussions with state officials to clarify permitting requirements and have not yet applied for a PSD permit.

Cities Service

The Cities Service Corporation has not begun development on its Parachute Creek Basin site nor has it applied for any permits. They are expected to use an MIS process to produce 50,000 bbl/d but no production date has been set.

Pacific/Standard

The Pacific Oil Shale Project is jointly owned by Standard Oil of Ohio (60 percent), Cleveland-Cliffs Iron Company (20 percent) and Superior Oil Company (20 percent). The first module is expected to be completed in 1986, producing 15,000 bbl/d. By 1990 the project will produce 45,000 to 50,000 bbl/d using the Superior Oil/Davy McKee surface retorting technology. Environmental impact statements are currently underway.

Piceance Creek

Piceance Creek basin is in Rio Blanco County and lies to the north of Parachute Creek, about 40 miles west of Flat Tops and 45 miles south of the Dinosaur National Monument. The basin is the site of five proposed oil shale projects.

Occidental

Owned jointly by Occidental and Tenneco, Cathedral Bluffs has already received a PSD permit (December 1977) for preliminary production of 5,000 bbl/d. The application for a permit allowing 118,000 bbl/d was submitted in April 1981 but has subsequently been withdrawn. The project is expected to produce 55,000 bbl/d by 1988 and 94,000 bbl/d by 1990. The Oxy-modified-in-situ technology combined with surface retorting will be employed.

Rio Blanco

The Rio Blanco Oil Shale Company has secured PSD permits to test two technologies at this site. A permit was granted in December 1977 for a modified-in-situ project producing 1,000 bbl/d. In July 1981 another PSD permit was granted to test the Lurgi surface retorting process at a production level of 2,000 bbl/d. The commercial project will have a maximum production capacity of 135,000 bbl/d and is expected to begin producing at a level of 76,000 bbl/d in 1987 using the Lurgi technology.

Exxon

Exxon Corporation's Love Ranch project will be developed in two modules, each producing 30,000 bbl/d. Room and pillar mining with surface retorts (TOSCO II) are expected to be in operation for the first module in 1987. Exxon has not yet applied for a PSD permit for the project.

Superior

The Superior Oil Company owned project will employ a proprietary retort process, known as traveling grate, combined with retorted shale leaching. Initial production of 11,600 bbl/d is expected to begin in 1986, eventually increasing to 50,000 bbl/d. A PSD permit application has not been submitted.

Multimineral

The Multimineral Corporation (MMC) plans to use a new mining process, "intensive in situ," in the Horse Draw project to recover several minerals as well as shale oil. MMC is in the first of three stages demonstrating their variation of the modified-in-situ technology. The stages are: experimental mining, modular testing, and commercialization. Production of shale oil is expected to begin in 1984 and reach 50,000 bbl/d in 1986. Environmental impact statements are not yet prepared.

Uinta Basin

Located in Uinta County, Utah, the Uinta Basin is about 50 miles south of the Dinosaur National Monument and 100 miles west of Flat Tops Wilderness area. Six oil shale facilities are planned in the region.

Geokinetics

Owned by Geokinetics, Inc. and supported by DOE, this project has already received a PSD permit (November 1980) for a 100 bbl/d field test of the true in-situ method. Permit applications for commercial production are pending approval. Horizontal modified-in-situ will be used to produce 20,000 bbl/d commercially.

TOSCO/Sand Wash

The Oil Shale Corporation (TOSCO) applied for a PSD permit in August 1981 to produce 45,000 bbl/d at this site. TOSCO II surface retorting operations are expected to begin in 1983 and be producing at full capacity in 1990.

White River/Phillips and Sunoco

Phillips Petroleum Company and Sunoco Energy Development Corporation jointly own this project. They applied for a PSD permit for a pilot plant in August 1981 and expect initial production of 16,000 bbl/d in 1985. Superior and Union surface retorting technology is expected to produce 100,000 bbl/d at full sale.

Paraho

Paraho Development Corporation and design program sponsors own this site and plan to begin construction in 1982. Full operation in 1986 will produce 30,000 bbl/d using the Paraho surface-retorting technique. PSD permit applications have not been submitted.

Magic Circle

Owned by the Magic Circle Energy Corporation, the Cottonwood Wash Project is expected to begin production late in 1986 and be producing 30,000 bbl/d at full scale in 1988. Magic Circle plans to employ a Union-type process for the recovery of shale oil. As yet, no permit application has been filed.

Syntana

The Syntana project is jointly owned by the Synthetic Oil Corporation and Quintana Mineral Corporation. Construction will begin in 1984 and initial production is not expected until the 1990s.

Since there are no facilities that commercially produce oil from shale in the world today, the cost and emission estimates are not based on actual experience. Instead, cost estimates have been evaluated from a variety of sources including published reports, internal EPA documents, and oil shale PSD permit applications. The figures provided by these different sources differ, sometimes dramatically, indicating much uncertainty with regard to expected costs. Three major categories of uncertainty are responsible for most of the discrepancies in cost estimates and the difficulties encountered in selecting costs for this report.

- Uncertainty associated with production processes:
    - In some cases the process that will be employed has not been chosen or has not been analyzed.
    - Whether or not refining facilities exist at each site is uncertain.
- Uncertainty associated with shale:
    - The sulfur content of shale and the composition of emissions vary across the region. Two similar processes handling different qualities of shale could have different control costs.

- Uncertainty associated with control processes:

    - The BACT control levels used in this analysis are assumed only for purposes of this study. Actual BACT determinations for individual sources will be determined on a case-by-case basis.

These uncertainties are mentioned throughout this appendix along with the assumptions used to estimate costs.

PRODUCTION PROCESSES

Oil shale can be processed in one of three basic ways:

- In-situ: The deposit is fractured and pyrolized while in the earth. The shale oil and gases are recovered through wells. This process is not currently commercially feasible.

- Modified-in-situ (MIS): A fraction of the shale is mined to create a void for blasting. Then, heat is applied to the rubblized deposit and oil and gases are recovered through wells.

- Mining and Surface Retorting: Shale is mined and brought to the surface for retorting.

Several variations on the latter two process types are being proposed for the eighteen oil shale sites. Since cost and emission information is not available for each specific process, each facility has been classified, for purposes of this study, into five process categories. These five categories were chosen because they are representative of most currently proposed processes and because either a PSD permit application or an internal EPA document exists which describes applicable control technologies, costs and emissions. The five categories are listed below. The processes in parentheses are representative processes for which information was available.*

- External Indirectly Heated Retort (Union B): Heat is transferred by gases that are heated outside of the above-ground retort vessel.
- Internal Indirectly Heated Retort (TOSCO II): Heat is transferred by mixing hot solid particles with the oil shale in a surface retort.
- Modified-in-situ (Occidental): As described earlier.
- Modified-in-situ and Lurgi (Rio Blanco): MIS is used in combination with a Lurgi Batch surface retorting technology.
- Directly Heated Retort (Paraho): "Heat is transferred by hot gases generated within the retort by combustion of retorted shale and pyrolosis gases."

Exhibit B-1 lists each proposed oil shale facility with its process classification. Several of the companies are uncertain of the process they will use and some of the processes were difficult to categorize neatly. Thus, the costs obtained using these classifications may prove to be incorrect *ex poste*. Yet, they are the best estimates given limited available information.

With the exception of the Union permit application, upgrading facilities were not mentioned in the cost and emission literature. The figures used in this analysis therefore do not normally include emissions from upgrading facilities. Sensitivity analysis was performed which included emissions from upgrading facilities for Union B type processes.

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* PSD permit applications were used for the Union B process and Occidental's MIS process. Internal EPA documents were used for TOSCO II, Rio Blanco, and Paraho.

Exhibit B-1

OIL SHALE FACILITIES BY PROCESS TYPE

Oil Shale Facility	Assumed Process Type
Union	External Indirect Heat
Colony	Internal Indirect Heat
TOSCO/Sand Wash	Internal Indirect Heat
Occidental	Modified-in-Situ (MIS)
Geokinetics	MIS
Multimineral	External Indirect Heat
White River	External Indirect Heat
Superior	Internal Indirect Heat
Pacific	Internal Indirect Heat
Paraho	Direct Heat
Magic Circle	External Indirect Heat
Rio Blanco	MIS and Lurgi
Exxon	Internal Indirect Heat
Chevron	External Indirect Heat
Mobil	External Indirect Heat
Syntana	Internal Indirect Heat
Naval Oil Shale Reserve	Direct Heat
Cities Service	MIS

CONTROL TECHNOLOGIES

EPA technical studies on alternative oil shale technologies discuss pollution control equipment that would be suitable for TOSCO II, Rio Blanco, and Paraho. PSD permit applications for Occidental (MIS) and Union provide surveys of control technologies that would be applicable to those processes. The Colony facility, using the TOSCO II process, has already been granted a PSD permit to use amine absorption for SO_2 control. Therefore, amine absorption is, by definition, BACT. BACT is not defined for the other four process categories, however, nor is stringent BACT. Exhibit B-2 lists each category with the control technologies this analysis assumes to be BACT and stringent BACT.

CONTROL COSTS

Capital costs and annual operating costs are available for each process category.* Capital recovery factors (CRFs) were taken from EPA source literature for four of the five categories. Since the CRFs were very similar for these four categories, an average CRF was applied to the fifth category (Union B) to estimate its annualized costs. The costs are listed in Exhibit B-3 and the CRFs for each process are listed in B-4.

The costs in Exhibit B-3 were derived for five specific facilities. The sizes of the facilities are listed in parentheses on the table. To assign costs to facilities of different sizes, the costs in Exhibit B-3 were scaled according to the engineering cost equation discussed in Exhibit B-5.

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* Costs are from Occidental and Union PSD permits and internal EPA documents.

Exhibit B-2

Process Category	Control Level	Control Technology	Removal SO_2 Efficiency
External Indirect Heat (Union B)	BACT	Stretford Treating	98.0%
Internal Indirect Heat (TOSCO II)	BACT	Amine/Claus/Scot	96.9%
	Stringent BACT	Stretford Treating	99.0%
MIS (Occidental)	BACT	Stretford Treating	95.0%
	Stringent BACT	Organic Sulfur Converted Stretford	98.0%
MIS and Lurgi (Rio Blanco)	BACT	Stretford Treating	99.8%
Direct Heat (Paraho)	BACT	Stretford Treating	96.4%
	Stringent BACT	Amine/Claus/Scot	97.1%

Exhibit B-3

SO_2 CONTROL COSTS FOR OIL SHALE FACILITIES*

Size (bbl/d)	SO_2 Removal Efficiency	Capital Cost ($mm)	Annual Cost ($mm)	Annualized Cost ($mm)
Internal Indirect Heat (47,000)				
BACT	96.9	15.00	3.03	5.49
Most Stringent Technology	99.0	25.70	7.33	11.54
External Indirect Heat (10,000)				
BACT	98.0	13.30	1.37	3.55
MIS (117,000)				
BACT	95.0	98.40	12.0	27.84
Most Stringent Technology	98.0	378.30	50.6	111.50
MIS and Lurgi (63,000)				
BACT	99.8	6.86	0.97	2.08
Direct Heat (55,000)				
BACT	96.4	22.80	3.23	7.08
Most Stringent Technology	98.0	26.54	19.38	23.87

* Costs are taken from EPA control cost estimates for the TOSCO, Paraho, and Rio Blanco processes and from the Union and Cathedral Bluff (MIS) PSD permit applications.

Exhibit B-4

CAPITAL RECOVERY FACTORS*

Process Category	CRF
External Indirect Heat	16.4% (average)
Internal Indirect Heat	16.4%
MIS	16.13%
MIS and Lurgi	16.23%
Direct Heat	16.9%

SOURCE: EPA Internal Documents.

Exhibit B-5

POLLUTION CONTROL COST SCALING METHODOLOGY

$$Y_2 = Y_1\left(\frac{X_2}{X_1}\right)^b$$

where:

Y_1 = Cost of facility 1 (known)*

Y_2 = Cost of facility 2 (unknown)

X_1 = Size of facility 1 (known)

X_2 = Size of facility 2 (known)

b = 0.8**

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* Operating and/or annualized capital costs.

** EPA engineers in Cincinnati suggest that since oil shale facilities are often built in modules, an appropriate scale factor for pollution control capital costs is 0.8.

The scaling factor for operating costs is 0.6.

This appendix illustrates the methodology that was used to calculate the SO_2 control costs for the existing Hayden utility plant and the Craig plant, which has three units. These costs are used to establish the cost of purchasing offsets which would allow for the siting of the proposed oil shale facilities. PHB has not estimated control costs for the Moonlake plant. This utility has agreed to install scrubbing units at 94 percent removal efficiency. PEDCo's cost model is not accurate for calculating costs at this percent removal. Because of this, and because the plant could not install any further So_2 control technology, the costs for this plant have not been estimated.* The control costs for the Hayden and Craig plant are important for the analysis.

To calculate the costs of SO_2 control for the Hayden and Craig electric generating plants, PHB relied on two cost models. One model, developed by PEDCo Environmental, Inc. was used to estimate costs for wet scrubbing systems.** Another model developed in a National Commission on Air Quality (NCAQ) report was used to estimate dry scrubbing costs. Craig units 1 and 2 have

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* Moonlake's control costs will be obtained from its PSD permit.

** <u>Simplified Procedures for Estimating Flue Gas Desulfurization System Costs</u>, PEDCo Environmental, EPA-600/2-76-150.

wet scrubbing units installed, while unit 3 will be equipped with a dry scrubber. It is assumed that the Hayden plant, if it were to retrofit control, would install a wet scrubbing system.

DESCRIPTION OF SO_2 CONTROL COST MODELS

PEDCo Model

The PEDCo model breaks capital costs into costs for lime preparation, SO_2 scrubbing, sludge disposal, and miscellaneous indirect costs. Annual costs include raw materials, labor, maintenance, overhead, fixed costs and trucking.* To run this model a number of inputs are required.

Exhibit C-1 lists the inputs that were assumed for each plant. The cost figures for labor, electricity and lime were taken from a recent PEDCo publication, while the capacity factors and distance to disposal sites were estimated using permit information from various utilities.

Besides these constant parameters, four plant-specific inputs are needed. These factors include the tons of SO_2 that must be removed per hour, the number of scrubber trains at the facility, and the plant's duct factor and flue-gas rate. To determine the tons of sulfur removed per hour, the quantity and type of coal for each plant need to be determined, and emissions for each alternative emission limitation should be calculated. The cost calculations follow procedures outlined in PHB's North Dakota case study.**

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* Fixed costs include taxes, insurance, and interim replacement.

** Putnam, Hayes & Bartlett, Inc., Evaluation of Alternative Prevention of Significant Deterioration Policies: A Case Study of Energy Development in Western North Dakota, Draft Report, October 1981.

Exhibit C-1

CONSTANT INPUTS

Input	Value	Source
Labor Cost	$15/hour	PEDCo Environmental
Electricity Cost	23.19 mill/kwh	PEDCo Environmental
Lime Cost	$40/ton	PEDCo Environmental
Capacity Factor (new plants)	70%	Estimate
Capacity Factor (existing plants)	60%	Estimate
Distance to Disposal Sites	3 miles	Permits

Dry Scrubbing Costs

Dry scrubbing is a relatively new technology and there are only a few plants which have operational dry scrubbers. Therefore, unlike the PEDCo model, dry scrubbing costs must be estimated using more generic cost equation formulas. The recent NCAW Four Corners Report included dry scrubbing equations that were developed by H. F. Hesketh.* The equations take the following form:

Capital Cost

$$\text{Cost} = (1.69 \times 10^4)(\text{mw})^{.75}(\%\ \text{control})^{.66}$$

Annual Cost

$$\text{Cost} = (2.77 \times 10^3)(\text{mw})^{.75}(\%\ \text{control})^{.66}$$

mw = design capacity
% control = percent of SO_2 control

These equations are used to estimate the dry scrubbing costs for unit 3 of the Craig facility.

Hayden SO_2 Control Costs

The Hayden plant currently has no SO_2 control. Therefore additional control would need to be retrofitted onto this plant. To estimate the costs for retrofitting pollution controls PHB reviewed the conclusions of several groups.** Based on this review, it has been decided that

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* H. F. Heskith, Economic Process Technology, and Cost Curve Development Data and Procedures for Coal-Fired Electrical Generation Facilities, 1979.

** ICF, Inc. Interim Results of Acid Rain Mitigation Study, January 15, 1981; PEDCo Environmental, Simplified Procedures for Estimating Flue Gas Desulfurization System Costs, EPA-600/2-76-150; Energy and Environmental Analysis, Inc., Conversation with Carl Held regarding EPA-generated cost curves.

an appropriate retrofit factor would be 1.3; that is, retrofitting control equipment costs 30 percent more than installing the same equipment on a new plant.

SO_2 control costs for Hayden were estimated at several different control levels. In general, wet scrubbing systems can be sized at any desired efficiency. PHB chose to estimate costs at 30 and 60 percent efficiency. Exhibit C-2 illustrates the plant-specific inputs that were used in the PEDCo model. When the plant-specific data are entered into the PEDCo cost methodology the following capital and annual costs are determined:

SO_2 CONTROL COSTS FOR HAYDEN
(mm 1985$)

	Hayden (30%)	Hayden (60%)
Capital Cost*	22.5	35.0
Annual Cost	3.8	7.8

Craig Units 1 and 2 and SO_2 Control Costs

The Craig units 1 and 2 were proposed to achieve a 75 percent SO_2 removal rate using wet scrubbing. Control costs were estimated at this proposed control level as well as a more stringent 85 percent control. Exhibit C-3 lists the plant-specific inputs that were used for these units.

Inputting the plant-specific data into the wet scrubbing model results in the following capital and annual costs for SO_2 control at Craig units 1 and 2.

* The 1.3 retrofit factor has been applied to the capital costs.

Exhibit C-2

PLANT-SPECIFIC DATA FOR HAYDEN

	Hayden (30%)	Hayden (60%)
Model Inputs		
SO_2 Tons/Hour Removed	1.8	3.6
Scrubber Trains	3	4
Duct Factor	0.48*	0.96
Flue Rate (000 cfm)	672**	1344
General Data		
Coal Use (000 T/Y)	1692+	1692
Percent Sulfur in Coal	0.912+	0.912
Avg. BTU/lb	10716+	10716
SO_2 Emission Control (#/mmBtu)	1.2	0.6

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* Based on PEDCo engineering formula.

** Flue-gas rate taken from Colorado Department of Health emission inventory.

\+ DOE, Cost and Quality of Fuels for Electric Utility Plants - 1979.

Exhibit C-3

PLANT-SPECIFIC DATA FOR CRAIG UNITS 1 AND 2

	Craig (75%)	Craig (85%)
Model Inputs		
SO_2 Tons/Hour Removed	2.9	3.30
Scrubber Trains	8	10
Duct Factor	1.33*	1.49
Flue Rate (000 cfm)	1598**	1811
General Data		
Coal Use (000 T/Y)	2449	2449
Percent Sulfur in Coal	0.49+	0.49
Aug. BTU/lb	10500+	10500
SO_2 Emission Control (#/mmBtu)	0.23	0.14

* Based on engineering formula.

** PSD permit information.

\+ DOE, Cost and Quality of Fuels for Electric Utility Plants - 1979.

SO_2 CONTROL COSTS AT CRAIG UNITS 1 AND 2
(mm 1985$)

	Craig (75%)	Craig (85%)
Capital Cost*	74.4	84.2
Annual Cost	16.8	19.4

Craig Unit 3 SO_2 Control Costs

The Craig plant's unit 3 will have a dry scrubbing system at an 88 percent removal efficiency. At this time, this is the maximum SO_2 control removal for a dry scrubbing system. Inputting this control efficiency along with this unit's designed capacity (447 mw) into the dry scrubbing cost equations results in capital and annual cost estimates of $31.5 and 5.2 million, respectively.

ANNUALIZED COSTS

PHB has annualized the capital costs of the scrubbing systems using a cash-flow model. To use this model a number of assumptions have to be made. Exhibit C-4 lists the inputs to the model and the values that were assigned to these inputs. Most of the rates used (e.g., income tax, inflation) are based on reasonable assumptions about the future, while the capitalization and depreciation figures used are common to most utilities. The cash-flow model, using the parameters listed in Exhibit C-4, generates a before-tax capital recovery factor (real dollars) of 8.38 percent. This factor has been used to annualize all of the utility capital cost figures in this report.

Exhibit C-5 summarizes the capital, annual and annualized costs for the Hayden and Craig utility plants. The annualized costs range from $5.7 million at Hayden with a 30 percent control level to $26.5 million at Craig units 1 and 2 at an 85 percent control level.

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* No retrofit factor is applied because construction is not completed at this plant.

Exhibit C-4

CAPITAL RECOVERY FACTOR
DATA INPUTS

Input	Value
Investment Tax Credit	10.0%
Inflation Rate	7.0%
Interest Rate	10.0%
Rate on Preferred	15.0%
Discount Rate	14.5%
Capitalization	
- Equity	40.0%
- Debt	60.0%
Useful Life of Pollution Control Equipment	15 years
Depreciable Life	5 years
Depreciation Method	Straight Line

Exhibit C-5

COSTS OF SO_2 CONTROL AT HAYDEN AND CRAIG
(mm 1985$)

Plant	Capital	Annual	Annualized
Hayden (30%)	22.5	3.8	5.7
Hayden (60%)	35.0	7.8	10.7
Craig 1 and 2 (75%)	74.4	16.8	23.0
Craig 1 and 2 (85%)	84.2	19.4	26.5
Craig 3 (88%)	31.5	5.2	7.8

AIR QUALITY IMPACTS OF EMISSION SOURCES AT BACT CONTROL — APPENDIX D

This appendix summarizes the cumulative air quality impact of the Moonlake and Craig utility plants and the oil shale facilities on the mandatory and proposed Class I areas. The figures represent the air quality impact of each source when an assumed BACT control level is required. This control level is needed to obtain a PSD permit.

The exhibits in this appendix include the cumulative air quality impact of each basin or combination of basins on the Class I areas. The values that are circled represent sources that would not be able to receive a permit because the increment ceiling would be violated. Each table represents the impact of sources on an individual Class I area.

Exhibit D-1

AIR QUALITY IMPACT AT MAROON BELLS
WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Uinta/Parachute
Moonlake 1 & 2			0.5	0.5
Union	0.4			
Colony	0.7			
TOSCO			0.6	1.6
Occidental		0.7		1.3
Geokinetics			0.6	1.3
Multimineral		1.0		1.6
White River			0.7	1.7
Superior		1.8		2.5
Pacific	1.3			
Paraho			1.0	2.8
Magic Circle			1.1	2.9
Rio Blanco		2.5		3.6
Exxon		2.8		3.9
Chevron	2.2			
Mobil	2.6			
Syntana			1.3	4.1
NOSR	3.9			
Cities Service	5.9			

Circled values indicate violations of the increment.

Exhibit D-2

AIR QUALITY IMPACT AT DINOSAUR PARK
WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Parachute/Piceance
Moonlake 1 & 2			2.9	
Union	0.4			0.4
Colony	0.6			0.6
TOSCO			3.3	
Occidental		1.3		1.9
Geokinetics			4.0	
Multimineral		1.9		2.5
White River			4.3	
Superior		3.7		4.3
Pacific	1.1			4.8
Paraho			5.8	
Magic Circle			6.2	
Rio Blanco		5.1		6.2
Exxon		5.9		7.0
Chevron	1.8			7.7
Mobil	2.2			8.2
Syntana			7.0	
NOSR	3.2			9.2
Cities Service	4.9			10.9

Circled values indicate violations of the increment.

Exhibit D-3

AIR QUALITY IMPACT AT COLORADO MONUMENT
WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta
Moonlake 1 & 2			1.4
Union	0.6		
Colony	0.9		
TOSCO			1.6
Occidental		1.0	
Geokinetics			1.9
Multimineral		1.4	
White River			2.0
Superior		2.6	
Pacific	1.7		
Paraho			2.8
Magic Circle			3.0
Rio Blanco		3.7	
Exxon		4.2	
Chevron	2.8		
Mobil	3.4		
Syntana			3.4
NOSR	4.9		
Cities Service	7.6		

Circled values indicate violations of the increment.

Exhibit D-4

AIR QUALITY IMPACT AT MT. ZIRKEL WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Uinta/Craig
Moonlake 1 & 2			0.4	0.4
Craig 1 - 3				5.0
Union	0.1			
Colony	0.2			
TOSCO			0.5	5.1
Occidental		0.7		
Geokinetics			0.5	5.1
Multimineral		0.9		
White River			0.6	5.2
Superior		1.5		
Pacific	0.4			
Paraho			0.9	5.5
Magic Circle			1.0	5.6
Rio Blanco		1.9		
Exxon		2.2		
Chevron	0.7			
Mobil	0.8			
Syntana			1.1	5.7
NOSR	1.3			
Cities Service	2.0			

Circled values indicate violations of the increment.

Exhibit D-5

AIR QUALITY IMPACT AT ROCKY MOUNTAIN
WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Uinta/Piceance
Moonlake 1 & 2			0.3	0.3
Union	0.1			
Colony	0.2			
TOSCO			0.3	0.3
Occidental		0.3		0.6
Geokinetics			0.3	0.6
Multimineral		0.4		0.7
White River			0.3	0.7
Superior		0.8		1.1
Pacific	0.4			
Paraho			0.6	1.4
Magic Circle			0.7	1.5
Rio Blanco		1.2		1.9
Exxon		1.4		2.1
Chevron	0.6			
Mobil	0.7			
Syntana			0.8	2.2
NOSR	1.0			
Cities Service	1.7			

Exhibit D-6

AIR QUALITY IMPACT AT RAWAH WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Uinta/Craig
Moonlake 1 & 2			0.3	0.3
Craig 1 - 3				1.7
Union	0.1			
Colony	0.2			
TOSCO			0.3	1.7
Occidental	0.3			
Geokinetics			0.3	1.7
Multimineral		0.4		
White River			0.3	1.7
Superior		0.7		
Pacific	0.3			
Paraho			0.6	2.0
Magic Circle			0.7	2.1
Rio Blanco		1.1		
Exxon		1.3		
Chevron	0.5			
Mobil	0.6			
Syntana			0.8	2.2
NOSR	0.9			
Cities Service	1.2			

Exhibit D-7

AIR QUALITY IMPACT AT EAGLE'S NEST
WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Parachute/Uinta
Moonlake 1 & 2			0.4	0.4
Union	0.2			0.6
Colony	0.3			0.7
TOSCO			0.5	0.8
Occidental		0.3		
Geokinetics			0.5	0.8
Multimineral		0.4		
White River			0.6	0.9
Superior		1.0		
Pacific	0.6			1.2
Paraho			0.9	1.5
Magic Circle			1.0	1.6
Rio Blanco		1.4		
Exxon		1.7		
Chevron	1.0			2.0
Mobil	1.2			2.2
Syntana			1.1	2.3
NOSR	1.7			2.8
Cities Service	2.7			3.8

Exhibit D-8

AIR QUALITY IMPACT AT ARCHES
WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Piceance/Craig
Moonlake 1 & 2			1.1	
Craig 1 - 3				0.6
Union	0.2			
Colony	0.3			
TOSCO			1.3	
Occidental		0.3		0.9
Geokinetics			1.6	
Multimineral		0.4		1.0
White River			1.7	
Superior		0.9		1.5
Pacific	0.6			
Paraho			2.2	
Magic Circle			2.3	
Rio Blanco		1.3		1.9
Exxon		1.5		2.1
Chevron	1.0			
Mobil	1.2			
Syntana			2.6	
NOSR	1.7			
Cities Service	2.7			

Exhibit D-9

AIR QUALITY IMPACT AT BLACK CANYON WITH BACT ASSUMPTIONS

Source	Parachute	Piceance	Uinta
Moonlake 1 & 2			0.6
Union	0.4		
Colony	0.6		
TOSCO			0.7
Occidental		0.7	
Geokinetics			0.7
Multimineral		0.9	
White River			0.8
Superior		1.6	
Pacific	1.1		
Paraho			1.1
Magic Circle			1.2
Rio Blanco		2.0	
Exxon		2.3	
Chevron	1.8		
Mobil	2.2		
Syntana			1.4
NOSR	3.2		
Cities Service	4.9		

AIR QUALITY IMPACTS OF EMISSION SOURCES AT MOST STRINGENT TECHNOLOGY LEVEL — APPENDIX E

This appendix summarizes the cumulative air quality impact of the Moonlake and Craig utility plants and the oil shale facilities on the mandatory and potential Class I areas. The figures represent the air quality impact of each source when most stringent technology is required.

The exhibits in this appendix include the cumulative air quality impact of each basin or combination of basins on the Class I areas. The values that are circled represent sources that would not be able to receive a permit because the increment ceiling would be violated. Each table represents the impact of sources on an individual Class I area.

Exhibit E-1

AIR QUALITY IMPACT AT MAROON BELLS
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Unita/Parachute
Moonlake 1 & 2			0.5	0.5
Union	0.4			0.9
Colony	0.7			1.2
TOSCO			0.5	1.2
Occidental		0.1		
Geokinetics			0.5	1.2
Multimineral		0.4		
White River			0.6	1.3
Superior		1.2		
Pacific	0.9			1.5
Paraho			0.8	1.7
Magic Circle			0.9	1.8
Rio Blanco		1.9		
Exxon		2.0		
Chevron	1.8			2.7
Mobil	2.2			3.1
Syntana			1.0	3.2
NOSR	3.3			4.3
Cities Service	4.1			5.1

Circled values indicate violations of the increment.

Exhibit E-2

AIR QUALITY IMPACT AT DINOSAUR PARK
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Parachute/Piceance
Moonlake 1 & 2			2.9	
Union	0.4			0.4
Colony	0.5			0.5
TOSCO			3.0	
Occidental		0.6		1.1
Geokinetics			3.3	
Multimineral		1.2		1.7
White River			3.6	
Superior		3.0		3.5
Pacific	1.0			4.0
Paraho			4.8	
Magic Circle			5.2	
Rio Blanco		4.4		5.4
Exxon		4.7		5.7
Chevron	1.7			6.4
Mobil	2.1			6.8
Syntana			5.5	
NOSR	2.9			7.6
Cities Service	3.6			8.4

Circled values indicate violations of the increment.

Exhibit E-3

AIR QUALITY IMPACT AT COLORADO MONUMENT WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta
Moonlake 1 & 2			1.4
Union	0.6		
Colony	0.9		
TOSCO			1.5
Occidental		0.4	
Geokinetics			1.6
Multimineral		0.8	
White River			1.7
Superior		2.0	
Pacific	1.7		
Paraho			2.3
Magic Circle			2.5
Rio Blanco		3.1	
Exxon		3.3	
Chevron	2.8		
Mobil	3.4		
Syntana			2.6
NOSR	4.6		
Cities Service	5.7		

Circled values indicate violations of the increment.

Exhibit E-4

AIR QUALITY IMPACT AT MOUNT ZIRKEL
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Unita/Craig
Moonlake 1 & 2			0.4	0.4
Craig 1 - 3				5.0
Union	0.1			
Colony	0.2			
TOSCO			0.5	5.1
Occidental		0.3		
Geokinetics			0.5	5.1
Multimineral		0.5		
White River			0.6	5.2
Superior		1.1		
Pacific	0.4			
Paraho			0.8	5.4
Magic Circle			0.9	5.5
Rio Blanco		1.5		
Exxon		1.6		
Chevron	0.7			
Mobil	0.8			
Syntana			0.9	5.5
NOSR	1.2			
Cities Service	1.5			

Circled values equal violations of the increment.

Exhibit E-5

AIR QUALITY IMPACT AT ROCKY MOUNTAIN WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Unita/Piceance
Moonlake 1 & 2			0.3	0.3
Union	0.1			
Colony	0.2			
TOSCO			0.3	0.3
Occidental		0.1		0.4
Geokinetics			0.3	0.4
Multimineral		0.2		0.5
White River			0.3	0.5
Superior		0.6		0.9
Pacific	0.4			
Paraho			0.5	1.1
Magic Circle			0.6	1.2
Rio Blanco		1.0		1.6
Exxon		1.1		1.7
Chevron	0.6			
Mobil	0.7			
Syntana			0.6	
NOSR	0.9			
Cities Service	1.2			

Exhibit E-6

AIR QUALITY IMPACT AT RAWAH
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Unita/Craig
Moonlake 1 & 2			0.3	0.3
Craig 1 - 3				1.7
Union	0.1			
Colony	0.2			
TOSCO			0.3	1.7
Occidental		0.1		
Geokinetics			0.3	1.7
Multimineral		0.2		
White River			0.3	1.7
Superior		0.5		
Pacific	0.3			
Paraho			0.5	1.9
Magic Circle			0.6	2.0
Rio Blanco		0.9		
Exxon		1.0		
Chevron	0.5			
Mobil	0.6			
Syntana			0.6	2.0
NOSR	0.8			
Cities Service	0.9			

Exhibit E-7

AIR QUALITY IMPACT AT EAGLE'S NEST
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Unita/Parachute
Moonlake 1 & 2			0.4	0.4
Union	0.2			0.6
Colony	0.3			0.7
TOSCO			0.4	0.7
Occidental		0.1		
Geokinetics			0.4	0.7
Multimineral	0.2			
White River			0.5	0.8
Superior		0.8		
Pacific	0.6			1.1
Paraho			0.7	1.3
Magic Circle			0.8	1.4
Rio Blanco		1.2		
Exxon		1.3		
Chevron	1.0			1.8
Mobil	1.2			2.0
Syntana			0.8	2.0
NOSR	1.6			2.4
Cities Service	2.0			2.8

Exhibit E-8

AIR QUALITY IMPACT AT ARCHES
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Piceance	Uinta	Piceance/Craig
Moonlake 1 & 2			1.1	
Craig 1 - 3				1.7
Union	0.2			
Colony	0.3			
TOSCO			1.2	1.8
Occidental		0.1		
Geokinetics			1.3	1.9
Multimineral		0.2		
White River			1.4	2.0
Superior		0.7		
Pacific	0.6			
Paraho			1.8	2.4
Magic Circle			1.9	2.5
Rio Blanco		1.1		
Exxon		1.2		
Chevron	1.0			
Mobil	1.2			
Syntana			2.0	2.6
NOSR	1.6			
Cities Service	2.0			

Exhibit E-9

AIR QUALITY IMPACT AT BLACK CANYON
WITH MOST STRINGENT TECHNOLOGY ASSUMPTIONS

Source	Parachute	Picaence	Uinta
Moonlake 1 & 2			0.6
Union	0.4		
Colony	0.6		
TOSCO			0.6
Occidental		0.3	
Geokinetics			0.6
Multimineral		0.5	
White River			0.7
Superior		1.2	
Pacific	1.1		
Paraho			0.9
Magic Circle			1.0
Rio Blanco		1.6	
Exxon		1.7	
Chevron	1.8		
Mobil	2.2		
Syntana			1.1
NOSR	3.0		
Cities Service	3.7		