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PROCEDURE FOR MATCHING SYNFUEL USERS WITH
POTENTIAL SUPPLIERS

Final Report

September 26, 1981

Work Performed Under Contract No. AC01-80RG10303

Resource Consulting Group, Inc.
Washington, D.C.

TECHNICAL INFORMATION CENTER
UNITED STATES DEPARTMENT OF ENERGY

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Procedure for Matching Synfuel
Users with Potential Suppliers:
Final Report

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CONTENTS

SECTION	TITLE	PAGE
INTRODUCTION		
SECTION 1	DEVELOPMENT OF SCREENS FOR IDENTIFYING SYNTHETIC FUELS SUPPLIERS	
	Technology Readiness	1.1
	Cost Competitiveness	1.2
	Project Completion Risk	1.3
	Fuel Availability	1.4
	Transportation Cost	1.4
	Supplier/User Compatibility	1.4
	Environmental Restrictions	1.5
SECTION 2	PROCEDURE FOR APPLYING THE SCREENS TO DIFFERENT TYPES OF SYNTHETIC FUELS PROJECTS	
	Low Btu Gas from Coal	2.1
	Medium Btu Gas from Coal	2.6
	High Btu Gas from Coal	2.10
	Liquid Fuels from Coal	2.14
	Liquid Fuels from Oil Shale	2.20
	Ethanol from Biomass	2.27
	Gaseous Fuels from Biomass	2.31

CONTENTS

SECTION	TITLE	PAGE
SECTION 3	MODIFICATION OF SCREENS TO EVALUATE THE FEASIBILITY OF ON-SITE DEVELOPMENT OF LOW AND MEDIUM BTU GASIFICATION	
	Low Btu Gas from Coal	3.2
	Medium Btu Gas from Coal	3.9
SECTION 4	APPLICATION OF SCREENS: THREE CASE STUDIES	
	Case #1: Hoffman-La Roche, Inc.	4.3
	Case Study #2: Tallahassee Electric Department	4.14
	Case Study #3: Houston Lighting and Power Company	4.22

APPENDIX A

Selected References

INTRODUCTION

As part of an overall strategy to promote national energy self-sufficiency, Congress passed the Powerplant and Industrial Fuel Use Act (FUA) on November 9, 1978. The primary objective of FUA is to promote the use of coal and other alternative fuels in lieu of oil and natural gas in new and existing power plants and industrial boilers.

To accomplish this objective, FUA prohibits new electric power plants and major fuel-burning installations (MFBIs)* from using petroleum or natural gas as a primary energy source, unless specifically exempted by the Secretary of Energy. After 1990, a prohibition applies to the use of natural gas in existing power plants and MFBIs.

Among temporary and permanent exemptions from these prohibitions, the Secretary may grant a temporary exemption based upon future use of synthetic fuels (sections 211(b) and 311(b) of FUA). The responsibilities for establishing rules and procedures governing synthetic fuels exemptions and for granting or denying exemptions were delegated by the Secretary to the Office of Fuels Conversion (OFC) in the Economic Regulatory Administration (ERA) of the Department of Energy (DOE).

To perform these responsibilities effectively, OFC retained Resource Consulting Group, Inc. (RCG), to develop a system for identifying synfuel producers that could supply major fuel users who are prohibited from using oil or natural gas by FUA and who may be eligible for a synthetic fuels exemption. The objective of this system would be to match synfuel users with potential suppliers.

* Power plants and MFBIs that are affected by FUA include single boilers, gas turbines, combined cycle units, and internal combustion engines with fuel heat input rates of 100 million Btu per hour or greater; or combinations of these units with an aggregate input rate of 250 million Btu per hour or greater.

INTRODUCTION

Before developing this system, OFC and RCG delineated four requirements that it should meet. Specifically:

1. It should provide OFC with an efficient and effective method of evaluating petitioner requests for synfuels exemptions. For example, if a petitioner cites a source for synthetic fuels that is feasible according to the system, OFC can act swiftly on the application. On the other hand, if the petitioner cites a source with low feasibility according to the system, OFC may request additional evidence concerning its feasibility.
2. The system should provide OFC with a basis for recommending an alternative, lower cost source of synthetic fuels.
3. It should allow OFC to take an aggressive role in providing information to prospective users, including petitioners requesting other exemptions under FUA (e.g., cost, environmental, site limitation), who may not have considered a synfuels exemption. By informing users of feasible sources of synfuel supplies, OFC can encourage the demand for, and hence the production of, synthetic fuels.
4. It should permit OFC to coordinate with the Synthetic Fuels Corporation or with the DOE's ongoing funded projects and to identify joint efforts to promote the development and use of synthetic fuels.

To meet these objectives, RCG conducted the following steps. First, we identified seven screens, which when applied to existing and proposed synthetic fuels projects eliminate all but the most feasible suppliers of synthetic fuels to a specific user. These screens are:

- Technology readiness. Is the synfuel conversion technology ready for commercial application?
- Cost competitiveness. Is the cost per unit of synthetic fuel competitive with alternative fuels?
- Project completion risk. Is there significant risk that the project will not be completed as scheduled?
- Fuel availability. Will there be sufficient quantities of the synthetic fuel available for the user.
- Transportation cost. Can the synthetic fuel be economically transported to the user?

INTRODUCTION

- Supplier/user compatibility. Are suppliers and users compatible with respect to fuel type and load characteristics?
- Environmental restrictions. Do environmental regulations effectively prohibit burning the fuel at some locations?

Second, on the basis of our analysis of synthetic fuels markets and technologies, we ordered the screens hierarchically for each type of synthetic fuels projects. The projects to be evaluated by this screening procedure would be existing and proposed projects that are separate from the prospective user. We categorized these projects as follows:

- Low Btu gas from coal
- Medium Btu gas from coal
- High Btu gas from coal
- Liquid fuels from coal (including methanol, heavy coal liquids, syncrude, and refined products)
- Liquid fuels from oil shale (including shale oil, syncrude, and refined products)
- Ethanol from biomass
- Gaseous fuels from biomass.

For example, two screens (i.e., transportation cost and fuel availability) will eliminate most of the low and medium Btu gas projects. Fuel from these projects cannot be economically transported more than 2 miles for low Btu gas and 150 to 200 miles for medium Btu gas. Moreover, because they are usually built to supply a specific user, or set of users, low and medium Btu gas projects frequently do not have fuel available for another user. Thus, to secure a supply of low or medium Btu gas, a user generally must construct his own on-site, or nearby, gasifier.

The project completion risk and technology readiness screens will eliminate many oil shale, coal liquefaction, and high Btu coal gasification projects. The risk of cancellation or delay for these projects is high because of technology and cost uncertainties, potential financing problems, and the possibility of legal and regulatory delays.

The cost competitiveness screen will eliminate most ethanol projects. Ethanol will not be priced competitively with alternative boiler or turbine fuels because it can command a much higher price as a gasohol ingredient.

INTRODUCTION

Finally, the fuel availability and transportation cost screens will eliminate many projects for producing gas from biomass. All of the existing and proposed projects in this category are landfill methane projects with relatively low output. Because of the low production rate, the medium Btu gas produced from these projects cannot be economically transported more than 4 miles.

As the third step in the development of our screening procedure for matching prospective synthetic fuel users with synthetic fuel producers, we modified the screens and screening procedure to evaluate the feasibility of on-site development of low and medium Btu gas. The five screens developed for this evaluation are:

- Site selection and area requirements. Is the prospective user capable of receiving coal and is there sufficient land to construct a gasifier and appurtenant facilities?
- User compatibility. Can the user use low or medium Btu gas; is the rate and continuousness of fuel consumption sufficient to support economic operations; for existing facilities, will there be deratings and is there sufficient remaining facility life to amortize the gasification project?
- Environmental restrictions. Will environmental restrictions preclude construction and operation of a gasification facility?
- Access to feedstock and cost competitiveness. Can the prospective user obtain adequate coal and, considering shipment distance, at a cost that will permit competitive production of low or medium Btu gas?
- Project completion risk. Are there factors such as financial problems that might impede project completion?

Fourth, to illustrate application of the screening procedure, we performed case study analyses for three potential users of synthetic fuels:

- A Hoffman-LaRoche, Inc., facility
- The Purdon electric generating station of the Tallahassee Electric Department
- The Cedar Bayou generating station of the Houston Lighting and Power Co.

INTRODUCTION

For these prospective users of synthetic fuels, we applied the screens for matching the user with current or planned producers of synthetic fuel and for evaluating the feasibility of developing on-site low or medium Btu gasification. Application of the screening procedure resulted in the identification of one or more candidates for supplying synthetic fuel to each of the prospective users.

In the following chapters, we describe the development of the screening procedure. Chapter 1 contains a detailed description of the seven screens; Chapter 2 describes the development of the hierarchical procedure for applying the screens to each synthetic fuels project; Chapter 3 describes the modification of the screening procedure for low and medium Btu gas; Chapter 4 describes the application of the procedure. Appendix A is a list of references used in developing the procedure; Appendix B is a detailed listing of proposed and ongoing synthetic fuel projects.

1

DEVELOPMENT OF SCREENS FOR IDENTIFYING SYNTHETIC FUELS SUPPLIERS

On the basis of our analysis of synthetic fuels technologies and markets, we identified the economic, technological, and institutional factors that are most likely to determine whether a synthetic fuels project is a feasible supplier for a specific user. We determined that there were seven primary factors or screens that could be used to match synthetic fuel users with suppliers:

1. Technology readiness
2. Cost competitiveness
3. Project completion risk
4. Fuel availability
5. Transportation cost
6. Supplier/user compatibility
7. Environmental restrictions.

These screens are described in detail below.

TECHNOLOGY READINESS

The developmental process for converting coal, oil shale, or biomass to synthetic fuels consists of six stages:

1. Initial concept--occurs at the beginning of the development process, prior to any physical testing
2. Bench-scale experiments (up to 6 gallons of output per day)--involves scientific proof of concept and typically occurs 1 to 4 years into the developmental process
3. Process development (3 to 9 barrels of output per day)--involves further development of basic technology and typically occurs 4 to 6 years into the developmental process

4. Pilot plant (75 to 1800 barrels per day)--involves engineering confirmation and feasibility of the technology and typically occurs 5 to 8 years into the developmental process

5. Demonstration or pioneer plant (5,000 to 50,000 barrels per day)--involves integrated and economic operation of the technology and may occur 8 to 12 years into the developmental process

6. Commercial facilities (over 50,000 barrels per day)--involves full-scale plants producing fuels at competitive fuel volumes and prices and typically occurs more than 12 years into the developmental process.

In our judgment, proposed projects using a technology that has not been tested to confirm engineering feasibility (i.e., fully tested at the pilot plant stage) are too risky to be considered suppliers under the terms of the synthetic fuels exemption. Projects in this category include, for example, those using in-situ coal gasification and shale oil extraction.

COST COMPETITIVENESS

Generally, a user will choose to apply for a synthetic fuel exemption and later burn the synthetic fuel, if it is the lowest present value cost option for meeting the end-use requirements. Available fuel options may include oil or natural gas (if a permanent exemption from FUA can be obtained), coal, synthetic fuels, and other "alternative fuels," such as refuse-derived fuels, geothermal, and wood. Unless the user places a high diversification value on the use of synthetic fuels, he will not choose the synthetic fuels option if its cost exceeds the cost test rule established by OFC for a permanent exemption from FUA. Moreover, even if the cost is below the cost test ceiling, the prospective user will not choose a synthetic fuel, if he can burn coal at a lower cost.

The cost test rule (10 CFR parts 503 and 504) allows a user to burn oil or natural gas if the lowest cost alternative fuel (per barrel of fuel oil equivalent) exceeds by more than \$1.00 the prevailing market price of fuel oil.* On the basis of this criterion, a project would not be considered a feasible supplier of synthetic fuel, if the

* The \$1.00 per barrel is the "substantially exceeds premium" used in the cost test calculation.

delivered price of that fuel (per barrel fuel oil equivalent) significantly exceeds a threshold price equal to the price of fuel oil plus \$1.00. As of May 1981, this threshold is between \$7 and \$8 per million Btu.

PROJECT COMPLETION RISK

Project completion risk is an important consideration in matching suppliers and users. If a synthetic fuel project is not completed, or if it is delayed significantly, the user must secure alternative fuel supplies. If the user holds a synthetic fuels exemption, he may be forced to continue burning oil or natural gas beyond the expiration date. Such a continuation is contrary to the basic purposes of FUA, may subject the user to significant civil penalties, and poses additional administrative burdens on OFC.

Judging project completion risk is not a simple matter because many unpredictable technological, economic, political, and legal factors can cause a project to be cancelled or postponed. However, there are several "rules of thumb" that OFC can use in applying project completion risk as a screening criteria.

- If the technology readiness of a project is found to be low when the first screen is applied, the project risk should be judged as being high. Specifically, if there has not been a successful pilot demonstration of the technology, the project risk may be unacceptably high.
- The project should be far enough along to provide reasonable assurance that it will be completed on schedule. For example, oil shale projects should be through the feasibility study, site selection, and environmental permit stage; otherwise, the risk of technological and environmental delays is excessive. In contrast, landfill gas projects may have acceptable completion risks once a feasibility study is completed.
- The project should be free of pending legal, regulatory, or other actions that could seriously jeopardize project completion. For example, some oil shale projects are in jeopardy owing to ongoing legal disputes over resource ownership.

* On the basis of a price of \$0.93 to \$1.04 per gallon of No. 2 distillate fuel oil, with a heat value of 5.8 million Btu per barrel (The Oil and Gas Journal, May 18, 1981).

FUEL AVAILABILITY

To be considered feasible, a project should be capable of supplying a significant portion of the user's fuel requirements. Although users seeking a synthetic fuels exemption could have more than one supplier, contracting with multiple suppliers entails transactions costs that are not present with a single supplier. Given these costs, we recommend that a project should be capable of supplying at least 50 percent of the user's fuel requirements.

TRANSPORTATION COST

The cost per unit of synthetic fuel may be competitive with alternative fuels if the supplier and user are in close proximity. However, it may not be competitive if the synthetic fuel must be transported further than some threshold distance. This distance will depend on the available modes of transportation and the opportunity for fuel swapping, both of which depend on the type of fuel. Low and medium Btu gas, for example, are much more expensive to transport than high Btu gas. The later can be transported through existing interstate gas pipelines, while synthetic gas produced in one location can be swapped for natural gas in the distribution system serving the user.

In general, transportation costs will be lowest for those synthetic fuels that are perfect substitutes for refined petroleum fuels (diesel and residual fuel oils) and natural gas because of the extensive, existing transportation infrastructure. Perfect synthetic substitutes include synthetic crude and refined products from coal and oil shale and synthetic natural gas. Other synthetic fuels, including low and medium Btu gas, ethanol from biomass, methanol from coal, and unrefined shale oil and coal liquids have a much more limited range of feasible distribution to potential users.

SUPPLIER/USER COMPATIBILITY

To be a feasible supplier to a specific user, the synthetic fuel characteristics and load requirements of the supplier and user must match.

The primary issue concerning fuel characteristics is whether the user can convert its facility at reasonable cost from oil to gas to the synthetic fuel by the end of the exemption period. The conversion cost will be a func-

tion of the chemical similarity between the conventional fuel and the synthetic fuel. For example, there is no cost associated with converting from natural gas to high Btu gas. When the conventional and synthetic fuels, however, have different corrosivity, different heat values, and/or combustion characteristics, conversion may be prohibitively expensive. Conversion of existing gas turbines to ethanol or methanol will be high, for example, if the turbine components are not resistant to the corrosivity of these fuels.

The feasibility of some supplier/user matches depends on the supplier and user having similar load requirements.

Specifically, the user may require a continuous, noninterruptible supply of fuel for economical operations. Similarly, the supplier may require a continuous demand that does not fluctuate significantly on a day-to-day, or hour-to-hour, basis. These load requirements can be expressed according to the load factor (the ratio of average to maximum rate of supply or demand during a given time interval) and the load profile (the systematic fluctuation of supply or demand over time). Synthetic fuels projects require a demand characterized by a high load factor and flat load profile if shutdown and start-up costs are high and if the fuel cannot be easily stored. This situation characterizes low and medium Btu gas projects. Users exhibiting high load factors and flat load profiles include baseload electric power plants and industrial boilers in the textile, paper, chemicals, petroleum, and primary metals industries. Users with low load factors and variable load profiles include peakload electric power plants and industrial boilers in the food and fabricated metals industries.

ENVIRONMENTAL RESTRICTIONS

The combustion of a synthetic fuel must conform to air quality regulations that exist at the end-use location. The type of pollutants present varies by synthetic fuels as does the cost of compliance. Therefore, OFC must consider three factors in applying this screen:

1. The type of pollutants present in the fuel
2. The stringency of air quality regulations at the end-use location
3. The cost and feasibility of complying with these regulations.

High and medium Btu gas, alcohol fuels, and refined products from synthetic crude will easily pass this screen because the fuels are at least as clean burning as the oil or natural gas that they will replace at the end of the synthetic fuels exemption. However, unrefined shale oil and coal liquids may face environmental restrictions as boiler fuels because of the presence of arsenic and carcinogens. Low Btu gas may also face restrictions in some areas because of its high nitrogen content (50 percent).

2 PROCEDURE FOR APPLYING THE SCREENS TO DIFFERENT TYPES OF SYNTHETIC FUELS PROJECTS

To facilitate the application of the seven screens to the nearly 200 existing or planned synthetic fuels projects, we ordered the screens hierarchically for each type of synthetic fuels project:

- Low Btu gas from coal
- Medium Btu gas from coal
- High Btu gas from coal
- Liquid fuels from coal
- Liquid fuels from oil shale
- Ethanol from biomass
- Gaseous fuels from biomass.

The first screen tends to eliminate the greatest percentage of suppliers for a given user; the second screen eliminates the greatest percentage of suppliers that pass the first screen; the third screen eliminates the greatest percentage of suppliers that pass the first two screens; and so on, until only the feasible suppliers remain. By following this hierarchy, the users of the system can minimize the number of analytical steps required to identify feasible suppliers.

In the following sections, we describe this hierarchical ordering according to the type of synthetic fuel project.

LOW BTU GAS FROM COAL

Low Btu gas from coal (LBG) is produced through a chemical reaction of coal, steam, and air. Coal is first crushed and either dried or mixed with water to form a slurry, depending on the process. The prepared coal is then fed into the gasification chamber, where it reacts with steam and air at high temperatures (ranging from 1500 to 3500°F)

and usually at high pressure (up to 1600 pounds per square inch). The resulting gas has a heat content of 125-175 Btu per standard cubic foot (scf), compared to 1000 Btu per scf for natural gas.

Technically, LBG can be used for any of the applications covered by FUA. Its primary uses are as a boiler fuel for new and existing utility or industrial boilers and as a gas turbine fuel for combined cycle electric power generation.

In matching LBG suppliers with a specific user, OFC should apply the seven screens in the following order:

1. Transportation cost
2. Fuel availability
3. Supplier/user compatibility
4. Project completion risk
5. Technology readiness
6. Cost competitiveness
7. Environmental restrictions.

We describe the application of these screens below.

Transportation Cost

The transportation cost screen is ranked first in the screening hierarchy for LBG projects. Most LBG projects will fail to pass this screen, because LBG can be transported economically for only 1 or 2 miles. There are two reasons for this constraint:

1. LBG is produced at low pressure; therefore, it must be compressed before being transported through a pipeline.
2. LBG cannot be transported through existing natural gas pipelines because of its high nitrogen content.

Even if these problems were overcome and the gas could be transported through existing pipelines, the transportation cost per Btu for LBG would still be seven times that of natural gas, or 20¢ to 36¢ per Btu, per 100 miles. In essence, then, LBG must be generated and used at the same site.

We recommend that a project pass this screen only under two conditions:

- The user is planning to construct its own on-site gasifier
- The user is negotiating with a second party to construct and operate the gasifier.

Fuel Availability

The fuel availability screen ranks second in the screening hierarchy for LBG projects. Most LBG projects will not pass this screen because LBG plants are designed and built to supply a single on-site use (e.g., electric power generation). Therefore, except in those instances where an LBG facility is planned to supply an entire industrial park, fuel will not be available to supply any users other than one for which the plant was originally designed. Because of the on-site, single-user characteristics, LBG projects are generally not feasible suppliers for firms seeking synthetic fuels exemptions. There are two exemptions to the "rule":

1. A firm may request a synthetic fuel exemption to burn oil or natural gas while the on-site gasifier is being built.
2. OFC may be able to match a user with an LBG project at an industrial park facility. This possibility is remote, however, because, before progressing beyond the feasibility study, the LBG project will have lined up sufficient customers. Once the project has been planned, it is unlikely that there will be sufficient excess fuel to meet the needs of a large user seeking a synthetic fuels exemption.

Supplier/User Compatibility

Supplier/user compatibility is the third ranking screen for LBG projects. Low Btu projects tend to be small (i.e., 1 to 3 billion Btu/day) with the output dedicated to a single end-user. Because of their relatively high capital to operating cost ratio (50 to 60 percent) and the cost of constructing storage facilities, LBG projects must have a high load factor (i.e., above 0.70) to be economically viable. As a result, LBG is a poor fuel choice for peak or intermediate load gas turbines, but it is a feasible choice for combined cycle or steam

boiler applications that require relatively constant day-to-day input. However, because LBG has a lower heating value and lower flame temperature than natural gas, LBG and natural gas cannot be burned in the same equipment without modifications. Because these modifications impose additional costs, most users will try to have the gasifier on-line when the end-use facility is built, which obviates the need for a synthetic fuels exemption.

Project Completion Risk

Project completion risk is the fourth ranking screen for LBG projects. Project completion risk is very specific to the individual LBG project. Because the technology has been used commercially and because environmental problems are not severe, the project completion risk should be considered acceptable if an economic and technical feasibility study of the project has been completed and if project financing is secure. Furthermore, because LBG projects are generally small and use a variety of coals, they are less likely to be jeopardized by legal or administrative delays than large oil shale or coal conversion projects.

Technology Readiness

This screen ranks fifth in the screening hierarchy for LBG projects because low Btu coal gasification is generally at a high level of technology readiness. Currently, over 40 coal gasifiers are in various stages of commercial development. These gasifiers can be classified according to the method by which the coal is brought in contact with steam and air. In fixed bed gasifiers, coal is fed on to a grate (which may be stationary or moving), and the steam and air pass upward through the coal. The fluidized bed gasifier is similar except that the velocity of the steam and air are such that the coal particles become suspended in the upward flowing gas stream. In entrained flow gasifiers, pulverized coal is injected into a high velocity flow of steam and air.

Currently, there are 14 gasifiers (mostly of the fixed bed type) available commercially; 12 of these have been successfully operated at commercial levels. Five other gasifiers have had successful pilot tests. We list these 19 coal gasifiers on the following page.

Fixed bed gasifier

Lurgi	Commercial
Wellman-Galusha	Commercial
Wilputte	Commercial
Riley Morgan	Commercial
Davy-Powergas	Commercial
Wellman-Incandescent	Commercial
Stoic-Foster Wheeler	Commercial
Pullman-Sevindell/IFE	Commercial
Woodall-Duckman/GI	Commercial
Koppers/Kerpely	Commercial
Slagging Lurgi	Demonstration

Fluidized bed gasifiers

Winkler	Commercial
Cogas	Pilot
IGT-UG	Demonstration
Synthane	Pilot

Entrained flow gasifiers

Koppers-Totzek	Commercial
Texaco	Demonstration
Combustion-Engineering	Demonstration
Bigas	Pilot

Projects employing gasifiers that are entering the pilot plant phase (Hydrane, Kilngas, TOSCOAL) may pass the technology readiness screen in the near future.

Cost Competitiveness

The cost competitiveness screen ranks sixth in the screening hierarchy for LBG projects. For on-site applications, LBG is cost competitive with oil and natural gas. The estimated cost per million Btu of LBG, at the gasification facility, is \$3.40 to \$7.80, depending on whether the gas is used raw or cleaned of oils, tars, and sulfur.* These costs compare favorably to decontrolled fuel oil and

* Cost estimates are in 1981 dollars. Source: Booz, Allen and Hamilton, Inc., 1979. Costs in 1979 dollars escalated using the consumer price index.

natural gas prices (currently \$4.80 to \$8.40 per million Btu)* and generally fall below the cost test cutoff of \$7.00 to \$8.00 per million Btu.

Environmental Restrictions

Environmental restrictions rank seventh in the screening hierarchy for LBG projects. Projects will be eliminated by this screen only if the user is located in certain nonattainment areas.

The contaminants in LBG that can cause problems are nitrogen (about 50 percent of the gas) and hydrogen sulfide (percent varies according to the sulfur content of coal burned). Because of these contaminants, the combustion of LBG emits nitrogen (NO_x) and sulfur dioxide (SO_2). Although these emissions are generally within the new source performance standards under the Clean Air Act,** the emissions may still be too high for class III nonattainment areas, with high ambient levels of NO_x or SO_2 , or for class I areas with pristine air quality.

MEDIUM BTU GAS FROM COAL

Medium Btu gas from coal (MBG) is produced through a process nearly identical to that for LBG. The primary difference is that oxygen, rather than air, is chemically reacted with coal and steam. After cleaning, the resulting gas is composed of mostly carbon monoxide, carbon dioxide, and hydrogen. Depending on the gasifier, MBG has a heating value of 250-350 Btu per scf, compared

* The lower figure (\$4.80) is for imported Mexican and Canadian natural gas. The upper figure (\$8.40) is for unregulated natural gas from a domestic well, as reported in The Oil and Gas Journal, May 18, 1981. Fuel oil prices are currently about midway between these prices (\$6.00 to \$7.00 per million Btu.)

** New source performance standards for SO_2 will be met, provided the coal feedstock is relatively low sulfur (less than 0.72 percent). The standards can be met for higher sulfur coal only through expensive gas desulfurization. For example, the cost of desulfurizing LBG will add about \$1-2 per million Btu to LBG's production cost.

with 1000 Btu per scf for natural gas. Medium Btu coal gas can be used in existing oil- or natural gas-fired utility boilers, new baseload generating units, baseload and intermediate load combined cycle gas turbine applications, industrial boilers, and as a gas turbine fuel for peak load power generation.

The order in which the screens are to be applied to MBG projects is as follows:

1. Transportation cost
2. Fuel availability
3. Project completion risk
4. Supplier/user compatibility
5. Technology readiness
6. Cost competitiveness
7. Environmental restrictions.

We describe their application below.

Transportation Cost

The transportation cost screen is ranked first in the screening hierarchy for MBG projects. Because of the difference in Btu value and other compositional differences, existing gas pipelines cannot be used for transporting MBG unless they are first evacuated of natural gas. Even then, natural gas pipelines may not be suitable because the high concentration of oxides (e.g., CO and CO₂) in MBG may lead to cracking in normal pipeline steels and accelerate corrosion. Because special pipelines must be constructed and the gas must be compressed, the maximum feasible distance for transporting MBG from supplier to user is directly related to the fuel requirements of the user; that is, the user must purchase enough fuel to justify the capital expense of a dedicated pipeline. Therefore, the user should be located within 150 to 200 miles of the MBG facility.

Fuel Availability

Fuel availability ranks second in the screening hierarchy for MBG projects. Although MBG facilities are more likely than LBG facilities to have nondedicated gas available for purchase, many MBG projects will fail to pass this

screen. MBG facilities tend to be larger (50 to 150 billion Btu per day) than LBG facilities (1 to 3 billion), and the gas can be economically transported over a greater distance (i.e., 150 to 200 miles compared to 1 to 2 miles). For these reasons, an MBG facility is much more likely to serve multiple users.

Accordingly, MBG projects are less likely to be designed or constructed in conjunction with an end-use facility. Moreover, because many MBG plants are larger, they can supply a wider range of end-users: from small industrial boilers to large (e.g., 300 megawatt) combined cycle generating plants. Although opportunities may exist for matching a user with an MBG supplier, in most cases, MBG projects will have lined up customers for their output prior to construction.

Project Completion Risk

Project completion risk is the third ranking screen for MBG projects. Project completion risk is generally acceptable if a detailed engineering and economic (for multiple-user facilities) feasibility study has been completed and gas sales contracts have been negotiated with some users. Owing to their larger size, MBG facilities may be slightly more vulnerable than LBG facilities to construction delays or to obtaining a favorable contract for the coal feedstock.

Supplier/User Compatibility

Supplier/user compatibility is the fourth ranking screen for MBG projects. Supplier/user compatibility for MBG is predicated on a number of factors:

1. If the MBG is to be dedicated to a single user, the user's fuel requirements must be at least 10 billion Btu per day. Lower output is generally not economic because of the relatively high cost of the plant that supplies oxygen to the gasifier.
2. Depending on the size of the MBG facility, the load factor of the user(s) is important to the economic viability of the project. Smaller MBG facilities (30 to 50 billion Btu per day) have high (60 to 70 percent) capital to operating cost ratios. The load factor for these plants must be high if the investment is to yield a reasonable rate of return. For large projects (120 to 140 billion Btu per day), the load factor can be lower (below 0.7), and the project will still be feasible.

Supplier/user compatibility, however, is not affected by the technical fit of the gas itself. The flame temperature, combustion, and flow volume characteristics are close to those for natural gas. Only slight modifications are required for MBG's use in existing boilers and generating equipment.

Technology Readiness

Technology readiness ranks fifth in the screening hierarchy for MBG projects. Twelve coal gasifiers capable of producing MBG are commercially available; two are commercially available but have not been demonstrated; five have been successfully tested at the pilot plant level but are not now commercially available. These 19 gasifiers (listed under low Btu gas from coal) are at a level of commercialization that meets our criteria for passing the technology readiness screen.

Cost Competitiveness

Cost competitiveness ranks sixth as a screen for MBG projects. Medium Btu can be cost competitive with oil and natural gas. The estimated cost to produce MBG is between \$3.70 and \$11.60 per million Btu, depending on plant scale, financing, and other factors.* Large (120 to 140 billion Btu per day) multiple-user MBG facilities can generally produce gas within the \$7 to \$8 per million Btu range. Smaller (30 to 50 billion Btu per day) facilities, however, have higher costs (\$5.40 to \$11.60 per million Btu). The cost of borrowed and equity capital, coal prices, plant load factor, and other plant-specific factors can affect whether these facilities pass the cost competitiveness screen.

Environmental Restrictions

Environmental restrictions impose no serious constraints on MBG use; therefore, they are ranked as the seventh screen. Because MBG contains little nitrogen, there is no nitrogen oxide emissions problem. Moreover, if high

* Source: Booz, Allen, and Hamilton, 1979. All costs have been escalated to 1981 dollars using the consumer price index.

sulfur coals are used or if the gasifier is in a nonattainment area for SO_2 , gas desulfurization units can be installed, at a cost of \$1-2 per million Btu, to meet air quality regulations.

HIGH BTU GAS FROM COAL

High-Btu gas from coal is produced from medium Btu gas, through a step known as "methanation." In the methanation step, carbon monoxide and hydrogen are combined in the presence of a catalyst to form methane. The resulting gas is a high Btu, pipeline quality, synthetic natural gas (SNG). Essentially identical to natural gas, SNG is composed mostly of methane, can be comingled and transported in existing pipelines, and has a high heat value (1000 Btu per scf). SNG can be used in any utility or industrial boiler, gas turbine, or combined cycle application.

The order in which the screens are to be applied to SNG projects is as follows:

1. Project completion risk
2. Technology readiness
3. Fuel availability
4. Transportation cost
5. Cost competitiveness
6. Supplier/user compatibility
7. Environmental restrictions.

We describe these below.

Project Completion Risk

Project completion risk is the highest ranked screen for SNG projects. The risk that an SNG project will be abandoned, or significantly delayed, is high, particularly during the preconstruction period. This risk arises from a number of factors. More specifically:

1. No commercial-scale SNG facilities have been built; therefore, delays may occur because of unanticipated technical problems.

2. SNG plants require a massive investment (i.e., \$1 to \$4 billion for a large facility). Because of the size of the investment and the commercially unproven nature of the technology, a significant risk exists that project sponsors will be unable to secure financing or that financing difficulties will delay the project.

3. The size of the SNG facilities can lead to legal disputes, which can delay the project. These disputes can arise over the acquisition and mining of the coal feedstock and over siting and other construction details of the project, particularly environmental controls.

Because of these risks, we recommend that a project pass the project completion risk screen only under the following conditions:

- All environmental permits and clearances have been obtained
- There are no outstanding or pending lawsuits that could jeopardize the project
- The project has a firm source of coal feedstock
- Firm commitments for project financing have been obtained.

Technology Readiness

Technology readiness is the second ranking screen for SNG projects. Only one high Btu coal gasification process, Lurgi/methanation, is at a high state of technology readiness. In the Lurgi/methanation process, a methanation step is added to the conventional Lurgi medium Btu gasifiers. The Lurgi process is particularly well adapted to methanation because of the favorable proportions of hydrogen and carbon monoxide in the medium Btu gas. This technology has been extensively tested abroad, and all the components are available commercially. Although the process has not been demonstrated on a full-scale commercial basis (i.e., greater than 15 billion Btu per day), the technical risks are acceptable. The Lurgi/methanation process is being proposed for most of the high Btu coal gasification projects currently being promoted, including the first planned commercial venture, the Great Plains Coal gasification project in North Dakota.

Other high Btu gasification processes have been tested at the pilot plant stage but have not been proven in a demonstration scale facility. These processes include Conoco/slugging Lurgi with methanation, Cogas, HYGAS, and Bigas. These processes, and other combinations of proven medium Btu gasifiers and methanation, are within reasonable limits of technological readiness.

Fuel Availability

Fuel availability ranks third in the screening hierarchy for SNG projects. In general, high Btu gasification projects will satisfy the fuel requirements of most energy users seeking a synthetic fuels exemption under FUA. Most of the active commercial projects will achieve peak SNG output of 130 to 300 billion Btu per day, enough to supply a 500-megawatt baseload generating facility. However, fuel availability may be affected if the project sponsors have negotiated contracts to sell all or part of the project's output.

Transportation Cost

Transportation cost ranks fourth as a screen for SNG projects. Transportation economics for SNG are quite favorable because the gas can be transported through existing natural gas pipelines. Unlike MBG or LBG, SNG projects are usually designed to serve the interstate natural gas market rather than nearby or on-site users. Moreover, because SNG is a direct substitute for natural gas, users can purchase SNG and then exchange it for natural gas available in the distribution system supplying the user.

Cost Competitiveness

Cost competitiveness is the fifth ranking screen for SNG projects. SNG from large gasification projects can probably be produced at a cost that is competitive with unregulated natural gas and fuel oil. A great deal of uncertainty exists concerning the cost of SNG because no commercial facility has been built. However, the various cost estimates available for large-scale Lurgi/methanation facilities indicate the process is a reasonably good economic risk. Cost estimates for SNG range from \$3.20 to \$8.20 per million Btu, compared to \$6 to \$8 per unregulated

gas and fuel oil.* In any event, once the project is completed, the SNG must compete with unregulated natural gas, which generally is priced within the \$7 to \$8 per million Btu ceiling for passing the cost test.

Supplier/User Compatibility

Supplier/user compatibility is the fifth ranking screen for SNG projects. Most SNG projects should easily pass the compatibility screen on both the fuel characteristics and load factor dimensions.

With regard to fuel characteristics, SNG is practically identical to natural gas; moreover, because SNG will be injected into natural gas pipelines, the user will probably be receiving natural gas or a natural gas/SNG mixture, rather than pure SNG. Thus, there are no economic or technical problems in switching from natural gas to SNG.

With regard to load factors, SNG will generally not be supplied directly to the user but will first enter the natural gas pipeline system and mix with the natural gas. Therefore, the load factor of the user or supplier is not an important consideration, because excess SNG over the specific user's current demand will be absorbed by the distribution system. Similarly, occasional reductions or shutdowns of SNG production will not affect a specific user because any shortfall between his current demand and SNG supply will be met by natural gas from the distribution system.

Environmental Restrictions

The environmental restrictions screen ranks last for SNG projects. SNG is a clean-burning substitute for natural gas. No environmental restrictions limit its use.

* Source: U.S. Senate, Committee on Energy and Natural Resources, January 1981. Costs escalated to 1981 using the consumer price index.

LIQUID FUELS FROM COAL

Liquid fuels from coal can be produced by several processes, which are usually classified as either indirect or direct.

Indirect coal liquefaction involves two steps: converting coal to medium Btu (synthesis) gas, then catalytically reacting the MBG to produce liquid fuels. The type of fuels produced depends largely on the type of catalyst used in the second step. In the Fischer-Tropsch process, the synthesis gas is reacted with an iron catalyst to produce a slate of products that includes gasoline, diesel fuel, fuel oil, and methanol. In the methanol synthesis process, the synthesis gas is reacted with a zinc or copper catalyst to form methanol.

Direct coal liquefaction involves chemically breaking down the coal while adding hydrogen, usually at high temperatures and high pressure. There are three basic processes for adding hydrogen (hydrogenation): pyrolysis (a thermochemical transformation), solvent extraction, or catalytic synthesis. Each of the processes is being extensively tested in a pilot plant. COGAS uses pyrolysis, SRC-II uses solvent extraction, H-Coal uses catalytic synthesis, and Exxon Donor Solvent (EDS) uses a combination of solvent extraction and catalytic synthesis.

The products of direct coal liquefaction include methanol, coal naptha, and heavy oils. The latter two products can be refined into a full slate of petroleum products, including gasoline, diesel fuel, and fuel oil. In addition, methanol can be converted to gasoline using Mobil's M-Gasoline process. The middle and heavy distillates from the liquefaction process can be used in place of conventional petroleum products to produce power generation and industrial process heat applications.

The screens for matching suppliers of liquid fuels from coal to users should be applied in the following order:

1. Project completion risk
2. Technology readiness
3. Fuel availability
4. Transportation cost
5. Cost competitiveness

6. Environmental restrictions
7. Supplier/user compatibility.

Their application is described below.

Project Completion Risk

Project completion risk is the highest ranked screen for coal liquefaction projects. The risk of a project being abandoned or significantly delayed is very high for coal liquefaction. Indeed, in our judgment, none of the planned coal liquefaction projects have acceptable project completion risks. This judgment stems from a number of considerations.

First, the cost of producing liquid fuels from coal is highly uncertain. Even the costs of the Fischer-Tropsch process are uncertain because of important differences in costs between operating in the United States and South Africa. Fluor, Inc., has estimated the capital investment cost of a Sasol-II facility in the United States at \$2.5 to \$3.6 billion (1979 dollars). The cost of a direct liquefaction facility of similar size (50,000 bpd) will probably be less, but even more uncertainty is associated with these costs. Until the cost uncertainty is reduced, the risk of project cancellation will remain high.

Second, only the Fischer-Tropsch and methanol synthesis indirect liquefaction processes have been commercially demonstrated. Significant technical uncertainties exist regarding the scaling-up of the direct liquefaction facilities. Although these uncertainties are not sufficient to screen out direct liquefaction projects, they contribute to the overall high level of project completion risk.

Third, commercial coal liquefaction projects will be large and consume enormous amounts of coal and water. Accordingly, there is significant potential for delays involving litigation over water rights, water and air quality control requirements, mine and plant siting, and coal contracts.

Finally, because of the massive investment required, the project completion risk will be high until financing is arranged. Market factors could lead to unanticipated delays in obtaining financing, which, in turn, could lead

to a postponement of the project. Moreover, if the financing costs turn out to be higher than expected, the project may be cancelled entirely.

Because of these project risk factors, we recommend that coal liquefaction projects meet five criteria before passing the project completion risk screen. Specifically, OFC should ensure that project sponsors have:

1. Obtained all major environmental permits
2. Acquired undisputed rights to water
3. Obtained firm contracts for the coal feedstock
4. Obtained firm commitments for project financing
5. Settled any significant lawsuits or regulatory actions.

Technology Readiness

Technology readiness ranks number two in the screening hierarchy for coal liquefaction projects. Indirect coal liquefaction methods are at a more advanced state of market readiness than direct liquefaction methods (see Exhibit 2.a). The leading indirect liquefaction technologies, Fischer-Tropsch and methanol synthesis, are commercially available and technically ready for full-scale commercial development. More specifically, the Fischer-Tropsch process was used in Germany to provide 15,000 barrels per day of military fuel during World War II. Currently, the Sasol complex in South Africa is using this process in two commercial plants. The Sasol-I plant, which has been in operation for 25 years, produces about 10,000 barrels of coal liquids per day; the Sasol-II plant, which goes on stream in 1981, produces 40,000 barrels per day.

Although it has not been commercially demonstrated, methanol synthesis is at a high state of technical readiness. The process uses commercially available and proven medium Btu gasifiers coupled with a methanol reactor. Both Lurgi and Imperial Chemical Industries have commercially available reactors that have been successfully tested at the demonstration plant level.

Direct liquefaction technologies are not at the same level of market readiness as indirect methods: none have

Exhibit 2.a

COMMERCIALIZATION STATUS OF SELECT COAL LIQUEFACTION PROCESSES

Process	Type of Process	Product Yields	Developer	Commercialization Status
Fischer-Tropsch	Indirect liquefaction	Diesel oil Gasoline SNG Fuel oil Alcohols	Sasol	Proven commercially at Sasol complex in South Africa
Methanol Synthesis	Indirect liquefaction	Methanol Heavy oil	Lurgi Imperial Chemical Industries Vulcan-Cincinnati	Commercially available components, proven at demonstration plant level
H-Coal	Direct liquefaction catalytic hydro-generation	Syncrude or fuel oil	Hydrocarbon Research, Inc.	Pilot plant (600 tpd) began operation in 1980; large-scale plant (50,000 tpd) under design
SRC-I	Direct liquefaction solvent extraction	Solid boiler fuel Liquid boiler fuel Gasoline Gas turbine fuel Residual oil substitute	Gulf Oil Corp.	Pilot plant (6 tpd) operating, design completed for 6600 tpd demonstration plant
SRC-II	Direct liquefaction solvent extraction	Fuel oil Naptha SNG	Gulf Oil Corp.	Pilot plant (35 tpd) tests begun in 1975
Exxon Donor Solvent (EDS)	Direct liquefaction solvent extraction	Syncrude Low sulfur fuel oil	Exxon	Pilot plant (250 tpd) began operating in 1980
COGAS	Direct liquefaction pyrolysis	Syncrude MEG	FMC Corporation	Pilot plant (36 tpd) operating, design completed for large commercial plant (22,000 tpd)

Source: Fluor Engineers and Construction, Inc. Report SFR-103, 1981.

been commercially demonstrated.* However, five processes have been successfully tested at the pilot plant level and reached the design stage for demonstration testing. These five processes (i.e., H-Coal, SRC-I, SRC-II, Exxon Donor Solvent, and COGAS) minimally meet our criteria for passing the technology readiness screen. A number of other direct processes are being actively developed and may pass the screen in the next 4 years. These processes include TOSCOAL, Occidental, IGT-Riser, Cities Service/Rockwell, Conoco-CSF, Dow, GVV, and Saarberg. Each of these processes have been tested at the process development unit level and are moving toward full pilot plant testing.

Fuel Availability

Fuel availability ranks third in the screening hierarchy for coal liquefaction projects. Although commercial coal liquefaction plants will produce large amounts of liquid fuels, the quantity of diesel fuel and fuel oil in the product slate will be highly project specific. Therefore, the fuel requirements of the user must be compared with the product slate of each coal liquefaction facility and the quantities of each fuel type that are not contractually committed to other purchasers.

Transportation Cost

The fourth ranked screen for coal liquefaction projects is transportation cost. Transportation of liquid fuels from coal should not prove a major constraint.

Transportation costs for coal liquids will depend on two major factors: the type of fuels produced at the coal liquefaction facility and the location of the facility in relation to existing transportation networks. Methanol from coal must be transported by tank cars and tank barges because there are no existing or planned interstate

* The Lurgi-Ruhrgas pyrolytic process has been commercially demonstrated in Yugoslavia. However, the products of this process, char and coal tar, are not direct substitutes for oil or natural gas. Therefore, it is not likely that they will play a significant role as an alternative fuel under FUA.

pipelines for methanol. New coal liquids (synthetic crude oil) can be transported by rail or barge. Crude oil pipelines may also be used to transport synthetic crude to refineries, if the synthetic crude contains no corrosive elements. Upgraded coal liquids (fuel oil and diesel fuel) may be transported by barge, rail, or pipeline, depending on the project's location. Fuel swapping opportunities exist for users that are outside the economic range for receiving fuel directly from the supplier. The specific transportation opportunities must be evaluated on a case-by-case basis.

For new facilities designed to use methanol, conversion to methanol at the end of the exemption period will involve only minor retrofitting. Methanol has about half the heat value of diesel fuel: 2.7 million Btu per barrel compared to 5.8 million for diesel fuel. As a result, the metering system must be modified to accommodate the large volume of methanol required to maintain the turbine's power rating.

With regard to load factor requirements, there are no constraints for coal liquid suppliers and users. Because the fuels have conventionally produced counterparts and can be stored, neither the user nor the supplier is particularly vulnerable to the other's load factor.

Cost Competitiveness

Cost competitiveness is the fifth ranking screen for coal liquefaction projects. Recent cost estimates for indirect coal liquefaction range from \$7.80 to \$8.90 per million Btu and \$6.20 to \$8.70 per million Btu for direct liquefaction.* However, regardless of production costs, coal liquids, because they are direct substitutes for petroleum products, will be priced competitively. Otherwise, the project sponsors will not find buyers for their coal liquid fuels.

Environmental Restrictions

The environmental restrictions screen ranks sixth for coal liquefaction projects. Environmental restrictions

* Source: Federal Emergency Management Agency, Energy and Defense Project, 1980. Prices escalated to 1981 dollars using the consumer price index.

may restrain the use of coal liquids, depending on the chemical composition of the fuel and the end-use location.

Generally, upgraded diesel fuel and fuel oil from coal are low in sulfur and will meet sulfur dioxide standards at any end-use location. Methanol, because it is a clean burning fuel, should also meet air quality standards. However, there is some concern that liquid products from direct coal liquefaction may contain potentially toxic and carcinogenic organic compounds that could be released during combustion at the end-use location. Therefore, when applying this screen, the chemical composition of the specific fuel should be determined.

Supplier/User Compatibility

Supplier/user compatibility is ranked last in the screening hierarchy for coal liquefaction projects. In general, fuel characteristics and load factor requirements for the supplier and user are compatible.

With regard to fuel characteristics, diesel fuel and fuel oil for coal are interchangeable with their petroleum-derived counterparts. As a result, retrofitting will not be required for conversion. However, conversion of gas turbines to methanol may be precluded for some existing facilities if the turbine blades and other parts were not designed to withstand the higher corrosivity of methanol.

The load characteristics of the user and supplier need not match, because refined coal liquids and methanol can be stored, and alternative supplies of comparable liquids exist.

LIQUID FUELS FROM OIL SHALE

Liquid fuels from oil shale are obtained through the pyrolysis of kerogen, the organic component of oil shale. This process involves heating the oil shale in a confined space, known as a retort, at temperatures above 400°F. The heat breaks down the kerogen into vaporized oil and other products; the vaporized oil is then condensed to form a viscous crude shale oil.

There are three generic processes for producing shale oil: aboveground, modified in-situ, and true in-situ. In the aboveground process, mined shale enters the retort chamber (located aboveground), where it is heated to extract the oil. In the modified in-situ process, some of the shale is mined, creating cavities underground. The remaining shale is broken up with explosives, filling the cavity with rubblized shale. The rubblized shale is then ignited, and the released oil is drawn off through wells. In the true in-situ process, the oil shale bed is fractured to increase permeability, a hot fluid is injected into the bed (or the bed is ignited), and the oil and gases are recovered through wells.

Shale oil obtained from these processes can be upgraded, typically by reacting the shale oil with hydrogen in the presence of a catalyst. The upgraded shale oil is a synthetic crude that can be further refined into finished products, including light and heavy fuel oils.

The raw shale oil can be used as a boiler fuel and, according to studies being conducted by the Electric Power Research Institute, as a combustion turbine fuel. Upgraded and refined shale oil fuels can be used in boilers, gas turbines, and combined cycle applications.

In matching suppliers of liquid fuels from oil shale with a specific user, OFC should apply the seven screens in the following order:

1. Project completion risk
2. Technology readiness
3. Fuel availability
4. Transportation cost
5. Cost competitiveness
6. Environmental restrictions
7. Supplier/user compatibility.

We describe the application of these screens below.

Project Completion Risk

Project completion risk ranks first in the screening hierarchy for oil shale projects. The risk of oil shale pro-

jects being cancelled or delayed is generally high but should be evaluated on a case-by-case basis. The factors giving rise to high project risk are the same as for large coal liquefaction and SNG projects. In particular:

- Because none of the oil shale processing technologies have been commercially proven, significant risk exists, even for the most thoroughly tested processes, that technical problems will force postponement, cancellation, or delay.
- Oil shale projects require large capital investments of \$1 to \$2 billion, or more. Given the size of the investment, significant risk exists that financing will not be obtained, or that financing negotiations will delay construction start-up.
- Considerable uncertainty exists concerning the cost of commercial oil shale facilities. Projects will be sensitive to technological or market factors that reduce the projected return on the oil shale investment. For example, a significant slowing, or reversal, in the 10-year trend of increasing crude oil prices could cause the abandonment or postponement of some oil shale projects, especially those in the preconstruction phase.
- Oil shale mining and processing have significant environmental effects, including potential air and water pollution and solid waste disposal problems. As a result, the potential for delay from regulatory proceedings and lawsuits is significant.
- Legal delays may arise from disputes over land and water rights ownership. For example, the White River oil shale project has been delayed because of a dispute between the federal government and the Ute Indians over oil shale resource ownership, while the Rio Blanco project may be delayed because of the problems associated with access to federal land for spent shale disposal.

Because of these potential problems, we recommend that oil shale projects meet the following criteria before passing the project completion risk screen. The project sponsors should have:

- Obtained all major environmental clearances
- Acquired undisputed rights to oil shale, water, and off-site shale disposal areas, as required by the project design

- Obtained firm commitments for project financing
- Face no major lawsuits or regulatory delays.

Technology Readiness

Technology readiness is the second ranking screen for oil shale projects. However, seven aboveground and two modified in-situ retorting processes (see Exhibit 2.b) have been successfully tested at the pilot plant stage. No oil shale technologies have been commercially demonstrated. Of the seven aboveground retorts, only the Paraho direct extracts oil by heating the oil shale directly. Four others (Paraho indirect, Petrosix, Union B, and Superior) extract oil by heating the oil shale with hot gases; two (i.e., TOSCO II and Lurgi-Ruhrgas) extract oil by bringing the oil shale in contact with hot solids. These nine processes meet our criteria for passing the technology readiness screen: they have been successfully tested at the pilot plant stage.

Several other processes are being developed that may meet our screening criteria within a few years. These include the HYTORT aboveground retort (using a direct heating concept), the Geokinetics true in-situ process, the Multi Mineral modified in-situ retort, and the T-3 batch retort developed by Science Applications, Inc.

Fuel Availability

Fuel availability ranks third in the screening hierarchy. Most commercial oil shale facilities will produce large amounts of liquid fuels: a typical size facility produces 50,000 barrels per day. Fuel commitments to others will often be the most important factor in determining fuel availability for a specific user. For some projects, for example, a large part of the output may be committed to the Defense Department under the terms of purchase commitments awarded under the Defense Production Act.

The amount of specific oil shale fuels available to users will depend on whether the shale oil output will be refined into finished fuels and whether there are prior contracts for these fuels. With refining, the amount of fuel available for gas turbine and steam boiler users decreases because the lighter distillates are not useful for these purposes. Because the quantity of diesel fuel

Exhibit 2.b

COMMERCIALIZATION STATUS OF SELECTED OIL SHALE PROCESSES

Process	Type of Process	Product Yields	Developer	Commercialization Status
Paraho Direct	Aboveground retort directly heated	Heavy shale oil Product gas	Paraho Development Corp.	Pilot plant (400 tpd) operating since 1973
Paraho Indirect	Aboveground retort indirectly heated by gas	Heavy shale oil Product gas	Paraho Development Corp.	Pilot plant (400 tpd) operating since 1973
Petrosix	Aboveground retort indirectly heated by gas	Heavy shale oil Light shale oil High Btu gas	Petrobras (Brazil)	Pilot plant (2200 tpd) operating since 1972; commercial demonstration plant planned for 1983.
Union B	Aboveground retort indirectly heated by gas	Heavy shale oil Product gas	Union Oil Company	Pilot plant (1200 tpd) using predecessor design tested during 1950s; environmental and engineering studies completed for demonstration plant, which is planned for 1935
Superior	Aboveground retort indirectly heated by gas	Heavy shale oil	Superior Oil Company	Two pilot plants operating; demonstration plant design begun
TOSCO II	Aboveground retort indirectly heated by ceramic balls	Heavy shale oil Naptha	Tosco Corp.	Pilot plant (1000 tpd) operated in 1960s; preliminary engineering designs and cost estimate for commercial scale plant in 1968; commercial plant planned for 1985
Lurgi-Ruhrgas	Aboveground retort indirectly heated by shale solids	Heavy shale oil High Btu gas	Ruhrgas A.G. (FRG) Lurgi G.m.b.H. (FRG)	Pilot plant (20 tpd) tested in West Germany; commercial-scale retort in design stage
Occidental	Modified in-situ	Heavy shale oil	Occidental Oil Shale Inc.	Three pilot retort test burns operated successfully; near-commercial size retort successfully tested in 1978
Rio Blanco	Modified in-situ	Heavy shale oil	Rio Blanco Oil Shale Inc.	Successful test of retort in 1980; second test in 1981; plans for commercial runs in 1982

and heavy fuel oil produced will average about 30 to 35 percent of the total project output, the quantities of these fuels from large oil shale projects will be sufficient for most utility and industrial users covered by FUA.

Transportation Cost

Transportation cost is the fourth screen. The feasibility of transporting oil shale fuels depends on the distance involved and the type of fuel. Transportation constraints will be few for synthetic crude oil and refined products but will be significant for raw shale oil.

Synthetic crude can be transported by existing crude oil pipelines, barge, and tank truck. Existing crude oil pipelines can transport synthetic crude from the shale oil-producing regions of Colorado and Utah west to Salt Lake City and east to the major refining centers and ports of the upper Midwest (e.g., Chicago, St. Louis, and Kansas City). From there, the oil could be shipped by barge or truck to East and Gulf Coast locations. Synthetic crude from eastern shale oil projects could move west by existing pipeline or by barge down at the Ohio and Mississippi rivers.

There is also considerable flexibility in moving refined shale oil products. Most likely, upgraded shale oil from Colorado and Utah will move through existing pipelines to refineries in Salt Lake City, Denver, or the upper Midwest. Refined products can then move by pipelines to the Pacific Northwest and by pipeline and barge to the major market areas in the Midwest and the Eastern Seaboard. Refined products from Eastern shale can move from nearby refineries by pipeline and tanker truck to markets in the upper Midwest and by water to markets along the Ohio, Mississippi, and Illinois River systems, and from New Orleans to Gulf and East Coast markets. In addition, because synthetic crude and refined shale oil products have petroleum-derived equivalents, the feasible market areas can be enlarged through swapping arrangements. Users in California, for example, could purchase shale products in Salt Lake City and swap the product for a petroleum-derived equivalent produced in California.

Raw shale oil, on the other hand, cannot be economically transported for long distances because it cannot use existing pipelines. Raw shale oil is highly viscous, with a specific gravity of 20-22°API and a pour point of 70-90°F. To be transported by pipelines, the raw shale oil must be blended with conventional crude oil with

higher specific gravity (30-40⁰API) and lower pour point (-40⁰ to 0⁰F). Moreover, the pipeline must be insulated and heated. As a result, raw shale oil will probably be transported by truck, rail, or water. The lack of water transportation routes in the West may significantly constrain oil shale transportation economics.

Cost Competitiveness

Cost competitiveness is the fifth ranking screen for oil shale projects. According to recent estimates, synthetic crude from oil shale fuels can be produced for \$4.70 to \$6.80 per million Btu (\$28.20 to \$36.50 per barrel) in aboveground retorts and \$3.20 to \$5.10 per million Btu (\$19.20 to \$34.80 per barrel) using an MIS process.* These costs are marginally competitive with the price of imported crude. Because raw, upgraded, and refined shale oil will compete with crude oil and refined petroleum products, fuels from oil shale must be priced competitively with petroleum-derived substitutes to attract buyers. Therefore, fuels from shale oil will be priced within the cost test ceiling of \$7 to \$8 per million Btu.

Environmental Restrictions

There will be few, if any, environmental restrictions on the use of upgraded and refined shale oil fuels in boilers and gas turbines; therefore, it is the sixth screen. Raw shale oil, however, may face restrictions because of its high nitrogen content (about 2 percent by weight) and the presence of trace elements, such as arsenic, nickel, and vanadium, and carcinogens such as benzo-a-pyrene.

Supplier/User Compatibility

Supplier/user compatibility with respect to fuel and load characteristics may pose constraints on the use of raw shale oil but not upgraded or refined fuels; therefore, it is the seventh screen.

With respect to fuel characteristics, the presence of nitrogen, trace elements, gums, and waxes may foul conventional burner equipment. Because upgrading removes these impurities, upgraded and refined shale oil fuels are compatible with conventional burner equipment.

* Source: Hagler-Bailly and Company, 1980. Costs escalated to 1981 dollars using the consumer price index.

If raw shale oil is being burned, the supplier's load profile must match that of the user. Because of the properties of raw shale oil, it deteriorates rapidly in storage. Consequently, a project's output must be burned shortly after production. The only way of ensuring this is to match the demand load profile with the supply load profile for raw shale oil.

ETHANOL FROM BIOMASS

Ethanol, a clean-burning alcohol fuel, can be produced from a number of biomass feedstocks, including grains, sugar crops, municipal solid wastes, plant herbage, food processing wastes, and wood. Most of the major commercial ethanol facilities, either operating or planned, in the United States use corn as the feedstock.

The conversion of biomass into fuel-grade ethanol involves four steps: conversion to sugar, fermentation, distillation, and dehydration. First, the feedstock is converted to fermentable sugars. If the feedstock is corn or other grains, this step involves creating a mash by grinding the feedstock and mixing it with water. This mash is then cooked, and fungal amylase added, to convert the carbohydrates to simple sugar. For sugar crops, the sugar is extracted directly through crushing or thermochemical diffusion. For wood products and dry agricultural wastes, cellulose is converted to sugar through acid or enzymatic hydrolysis. Second, yeast is added to the mash, which is then converted to a low proof alcohol through fermentation. Then the fermented mash is distilled into 190 proof (95 percent) alcohol. Finally, the alcohol from the distillation process enters a dehydration tower, where most of the water is removed, leaving 200-proof fuel-grade ethanol.

Ethanol is primarily used as a transportation fuel. In particular, ethanol may be blended with gasoline to produce gasohol (90-percent gasoline, 10-percent ethanol). Technically, ethanol may also be used as a boiler or gas turbine fuel.

In matching ethanol suppliers with a specific user, OFC should apply the seven screens in the following order:

1. Cost competitiveness
2. Project completion risk
3. Transportation cost
4. Fuel availability

5. Supplier/user compatibility
6. Technology readiness
7. Environmental restrictions.

We describe the application of these screens below.

Cost Competitiveness

Currently, ethanol is not a cost-competitive boiler or gas turbine fuel option for utility and industrial applications covered by FUA. Until this situation changes, we recommend that no ethanol projects pass the cost competitiveness screen. This recommendation is based on two considerations:

1. Compared to petroleum products, ethanol is expensive to produce. Recent cost estimates for ethanol range from \$11.60 to \$28.10 per million Btu (1981 dollars), depending on the cost of the feedstock and other factors.* These costs, which are far higher than fuel oil prices of \$6 and \$8 per million Btu, are above the cost test ceiling of \$7 to \$8 per million Btu.
2. The market price of ethanol will be determined by its highest valued use, namely as a component of gasohol. The value of ethanol in gasohol is \$1.70 to \$3.00 per gallon compared to a value of \$0.60 per gallon as a gas turbine fuel. This large differential prevents ethanol producers from pricing ethanol competitively as a gas turbine fuel.

The value differential for ethanol as a gasohol ingredient occurs for the following reasons. First, in gasohol blends, 1 gallon of ethanol substitutes for 1 gallon of unleaded gasoline, priced at \$1.20 to \$1.10 per gallon. The same gallon of ethanol burned in a gas turbine will substitute for only 0.6 gallon of

* Source: Office of Technology Assessment, Energy from Biological Processes, 1980. Costs escalated to 1981 using the consumer price index.

diesel fuel priced at \$0.93 to \$1.05 per gallon.* When the diesel fuel price is multiplied by 0.6, ethanol is worth only \$0.60 per gallon as a gas turbine fuel. Second, ethanol has a value of about \$0.30 to \$0.50 per gallon as a blending agent with gasohol because it boosts octane.** Third, ethanol used in gasohol receives tax incentives, in the form of federal and state gasoline excise tax exemptions, of \$0.40 to \$1.35 per gallon of ethanol.† Adding the octane boosting premium and tax incentives to the price of unleaded gasoline yields an effective value as a gasohol ingredient of \$1.70 to \$3.00 per gallon, compared to \$0.60 as a gas turbine fuel,

Project Completion Risk

Project completion risk ranks second in the screening hierarchy for ethanol projects. The risk of delay or cancellation of ethanol projects is generally low. The technology is commercially proven, and the potential for delays caused by regulatory or legal disputes is low. The major factor that may cause cancellation is the volatility of feedstock prices, which depend on weather

* For gasohol, there is no adjustment for the lower Btu value of ethanol compared to gasoline because ethanol produces better gas mileage than gasoline on a per Btu basis. For gas turbine fuel, the value of ethanol is 0.6 times the price of No. 2 distillate based on the relative heat values of the two fuels (84,000 Btu per gallon of ethanol divided by 143,000 Btu per gallon of No. 2 distillate). Prices are based on May 1981 wholesale prices at various U.S. locations.

** Assuming ethanol boosts the octane rating 2 to 3 points, gasohol will sell (wholesale) for \$0.03 to \$0.05 per gallon higher than regular unleaded. Because the ethanol content of gasohol is 10 percent, the octane boosting value per gallon of ethanol is 10 times this price differential (\$0.30 to \$0.50 per gallon).

† The combined exemption from the federal and state excise tax is from \$0.04 to \$0.135 per gallon of gasohol. Because the ethanol content of the gasohol is only 10 percent, the tax benefit is equivalent to \$0.40 to \$1.35 per gallon of ethanol.

and market conditions. Once financing is in place, however, few ethanol projects will be cancelled or postponed.

Transportation Cost

Transportation cost is the third screen. Generally, ethanol is transported in stainless steel tank trucks. Ethanol cannot be transported in existing petroleum product pipelines because it is corrosive and will pick up water and sediments. Consequently, the transportation economics favor local markets for ethanol. For this reason, producers over 600 miles from the user should not be considered feasible suppliers.

Fuel Availability

In general, large ethanol projects will meet the fuel requirements for most users; therefore, fuel availability is the fourth screen. Availability of fuel from ethanol projects, however, must be determined on a case-by-case basis to ensure that output is not committed under long-term contracts to gasohol producers.

Supplier/User Compatibility

Supplier/user compatibility is the fifth ranking screen. Load factor compatibility is not a problem, because ethanol can be readily stored. However, the fuel characteristics of ethanol may pose a compatibility problem, depending on the cost of converting from diesel fuel or natural gas to ethanol. Because ethanol corrodes magnesium and aluminium and also deteriorates rubber components, the cost of modifying a system will depend on the materials used in the gas turbine. Moreover, modification of the metering is required to accommodate the higher volume of flow necessary to compensate for the lower heat value of ethanol compared to diesel fuel.

Technology Readiness

Technology readiness ranks sixth in the screening hierarchy for ethanol projects. Ethanol from grain and sugar crops meets our criteria for passing the technology readiness screen; ethanol from cellulosic material (wood, crop residues, municipal solid waste) does not.

More specifically, the basic process for producing ethanol from grain and sugar crops has been used for years in the production of high-proof alcohol beverages and grain alcohol. Currently, there are five major fuel-grade ethanol producers in the United States, with a combined capacity of 105 million gallons per year. Half of this capacity is with Archer-Daniels-Midland Company, which has been producing ethanol since 1978.

However, ethanol production from cellulose materials, including wood, crop residues, and municipal solid waste, has not been demonstrated at a commercial scale.* Currently, research is under way on different methods for pretreating cellulosic feedstocks and for enzymatic conversion, but these processes are at the pre-pilot plant stage of development.

Environmental Restrictions

Currently, no environmental restrictions are in effect that limit the use of ethanol in power-generating facilities or industrial boilers. As a result, the environmental restrictions screen is ranked seventh.

GASEOUS FUELS FROM BIOMASS

Three different processes are used to produce gaseous fuels from biomass: recovery of methane from landfill, pyrolytic gasification of municipal solid waste (MSW), and controlled anaerobic digestion of MSW or animal waste. However, only the recovery of methane from landfill is being proposed for projects that could supply users under the terms of the synthetic fuels exemption. Development work is underway on pyrolysis systems for producing gaseous and liquid fuels from MSW and anaerobic digestion systems for converting manure to medium Btu methane gas. Once commercial projects are announced, OFC should add these processes to the matching system.

* Currently, Georgia-Pacific operates a commercial wood-to-ethanol plant in Bellingham, Washington. However, the plant, which was built by the federal government during World War II, uses a complex acid hydrolysis process that is not considered commercially viable.

Methane is produced naturally in most landfills through anaerobic digestion of organic solid wastes. A two-step bacteriological process is involved in the production of methane: acid-forming bacteria convert the wastes to organic acids; and methane-producing bacteria convert these acids to methane gas. Although this process occurs naturally in most landfills, gas production can be increased by increasing the moisture and/or nutrient air content of the wastes and by restricting air infiltration and heat loss through the cover material.

The methane is recovered (along with other gases) by drilling gas recovery wells, through the landfill cover, into the buried wastes. Typically, the gas recovered contains 50-percent methane and 50-percent carbon dioxide, with a heat value of 450 to 650 Btu per scf. After condensates and particulates are removed, the gas is compressed, cooled, and dehydrated. The resulting gas can be used in steam boilers, gas turbines, or gas engines located near the landfill. Alternatively, the gas can be upgraded to a high Btu, pipeline-quality gas and injected into natural gas pipelines.

The order in which the screens are to be applied to gaseous fuels from biomass projects is:

1. Fuel availability
2. Transportation cost
3. Supplier/user compatibility
4. Project completion risk
5. Technology readiness
6. Cost competitiveness
7. Environmental restrictions.

We describe their application below.

Fuel Availability

Fuel availability is the most important constraining factor in matching landfill methane producers with users. Most commercial methane from landfill projects will produce only 1 to 5 million Btu per day and typically for only 10 to 20 years, which is sufficient for only the smallest users covered by FUA. Moreover, some or

all of the project's output may be committed to other users. A landfill gas project should not be considered a feasible supplier for users whose energy requirements are double the project's available daily output.

Transportation Cost

Transportation cost is the second ranking screen. The economics of transporting landfill methane depends on its heat value. Medium Btu gas must be transported via specially constructed pipelines. Moreover, the quantity of medium Btu gas produced is small. Consequently, pipelines longer than a mile or so would result in excessive transportation costs per Btu of delivered fuel, while the small market in medium Btu landfill gas eliminates the possibility of swapping arrangements.

In contrast, high Btu landfill gas can be compressed and injected directly into natural gas lines. Accordingly, virtually no transportation constraints on the use of high Btu landfill gas exist. In addition, because it is a perfect substitute for natural gas, high Btu landfill gas can be purchased by a user and swapped for natural gas.

Supplier/User Compatibility

Supplier/user compatibility is ranked third in the screening hierarchy. Supplier/user compatibility issues are important for medium Btu landfill gas projects but not for high Btu projects.

With respect to load factor compatibility, landfill gas production cannot be easily varied, and the gas cannot be stored. Users of MBG from landfills must have a high load factor, indicating a continuous and constant level of demand. High Btu gas users are not so constrained because the gas can be absorbed in the natural gas distribution system.

With respect to fuel characteristics, users of medium Btu gas must compensate for the lower Btu content of MBG. Consequently, some minor retrofitting of equipment is required when switching from natural gas to MBG to increase the volume of gas entering the user's facility. These modifications are not required for users of high Btu landfill gas.

Project Completion Risk

The risk of a project being abandoned or significantly delayed is low for landfill methane projects; therefore, this is the fourth ranking screen. The technology is well developed, and the time from feasibility study to peak production is only 12 to 18 months. As a result, few opportunities exist for significant delays because of engineering problems. Low risks are associated with project cancellation or postponement for economic reasons. Moreover, the total capital costs for landfill methane projects are low (i.e., from \$4 to \$10 million). Consequently, delays resulting from financing problems are much less likely than for the more capital-intensive synthetic fuels processes (e.g., oil shale, coal gasification and coal liquefaction). In addition, because unit production costs are low, there is little risk that the project will be cancelled because of changes in economic conditions. Finally, regulatory and legal delays are unlikely because environmental and socioeconomic impacts are low and because resource ownership issues are relatively clear-cut.

Technology Readiness

Methane from landfill is at a high state of technological readiness; consequently, technology readiness is ranked fifth in the screening process. The techniques for production enhancement, gas recovery, and upgrading have been developed and used commercially. For example, Getty Synthetic Fuels, the largest commercial producer of landfill methane, has three operating commercial sites and others under development.

Cost Competitiveness

Methane recovered from landfills can be priced competitively with alternative fuels, including natural gas and diesel fuels. Recent estimates indicate a production cost per million Btu of \$1.35 to \$2.90 for medium Btu gas and \$2.15 to \$3.85 for high Btu gas.* These costs are

* Costs are expressed in 1981 dollars and are based on estimates in Johns Hopkins University Applied Physics Laboratory, Landfill Methane Utilization Technology Workbook, February 1981.

well below the costs of petroleum or natural gas and under the cost test ceiling. As a result, cost competitiveness ranks sixth as a screen.

Environmental Restrictions

The seventh screen is environmental restrictions. Environmental restrictions on the use of landfill gas are minimal. Medium and high Btu gas from landfills are clean-burning fuels. Consequently, they should meet air quality standards in any end-use location.

3

MODIFICATION OF SCREENS TO EVALUATE THE FEASIBILITY OF ON-SITE DEVELOPMENT OF LOW AND MEDIUM BTU GASIFICATION

In the preceding chapters, we presented a hierarchical screening procedure for evaluating the feasibility of matching a prospective user of synthetic fuel with a prospective producer. The screening procedure is specifically designed to facilitate sorting among known producer projects to find those that have a reasonable probability of meeting a user's requirements satisfactorily. However, the application of the screening criteria for prospective LBG and MBG users indicates that there will be few, if any, opportunities to match a prospective user with an LBG or MBG producer. Rather, the economics of transporting finished fuel dictates that LBG and MBG production facilities be located in the immediate proximity of the user or on the same site. As a result, the prospective user will design the LBG or MBG production facility to meet his own needs and construct it at or very near the site where the fuel will be used.

Given this situation, we present a revised hierarchical screening procedure in this chapter that can be used in assessing the feasibility of on-site development of LBG or MBG. This revised screening procedure will assist OFC in verifying the reasonableness of a petition for the synthetic fuel exemption based on on-site production of LBG or MBG. In addition, application of the procedure will assist OFC in determining whether on-site development of LBG or MBG could be a reasonable alternative for petitioners for a FUA exemption that claim to have no access to fuels other than oil or gas.

To develop the revised screening procedure, we modified and, in some instances, replaced the screen presented in Chapter 1 to reflect the considerations that determine the feasibility of on-site production of LBG or MBG. These considerations include such problems as coal acqui-

sition, increased environmental restrictions stemming from on-site gasification, and the ability to integrate gasifiers with the end-use production process. The five revised screens are:

1. Site selection and area requirements. This new screen focuses on the specific siting requirements for an on-site LBG or MBG facility, including coal-receiving facilities and adequate land area.
2. User compatibility. This screen is essentially the same as in the preceding chapters.
3. Environmental restrictions. This screen now focuses on the environmental limitations that apply to producing LBG or MBG rather than those that apply to combustion of a synthetic fuel.
4. Access to feedstock and cost competitiveness. This screen combines elements of three screens from the preceding chapters: fuel availability, transportation cost, and cost competitiveness. This screen focuses on the distance of the user from suitable coal supplies and the effect of coal transportation cost and variability in LBG and MBG production cost on cost competitiveness.
5. Project completion risk. This screen is essentially unchanged.

We eliminated the screen for technology readiness because a sufficient range of LBG and MBG technologies have been commercially accepted to permit choice of a suitable gasification process.

In the following, we describe the application of these screens to the evaluation of on-site development of LBG and MBG.

LOW BTU GAS FROM COAL

Of the 27 LBG projects described in Appendix B, 8 are on-site commercial facilities in operation; 2 are on-site commercial facilities currently in planning and construction phases; the remaining projects are at the pilot program or process development stage. Current applications for the product gas include firing brick kilns, metal-processing furnaces, and space-heating furnaces

for an industrial park and a branch campus of a major state university. Moreover, LBG has been demonstrated to be successful in steam boiler electric generation.

In evaluating the feasibility of on-site LBG facilities, OFC should apply the screens to a prospective user in the following order:

- Site selection and area requirements
- User compatibility
- Environmental restrictions
- Access to feedstock and cost competitiveness
- Project completion risk.

We describe the application of these screens below.

Site Selection and Area Requirements

On-site development of LBG requires that the prospective user have the facilities to receive coal deliveries and adequate space for a gasifier(s) and coal storage and handling. To receive coal efficiently in large quantities, the user should be near a rail line or barge terminal. In some instances, coal could be received by truck, but this shipment procedure is usually cumbersome and costly. Firms such as former coal-burning utilities should have few problems in gaining access to transportation as they need only to restore the rail spurs or barge facilities that were retired when natural gas or oil was introduced as primary fuels. However, projects located at sites without readily available access to transportation will probably fail this screen because of the costs associated with obtaining easements for spur track and constructing new rail or barge facilities.

In addition to needing coal-receiving capabilities, a prospective developer of on-site LBG would need sufficient area at the production site to integrate the gasifier and its associated facilities with the end-use production process. Construction engineers familiar with LBG installations indicate that an LBG facility capable of

producing 0.6-1.5 billion Btu/day requires 2.5-3.2 acres for the gasifier, coal storage site, coal preparation facilities, and waste disposal area.

We recommend that a prospective user pass this screen if:

- Facilities for receiving coal already exist or could readily be constructed at the site
- The area for gasifiers and its associated facilities is available at or adjacent to the user's site.

User Compatibility

User compatibility is the second ranking screen for on-site LBG projects. The characteristics of LBG limit its feasible use. LBG has a high nitrogen content, low carbon monoxide and hydrogen content, and a low heat content (125-175 Btu/SCF as compared to 1000 Btu/SCF for natural gas). As previously mentioned, these characteristics relegate LBG to on-site use, but they also limit industrial applications because of low flame temperature (2853°F compared to 3279°F for natural gas).

Likely applications for LBG are:

- Kiln firing of bricks
- Iron ore pelletizing
- Chemical furnaces
- Boiler fuel
- Electric power generation (for use in either a boiler or gas turbine).

A major issue concerning on-site LBG applications will be the cost of retrofitting plant and equipment to operate on LBG. Retrofitting requirements will vary with the different gasification technologies and end-use processes. In general, after allowing for adjustment of the fuel/air ratio, the heat content per unit of fuel/air mixture for LBG will be about 64 Btu/SCF compared to 86 Btu/SCF for natural gas. This reduction in Btu content per unit of flow means that the volume of combustion chambers may need to be increased to avoid a loss in operating capacity of boilers and other end-use equipment. However, design engineers indicate that increasing the rate of fuel/air flow should usually hold any derating of operating capacity to a small percentage (e.g., 5-10 percent).

In addition, the quantity and load characteristics of the user's fuel requirements should support the installation and efficient operation of a commercial-scale LBG unit. Specifically, the user's fuel requirement should be at least 500 mm Btu/day, with a load factor of 0.70 or higher. For existing facilities, the remaining useful life of the facility should be sufficient to amortize economically the cost of the LBG facility, or at least 15 years.

Finally, the quality of the final LBG product must meet end-use requirements. Specifically, the use of LBG in metal-processing or gas turbine applications will require a clean product, which will add to the production cost. In some boiler applications, the LBG may not need to be de-tarred or de-oiled, which, in turn, would tend to reduce production cost.

In light of these considerations, we recommend that a user pass this screen if:

- The application of on-site LBG to the particular end-use process has been recognized as commercially acceptable
- The fuel requirements, load factors, and (for existing facilities) remaining operating life of the user are sufficient to support commercial operations
- The user will not incur a significant loss of end-use operating capacity or can make design changes to avoid the potential derating.

Environmental Restrictions

Environmental restrictions ranks third among the criteria for evaluating the potential for on-site development of low Btu gasification. The production of LBG involves significant environmental impacts; in some instances, local restrictions may preclude or make the installation of an LBG project very costly. Specifically, the gasification process will emit air pollutants similar to those that occur in conventional coal combustion: sulfur oxides, particulates, and oxides of nitrogen. These pollutants are criteria pollutants, as defined by the Clean Air Act. Accordingly, it would be difficult, if not impossible, to locate an LBG facility in an area that has not attained primary ambient standards for one of these pollutants. Similar difficulties would be faced if the area were designated Class I under the no-significant deterioration (NSD) of air quality program. In addition, local and state requirements associated with water pollution and waste disposal could prevent installation of a plant in some locations.

We recommend that a prospective user pass this screen unless the user is located in a nonattainment region for sulfur oxides, particulates, or oxides of nitrogen, or in an NSD Class I region. Other stringent environmental requirements might also cause a project to fail this screen.

Access to Feedstock and Cost Competitiveness

The fourth screen reflects the need to acquire coal for the on-site gasifier and the effect of delivered coal cost on cost competitiveness. In general, gasification technology is sufficiently diverse that a user should be able to select a technology that will accept the coal most readily available to the user. For example, Koppers-Totzek gasifiers can operate on all grades of coal, Winkler gasifiers on noncaking coals, and Lurgi gasifiers on lignite and noncaking coals. Nevertheless, the user must ensure that the coal and gasification technology are compatible.

More importantly, the source of coal should be within a reasonable distance of the user. Otherwise, the per unit cost of gas may not be competitive with other fuels.

In analyzing the relationship between transportation distance and cost competitiveness, it is necessary to account for differences in mine-mouth price of coal by region and coal type and the differences in the production cost of LBG, depending on the quality of gas required and the cost performance of the LBG project. Assuming \$7.50/MMBtu as the highest competitive cost for LBG and using information on unit production cost (without considering the cost of coal) for different qualities of produced LBG, mine-mouth coal prices for different coals, and an average transportation cost of 2.5¢/ton-mile, we estimated the distance for transporting the different coals that would set the delivered cost of LBG at \$7.50/MMBtu. On the basis of this analysis, we found that in instances where a user can accept LBG that has not been de-tarred and de-oiled (e.g., some boiler applications) the cost of transporting coal to

the user's site by rail should not constrain development of on-site LBG. That is, at locations serviced by rail throughout the contiguous 48 states, a user should be able to haul coal from a nearby coal-producing region without pushing the delivered cost of LBG above \$7.50/MMBtu.

However, in instances where the user requires clean LBG (e.g., in a gas turbine or combined cycle operation), the additional LBG production cost may limit the maximum distance that different coals could be transported. Specifically, using the higher than average estimates of the cost of producing clean LBG (i.e., a production cost of \$7.20/MMBtu from bituminous coal at \$30.00/ton, 1981), we estimated that the maximum distance that a prospective user of clean LBG could transport coal and still produce LBG at a competitive cost would range from approximately 730 miles for subbituminous coal from the Northern Great Plains to about 185 miles for bituminous coal from the Appalachian coal fields. Exhibit 3.a lists the maximum possible coal and shipment distances and corresponding coal prices for seven coals from different regions and of different grades. Depending upon the location of the prospective LBG user with respect to different coal-producing regions and the cost performance of his project, the user may find that transportation costs will preclude producing clean LBG economically.

On the basis of these analyses, we recommend that a project pass this screen unless the user requires clean LBG, can expect higher than average costs (e.g., because of stricter than usual environmental controls on LBG plant emissions), and is located at a distance from the nearest coal fields that exceeds the maximum shipment distance for that coal as indicated in Exhibit 3.a.

Project Completion Risk

Project completion risk ranks fifth. Generally, it should not be a major problem for LBG units if the prospective user has passed the preceding screens. At this stage in the feasibility evaluation, the most important issue affecting project completion risk is whether the user could successfully finance the LBG project.

Exhibit 3.a

MAXIMUM ALLOWABLE DISTANCE FOR
TRANSPORTING COAL: LBG - CLEAN GAS
(Higher than Average Production Cost)*

Supply Region	Coal Price** (\$/Ton)	Allowable Distance (Miles)
North Central (Bituminous)	28.50	338
Appalachian Area (Bituminous)	32.25	187
Northern Great Plains (Subbituminous)	11.00	732
Northern Great Plains (Lignite)	9.25	503
Rocky Mountain Area (Bituminous)	21.00	640
Central-Southwest (Lignite)	11.00	430
Alabama Area (Bituminous)	31.00	240

* The higher than average production cost of clean LBG from bituminous coal, delivered at \$30.00 per ton, is \$7.20/MMBtu. This reflects a 15-percent cost of capital, a 70-percent load factor, and a cost of process retrofit equivalent to 20 percent of the cost of the gasifier.

** Coal prices are quoted in 1981 dollars.

NOTE: For all quantities of LBG produced in high, low, and average cost cases, a \$1.00/MMBtu increase in the price of coal will increase the production cost of LBG by \$1.00/MMBtu.

MEDIUM BTU GAS FROM COAL

The production of MBG from coal is nearly identical to LBG: the primary exception is the use of oxygen instead of air as the oxidizing agent in the process. The use of oxygen as an oxidant improves the quality of the product gas to the extent that it can be used in a wider variety of applications than LBG. MBG gas can be used in existing utility and industrial boilers, for intermediate and baseload combined cycle gas turbine applications, and as a feedstock in chemical production.

In Appendix B, we have identified and described 23 MBG projects. Of these, 18 are commercial facilities; 11 of the 18 are classified for on-site use, with output consigned to various end-use applications.

In the following, we describe the application of the screens to on-site MBG projects. Because of the similarity in technologies for LBG and MBG, the screens are in the same order. However, the application of the screens to MBG may vary from that applied to LBG projects because of subtle differences in technologies.

Site Selection and Area Requirements

The application of this screen to on-site MBG projects is essentially the same as for LBG projects. To manage coal deliveries, the site must be near a rail line or a barge terminal. An MBG facility, in comparison to an LBG facility, typically requires more coal. As a result, truck deliveries are probably out.

In addition, the user's site must have sufficient space to accommodate the MBG facility. However, for two reasons, the area requirements for MBG facilities are generally larger than for the LBG operation. These reasons are:

1. The addition of an oxygen plant for MBG production significantly increases the area requirements
2. To achieve reasonable economies-of-scale, an MBG operation must have considerably greater production capacity than an LBG operation.

Specifically, a small MBG operation with production capacity of 30 to 50 billion Btu/day would typically require 9 to 10 acres for the gasifier and coal storage area and associated facilities. A large operation of 120 to 140 billion Btu/day would require approximately 120 acres.

User Compatibility

User compatibility ranks second among the MBG screens. The key issue concerning user compatibility is the scale and continuousness of user fuel requirements. Because of the higher heat value and flame temperature of MBG relative to LBG, MBG may be used in essentially the same industrial applications as natural gas. Moreover, with an efficient fuel/air mixture, use of MBG should result in no loss of operating capacity relative to natural gas; indeed, boiler output may increase with MBG. As a result, retrofitting requirements for switching from gas to MBG should be minimal.

With regard to the scale and continuousness of the fuel requirement, the minimum average fuel use to support a commercial-scale unit would be about 10 billion Btu/day. To support economic operations, the load factor on such a unit should be 0.7 or higher. Larger MBG operations (i.e., 120-140 billion Btu/day) may be economic with a lower load factor. Given these scale requirements, appropriate single-user applications for an MBG facility would be utility boilers and industrial cogeneration operations (i.e., the industrial user would use the gas for process heat or as a chemical feedstock and to generate electricity for his own use and sale to utilities). In addition, for existing facilities, the remaining operating life should be at least 20 years.

Environmental Restrictions

Environmental restrictions, which rank third, may be a more important criterion for evaluating on-site development of MBG than for LBG. The qualitative nature of the environmental impacts of MBG development is essentially the same as for LBG; however, because MBG facilities will usually be larger in scale than LBG operations, the magnitude of impacts will be greater. Again, air pollution restrictions may prevent location of an MBG facility in a nonattainment area or in a NSD Class I area.

Access to Feedstock and Cost Competitiveness

The considerations in applying this screen to evaluate MBG feasibility are essentially the same as for LBG. Again, technologies are sufficiently diverse in their

coal requirement that a prospective user should be able to choose a commercially demonstrated technology that is compatible with the coal most readily available to the user. However, the effect of such variables as coal cost, distance of user from the coal-producing region, and MBG production cost on the cost competitiveness of MBG becomes more crucial in assessing feasibility because of the inherently higher cost per Btu output of MBG relative to LBG.

To assess the impact of these variables on cost-competitiveness of prospective on-site development of MBG, we undertook a parallel analysis to that described in the discussion of LBG. Specifically, we examined the cost competitiveness of MBG for small (40 billion Btu/day) and large (130 billion Btu/day) capacity operations and for average and higher than average cost of MBG production. Where shipment is feasible (i.e., the mine-mouth cost of MBG production is less than \$7.50/MMBtu), we computed the shipment distance for each of the seven different coals that would set the delivered cost of MBG at \$7.50/MMBtu.

On the basis of this analysis, we found that the cost of shipping coal to the prospective user's site may significantly limit the economic competitiveness of on-site production of MBG. Specifically, for the small capacity operation (40 billion Btu/day) with average cost of production (i.e., a production cost of \$7.35/MMBtu for subbituminous coal at a delivered price of \$25/ton, 1981), the maximum allowable distance for coal shipment ranged from approximately 45 miles for Appalachian bituminous coal to 630 miles for Northern Great Plains subbituminous coal (see Exhibit 3.b). At higher than average production cost, on-site development of a small capacity MBG operation does not appear economically feasible: the cost of MBG with even low coal costs would be greater than \$7.50/MMBtu.

Conditions for developing on-site MBG are more optimistic for a large capacity operation (130 billion Btu/day). For the large capacity operation with average estimates of production cost (i.e., a production cost of \$5.20/MMBtu from subbituminous coal at a delivered price of \$25/ton, 1981), the maximum allowable distance for coal shipment ranged from 1280 miles for Central-Southwest

Exhibit 3.b

MAXIMUM ALLOWABLE DISTANCE FOR
TRANSPORTING COAL: MBG - 40 BILLION
BTU/DAY FACILITY
(Average Production Cost)*

Supply Region	Coal Price** (\$/Ton)	Allowable Distance (Miles)
North Central (Bituminous)	28.50	230
Appalachian Area (Bituminous)	32.25	43
Northern Great Plains (Subbituminous)	11.00	629
Northern Great Plains (Lignite)	9.25	427
Rocky Mountain Area (Bituminous)	21.00	510
Central-Southwest (Lignite)	11.00	353
Alabama Area (Bituminous)	31.00	108

* The average production cost of MBG from subbituminous coal, delivered at \$25.00 per ton, is \$7.35/MMBtu. This reflects a 12-percent cost of capital, an 80-percent load factor, and a process retrofit equivalent to 10 percent of the cost of the gasifier.

** Coal prices are quoted in 1981 dollars.

NOTE: For MBG production, a \$1.00/MMBtu increase in the price of coal will increase the production cost of MBG by \$1.20/MMBtu.

lignite to 2080 miles for Rocky Mountain bituminous. Accordingly, coal shipment would not appear to be a constraining factor for the average production cost case. However, for the higher than average cost case (i.e., a production cost of \$7.40/mmBtu from subbituminous coal at a delivered price of \$25/ton, 1981), we found that the maximum allowable coal transportation distance would range from about 20 miles for Appalachian bituminous to 600 miles for Northern Great Plains subbituminous (see Exhibit 3.c). In this case, the location of the prospective user with respect to specific coal-producing regions could significantly alter the economic feasibility of on-site development of MBG.

To apply this screen in evaluating the feasibility of on-site MBG, OFC will need to consider the scale of MBG operations, the location of the prospective user, the distance to accessible coal-producing regions, and whether production cost is likely to be higher than average. Higher than average costs could occur because of high financing costs, low load factor on MBG use, strict environmental control requirements, or high construction costs. Taking these factors into account, OFC should be able to classify a prospective user's operation and determine, on the basis of the user's location relative to coal-producing regions, whether on-site development of MBG is economically feasible.

Project Completion Risk

Project completion risk is the fifth screen applied in evaluating on-site MBG feasibility. Assuming that completion risks associated with environmental permitting requirements have been resolved in the environmental restrictions screen, the major source of completion risk results from potential inability to finance the MBG project to completion.

Exhibit 3.c

MAXIMUM ALLOWABLE DISTANCE FOR
TRANSPORTING COAL: MBG -
130 BILLION BTU/DAY FACILITY

Supply Region	Coal Price* (\$/Ton)	Allowable Distance (Miles)	
		Average Cost Case**	Higher than Average Cost Case+
North Central (Bituminous)	28.50	1780	168
Appalachian Area (Bituminous)	32.25	1630	18
Northern Great Plains (Subbituminous)	11.00	1874	600
Northern Great Plains (Lignite)	9.25	1354	401
Rocky Mountain Area (Bituminous)	21.00	2080	468
Central- Southwest (Lignite)	11.00	1280	326
Alabama Area (Bituminous)	31.00	1680	68

* Coal prices are quoted in 1981 dollars.

** The average production cost of MBG from subbituminous coal, delivered at \$25.00/ton, is \$5.20/MMBtu. This reflects a 12-percent cost of capital, an 80-percent load factor, and a process retrofit equivalent to 10 percent of the cost of the gasifier.

+ The higher than average production cost of MBG from subbituminous coal, delivered at \$25.00/ton, is \$7.40/MMBtu. This reflects a 15-percent cost of capital, a 70-percent load factor, and a process retrofit equivalent to 20 percent of the cost of the gasifier.

NOTE: For MBG production, a \$1.00/MMBtu increase in the price of coal will increase the production cost of MBG by \$1.20/MMBtu.

4

APPLICATION OF SCREENS: THREE CASE STUDIES

In the previous chapters, we developed two screening procedures: the first matches known synthetic fuel producers to potential users; the second evaluates the feasibility of on-site LBG and MBG development. To illustrate the application of these screening procedures, we present case study analyses for three potential users of synthetic fuel:

1. Hoffman-LaRoche, Inc., Belvidere, New Jersey, plant
2. Tallahassee Electric Department, Purdom Station
3. Houston Lighting & Power Company, Cedar Bayou Station.

For each potential user of synthetic fuel, we have applied the hierarchical screening procedure to identify synthetic fuel producers that could supply the user's requirements. In addition, we have considered the feasibility of on-site development of LBG and/or MBG. The potential users examined in these case studies are sufficiently diverse to permit application of the screens for all of the synthetic fuels that may readily serve as boiler fuel (i.e., LBG, MBG, SNG, shale oil, and coal liquids).

To apply the screening procedure to each potential user of synthetic fuel, we began by compiling information on each potential user. Exhibit 4.a summarizes the information required for applying the screens. These requirements include information on plant design and layout, energy input/output, fuel transportation facilities, and the environment. The data required on potential synthetic fuel producers is contained in the project descriptions in Appendix B.

We describe the application of the screening procedures below.

Exhibit 4.a

REQUIRED CASE STUDY DATA ON PETITIONERS

PETITIONER:FACILITY DESCRIPTION:

- Physical Plant & Equipment:
- Land Use:

ENERGY OUTPUT:ENERGY INPUT:FUEL COMPATIBILITY:

- Natural Gas (SNG):
- #2 Distillate:
- #6 Residual
- Crude Oil:
- MBG:
- LBG:
- Ethanol:
- Methanol:

ENVIRONMENTAL RESTRICTIONS:ACCESS TO TRANSPORTATION:

CASE STUDY #1:
HOFFMAN-LA ROCHE, INC.

Hoffman-LaRoche, Inc. (HLR), incorporated in New Jersey, is a multinational firm that manufactures chemicals, health care products, and pharmaceuticals. In accordance with Section 312(c)(1)(2) of FUA, HLR has filed a petition with ERA requesting an order exempting a proposed cogeneration facility from FUA's prohibitions. The proposed cogeneration facility is to be located at HLR's Belvidere, New Jersey, plant.

To meet anticipated energy requirements stemming from a planned plant expansion, HLR intends to install a 23.3 MW diesel engine and a supplementary waste heat boiler to produce steam. Exhibit 4.b describes additional information on the proposed facility.

From a preliminary analysis of the data on the proposed cogeneration project, we immediately eliminated high and medium Btu gas and ethanol as alternative fuels because of their noncompatibility with the end-use processes. SNG and off-site MBG were eliminated as alternative fuels for the waste heat boiler because there presently is no natural gas pipeline to the Belvidere plant. Moreover, the diesel engine is designed to operate only on residual fuel, which eliminates ethanol, methanol, SNG, and MBG as alternative fuels. However, our analysis indicated a potential for the use of coal liquids, oil shale liquids, and on-site LBG development (for the supplementary waste heat boiler, only).

In conducting this analysis, we ranked the alternative fuels in order of highest to lowest probable use. Refined coal liquids rank first as it may be used as a direct substitute for the diesel fuel used in both the diesel engine and the supplementary waste heat boiler. Although equally suitable, refined shale oil is ranked second because of higher project completion risk. Finally, on-site LBG is ranked third because it can only be used in the supplementary waste heat boiler.

In the following sections, we provide a detailed analysis of the potential use of these alternative fuels employing the screening procedures developed in the preceding chapters. On the basis of our analysis, we identified one or more candidate suppliers of coal liquids and shale oil and found that on-site LBG should be a reasonable alternative.

Exhibit 4.b

CASE STUDY DATA: Hoffman-LaRoche, Inc.

PETITIONER: Hoffman-LaRoche, Inc. (HLR)
Belvidere Plant
Belvidere, New Jersey

FACILITY DESCRIPTION:

Diesel cogeneration and supplementary waste heat boiler.

- Physical Plant & Equipment:

Steam and electricity produced on-site will be used in the manufacture of Vitamin C.

- Land Use:

The plant sits on a 500-acre tract. The land surrounding the plant is zoned for industrial use and considered to be well drained and not flood prone.

ENERGY OUTPUT:

Net electrical output: 23.3 MW. 3 MW will be sold to Jersey Central Light and Power Company.

Steam output: 160,000 lb/hr (225 psig) from the supplementary waste heat boiler.

Hot water output: 291,000 lb/hr (180°F)

ENERGY INPUT:

Engine fuel input: 243.3 MMBtu/hr

Supplementary boiler fuel input: 125 MMBtu/hr

FUEL CAPABILITY:

- Natural Gas (SNG):

Not available. HLR is not served by local distributors or interstate pipelines.

- #2 Distillate:

HLR could use #2 as both diesel and boiler fuel.

- #6 Residual:

HLR intends to use #6 as its primary boiler fuel.

- Crude Oil:

Compatibility is not known. Not likely to be used as a fuel in either system.

- MBG:

MBG cannot be burned in the diesel engine. It can be used as a boiler fuel. There are no MBG plants currently planned in the vicinity of the Belvidere plant. Energy input requirements of the waste heat boiler are too small to achieve sufficient economies of scale needed for on-site MBG development.

- LBG:

LBG can be used as a boiler fuel; potential exists for on-site development.

- Coal Liquids:

Coal liquids can serve as a perfect substitute for #6 residual oil.

- Shale Oil:

Refined shale oil can serve as a suitable substitute for #6 residual oil.

- Methanol:

Not compatible.

- Ethanol:

Not compatible.

ENVIRONMENTAL RESTRICTIONS:

The plant is in an attainment region for all criteria pollutants except ozone. It is located in a Class II prevention of significant deterioration area. Air quality for sulfur oxides, particulates, and nitrogen oxides currently is well within national and New Jersey ambient air quality.

ACCESS TO TRANSPORTATION:

The Belvidere plant is currently served by Penn Central Railroad. Interstates 178 and 180 are within a few miles from the plant via New Jersey state highways. The plant is fronted by the Delaware River; thus, it may be accessible by barge.

Liquid Fuels from Coal

A refined coal liquid is the primary alternative fuel that might be used by HLR. Synthetic crude yields refined derivatives that can serve as a perfect substitute for diesel fuel; significant supplies should be available in the next 5 to 7 years.

Appendix B lists 36 projects that are slated to produce liquid fuel from coal. Of these, 23 projects will produce only methanol, a fuel that would not be compatible with HLR's combustion equipment. Accordingly, we limited our review of projects to the 13 projects that would produce syncrude or other substitutes for oil and its refined products. Application of the screens yield one project, Ashland Oil's Breckenridge project, as a candidate supplier. We describe the application of the screens below.

Project Completion Risk

Of the 13 projects we reviewed, only 8 pass the project completion risk screen. The five projects that failed this screen were excluded because of reported financing difficulties or statements indicating that the projects have been temporarily tabled. The eight that pass the screen include five proposed commercial facilities, two demonstration plants, and one pilot plant. The pilot plant was immediately eliminated because its output will be retained for research. The two demonstration plants (including SRC II in Morgantown, West Virginia) and three of the proposed commercial facilities were eliminated because of limited prospects for obtaining sufficient funding. The two remaining projects are:

1. Ashland Synthetic Fuels, Inc., Breckenridge Project, Breckenridge, KY: 50,000 B/D variety of fuels and distillates - 1988
2. World Energy, Inc., World Energy, Inc. Underground Gasification Project, Great Divide Basin, WY: 1416 B/D light oils and refinable liquids - 1985.

Technology Readiness

World Energy, Inc., plans to employ an indirect liquefaction process involving underground gasification and the Fischer-Tropsch liquefaction process. Because of the unproven status of underground gasification, this project does not pass the screen. Ashland Synthetic

Fuels, Inc., is planning to use the H-Coal direct liquefaction catalytic hydrogenation process developed by Hydrocarbon Research, Inc. To date, the only operational application of this technology has been a pilot plant (600 T/D) that started up in 1980. We recommend that the Ashland project pass this screen.

Fuel Availability

Ashland remains a viable supplier under this screen. The diesel engine and supplementary waste heat boiler, fully loaded and in continuous operation, require approximately 500 B/D. Ashland Synthetic Fuels, Inc., anticipates peak output in 1988 to be 50,000 B/D, an amount that considerably exceeds HLR's requirements.

Transportation Costs

Although Ashland has not yet determined a mode of transporting fuel to its customers, rail or tanker truck should be reasonable options. Given the location of the HLR facility relative to Ashland's production site, transportation costs should not limit Ashland as a feasible supplier.

If transportation costs did prove to be a limiting factor, the transportation cost could probably be reduced through a fuel-swapping arrangement involving one of the major refiners located at Marcus Hook, Pennsylvania. Given that the Belvidere plant is fronted by the Delaware River, fuel can then be delivered by barge to HLR.

Moreover, transportation requirements should be able to be readily accommodated at the HLR site. HLR's plant is accessible by two New Jersey state highways that intersect U.S. Interstates 80 and 78. Currently, the company receives twelve 7000-gallon tank trucks per day, five days per week. The increased fuel requirements anticipated from the cogeneration system are expected to increase fuel deliveries to 16 tanker trucks per day on the same five-day schedule.

In addition, rail tankers may be a viable alternative: HLR is served by Penn Central Railroad via facilities owned by Conrail. A single siding runs into the plant area to the north side of the fuel storage tanks.

In that a refined coal liquid is a perfect substitute for diesel fuel, no additional transportation facilities, other than those described above, should be required.

Cost Competitiveness

Recent cost estimates for direct coal liquefaction range from \$8.20 to \$8.70 per million Btu. Accordingly, depending upon the cost performance of the Ashland project, the price of coal liquid products may fall beneath the cost test ceiling of \$7.40 to \$8 per million Btu. A swapping arrangement that reduced transportation costs would increase the likelihood that coal liquids would be cost competitive. Recognizing that more detailed scrutiny would be required to establish that Ashland's project would be cost competitive, we passed the Ashland project through the cost screen.

Environmental Restrictions

Environmental restrictions pose no limitation on the burning of any coal liquid that HLR might purchase from Ashland Synthetic Fuels, Inc. The HLR facility is located in Air Quality Control Region 151, Northeast Pennsylvania-Upper Delaware Valley. This region is classified as being in attainment for all major pollutants except ozone. Moreover, the plant site is located in a Class II Prevention of Significant Deterioration area.

The state of New Jersey has adopted primary ambient air quality standards identical to the National Ambient Air Quality Standards (NAAQS). Summary data (1978) for ambient concentration of SO₂ and suspended particulates (TSP) are within these standards:

	NAAQS Primary	Actual Concentrations
TSP ($\mu\text{g}/\text{M}^3$)		
Maximum 24 hr concentration	260	120
SO ₂ (ppm)		
Maximum 24 hr concentration	0.14	0.062

Source: HLR, Fuels Decision Report, most recent data obtained from Pennsylvania Department of Environmental Resources.

Supplier/User Compatibility

HLR will not experience any technical problems in switching to a refined coal liquid, as it will have essentially the same chemical composition as No. 6 residual oil. The proposed diesel engine-oil fired supplementary waste heat boiler is compatible with operation on synthetic fuel oils, such as those to be produced by Ashland. Noncoincident load characteristics of the supplier and user are not an issue because the fuel can be placed in storage tanks. Currently, HLR has 1.46 million gallons of storage capacity, which is enough for a 22-day supply.

Liquid Fuels from Oil Shale

Refined shale oil is an alternative fuel of equal quality to refined coal liquids. The majority of oil shale projects described in Appendix B produce only raw shale oil. Relatively few of the projects have on- or off-site refining capability. However, the lack of refining capacity is not considered a limiting factor because it should become available in conjunction with the development of these projects.

Application of the screens indicates that five oil shale projects might supply fuel for HLR. However, to avoid high transportation costs, HLR would probably need to enter a swapping arrangement with a shale oil producer. We describe the application process below.

Project Completion Risk

Of the 28 oil shale projects catalogued in Appendix B, 13 fail to pass this screen. The three primary determinants eliminating these projects are:

1. Litigation and legislative delays barring completion of land acquisition (e.g., Rio Blanco Oil Shale Company is awaiting legislative approval, in Colorado, which will allow it to lease more land needed for mining and off-site waste disposal).
2. Failure or delays in obtaining necessary environmental permits (e.g., Mobil Oil Corporation-Parachute Creek Project has yet to obtain the necessary permits. The circumstances surrounding the delays were not revealed by Company representatives.)

3. Inability to obtain firm commitments for project financing (e.g., Pyramid Minerals, Inc., received DOE funding for a feasibility study only to have it rescinded. The company is considering a public offering of stock; however, it must meet SEC requirements.)

The 15 projects passing this screen are:

1. Chevron Shale Oil Company, Clear Creek Shale Oil Project
2. Cities Services, Parachute Creek
3. Cleveland Cliffs, Pacific Oil Shale Project
4. Equity Oil Company, BX In-Situ Oil Shale Project
5. Gary Refining Corporation
6. Geokinetics, Agency Draw
7. Geokinetics, LOFRECO
8. Magic Circle Energy Corporation, Cottonwood Wash
9. Occidental Oil Shale Corporation, Cathedral Bluffs
10. Oil Shale Corporation, Colony Shale Oil Project
11. Paraho Development Corporation, Paraho-Ute Commercial Oil Shale Facility
12. Phillips Petroleum Company, White River Shale Project
13. Quintana Minerals Corporation, Syntana-Utah Oil Shale Project
14. The Oil Shale Company, Sand Wash
15. Union Oil Energy Mining, Parachute Creek.

Technology Readiness

In Chapter 2, we identified nine technologies that are considered to be commercially acceptable. We use these technologies as the criteria for screening the remaining 15 projects. Two projects, designated solely as upgrading and refining facilities, pass this screen, although their success hinges on the remaining projects' ability to produce raw shale oil or syncrude that would be processed by the refiners. In total, nine projects are planning to employ acceptable conversion technologies. The six projects eliminated are either developing new technologies or are using processes that are not yet acceptable according to the standards discussed in Chapter 2 (such as HYTORT or T3). The remaining projects are:

- Cleveland Cliffs, Pacific Oil Shale Project
- Gary Refining Corporation*
- Occidental Oil Shale Corporation, Cathedral Bluffs
- Oil Shale Corporation, Colony Shale Oil Project
- Paraho Development Corporation, Paraho-Ute Commercial Shale Oil Facility
- Phillips Petroleum Company, White River Shale Project
- Quintana Minerals Corporation, Syntana-Utah Oil Shale Project
- The Oil Shale Company, Sand Wash
- Union Oil Energy Mining, Parachute Creek.

Fuel Availability

Purchase commitments awarded under the Defense Production Act and other similar purchase agreements tied to project financing will limit access to fuels for four of the projects. Accordingly, five projects pass this screen. The projects with projected start of peak output are as follows:

- Cleveland Cliffs, Pacific Oil Shale Project: 1990
- Occidental Oil Shale, Inc., Cathedral Bluffs: 1988
- Paraho Development Corporation, Paraho-Ute Commercial Oil Shale Facility: 1986
- Phillips Petroleum Company, White River Shale Project: 1993
- Quintana Minerals Corporation, Syntana-Utah Oil Shale Project: 1986.

HLR's Fuels Decision Report indicates that the cogeneration system will be operational within 7 years. The projected dates for peak production for the remaining five projects indicates that an alternative fuel from oil shale should be available upon completion of the cogeneration facility.

* This project is solely an upgrading and refining facility.

Transportation Costs

The five remaining projects are all located in Colorado or Utah. If the fuel purchased by HLR is to be delivered directly, transportation costs would probably be a limiting factor. To avert this problem, HLR could arrange a swapping agreement with a refinery convenient to HLR. As is the case with coal liquids, the refiners located in Marcus Hook, Pennsylvania, would appear to be reasonable candidates for such arrangements.

Cost Competitiveness

By negotiating a swapping arrangement, HLR should be able to obtain fuel at a delivered cost within the cost test ceiling ranges of \$7 to \$8 per million Btu.

Environmental Restrictions

Whether HLR burned a fuel oil derived from oil shale or conventionally produced oil obtained by a swapping arrangement, there should be no extraordinary restrictions. As outlined in the discussion pertaining to the use of coal liquids, local air quality is well within primary ambient standards, and environmental restrictions would not impede oil combustion.

Supplier/User Compatibility

HLR's original cogeneration program calls for the use of diesel fuel in both the diesel and supplementary waste heat boiler. Refined shale oil can serve as a perfect substitute; thus, no retrofitting will be required. Noncoincident load factors between HLR and any potential supplier is not an issue as liquid fuels can be stored. HLR has sufficient storage capacity.

On-Site Low Btu Gas from Coal

The design of the diesel engine to be used by HLR precludes the use of LBG. However, about 500 B/D of residual fuel oil are required for the supplementary waste heat boiler. This part of the cogeneration system should be capable of operating on LBG. Therefore, our analysis applies only to the use of LBG as an alternative fuel in

the supplementary waste heat boiler. On the basis of our analysis, we find that on-site development of LBG would be a feasible fuel alternative. We describe this analysis below.

Site Selection and Area Requirements

Adequate transportation facilities are in place at the Belvidere plant to sustain an LBG system. Presently, HLR is served by Penn Central Railroad on a spur track running directly into the plant. Currently, 462 carloads per year of raw materials are processed. Additional coal deliveries should pose no problem.

The waste heat boiler specified by HLR currently has a 125 MMBtu/hr fuel input. To meet this requirement, HLR would need to install at least 5 gasifiers.* Installation of a modular system would require approximately 10 acres, which includes the area allocated to coal storage piles and waste treatment facilities. The plant is located on a 500-acre tract owned by HLR, which is more than adequate space for an LBG facility.

User Compatibility

As previously mentioned, LBG gasifiers will be used to provide fuel only for the supplementary waste heat boiler. Given that the facility has not been constructed, HLR could design a boiler that would be compatible with LBG. Data on waste heat boilers provided by OFC indicate that these boilers can operate on LBG. In addition, the anticipated load factor on HLR's waste heat boiler system is about 90 percent, a level that would support economical production of LBG.

Environmental Restrictions

Coal gasification emits pollutants similar to those from coal combustion. HLR will have to meet the NAAQS described in the previous sections on coal and oil shale liquids. However, in its Fuels Decision Report, HLR indicated that the potential existed for burning coal/oil

* This assumes gasifiers with 660 MMBtu/day capacity are installed in a modular fashion.

mixtures in the diesel engine without being restricted by environmental regulations. Therefore, we see no constraints to producing LBG on-site.

Of greater concern is the disposal of solid waste produced from gasification, which will require additional environmental permits and possibly land for proper disposal. The area surrounding the plant is zoned for general industrial use and is designated as being well drained and not flood prone. This should facilitate the acquisition of any additional land and environmental permits required for solid waste disposal.

Access to Feedstock and Cost Competitiveness

The HLR Belvidere plant is within 500 miles of ample supplies of bituminous and anthracite coals. The proximity to various quality coals should allow HLR to choose from a number of commercially proven gasifiers capable of burning either type of coal, including Wellman-Galusha and Koppers-Totzek.

HLR may be able to use unprocessed gas to operate the supplementary waste heat boiler. The use of unprocessed gas would allow HLR to produce LBG at a cost well below the cost test ceiling of \$7 to \$8 per million Btu. If HLR required clean gas, on-site LBG would be cost competitive as long as LBG production costs were not substantially higher than average projected costs. Given the rural location of the plant and the lack of stringent environmental requirements, we anticipate that HLR would be able to construct and operate an LBG facility at a reasonable cost. Accordingly, on-site LBG should be competitive.

Project Completion Risk

Little risk should be involved with installing a modular system of gasifiers. The primary area of risk would be in obtaining environmental permits for waste disposal.

CASE STUDY #2:
TALLAHASSEE ELECTRIC DEPARTMENT

The Tallahassee Electric Department (TED) is a municipal utility serving nearly 50,000 customers in Tallahassee, Florida, and the immediate vicinity. TED has applied to ERA for a permanent exemption to burn natural gas at its Sam O. Purdom plant under the provisions of Section 312(a)(1)(B) of FEA.

The Purdom plant, located in St. Marks, Florida, is composed of seven steam turbines and two gas combustion turbines. Two of the steam turbines (total capacity 15 MW) were not included in the petition because they are on cold standby. The petition applies to 139 MW of the station's total capacity. We only focused our analysis on the three units with significant capacity factors: PP5, PP6, and PP7; the other four units recently had capacity utilization factors of less than 2 percent. The capacity ratings and in-service dates for these units are as follows: PP5, 25 MW, 1958; PP6, 25 MW, 1961; and PP7, 50 MW, 1966 (see Exhibit 4.c).

On the basis of a preliminary assessment of the data shown in Exhibit 4.d, we narrowed the field of alternative fuels to (in order of highest to lowest probable use):

- High Btu gas from coal
- Liquid fuels from coal
- On-site low Btu gas from coal.

We did not consider methanol and ethanol projects as these fuels would not be compatible with the Purdom boilers. Although MBG is a feasible fuel alternative, no proposed MBG facilities are within 200 miles of the Purdom plant. We also did not apply the full set of screens for on-site MBG as the Purdom fuel requirement is not large enough to support MBG production.

On the basis of our application of the screens to the three fuel possibilities, we identified candidate producers of SNG and liquid fuels from coal that could potentially meet the Purdom plant's fuel requirements. Because of site restrictions, we ruled out on-site LBG as a feasible alternative.

Exhibit 4.c

CAPACITY UTILIZATION AT SAM O. PURDOM PLANT
TALLAHASSEE ELECTRIC DEPARTMENT

Unit Number	Capacity Factor (%)
PP 3	0.14
PP 4	1.70
PP 5	16.86
PP 6	22.00
PP 7	43.84
PPGT 1	0.08
PPGT 2	0.27

SOURCE: Tallahassee Electric Department,
Fuels Decision Report,
Submitted to ERA/DOE, 1980.

Exhibit 4.d

CASE STUDY DATA: Tallahassee Electric Department (TED)

PETITIONER: City of Tallahassee, Florida
Tallahassee Electric Department

FACILITY DESCRIPTION:

TED's Sam O. Purdom plant is located in St. Marks, Florida.

- Physical Plant & Equipment:

One of three power plants owned by TED. This plant has seven steam turbines and two combustion turbines. Two of the steam turbines are on cold standby.

- Land Use:

The plant is located on 42 acres, fronted by the St. Marks River, St. Marks Wildlife Refuge, Seminole Asphalt & Refinery, Murphy Oil Company, and residential areas.

ENERGY OUTPUT:

Net generating capacity: 154 MW

ENERGY INPUT:

18.5 billion Btu/day (0.5 capacity factor & 10,000 Btu/kWh heat rate).

29.6 billion Btu/day (0.8 capacity factor & 10,000 Btu/kWh heat rate).

FUEL COMPATIBILITY:

- Natural Gas (SNG):

Natural gas is currently the primary fuel. SNG can displace it.

- #2 Distillate:

Currently, it is used as a secondary fuel.

- #6 Residual:

Currently, it is used as a secondary fuel.

- Crude Oil:

Compatibility is not known; not likely to be a satisfactory substitute for other fuels.

- MBG:

MBG can be used as an alternative to natural gas.

- LBG:

LBG can be used as an alternative fuel to natural gas. It will require retrofitting of existing boilers.

- Coal Liquids:

Coal liquids can replace #2 or #6 fuel oils as a secondary fuel.

- Shale Oil:

Refined shale oil can replace #2 or #6 fuel oils as a secondary fuel.

- Methanol:

Methanol cannot be used in existing equipment.

- Ethanol:

Ethanol cannot be used in existing equipment.

ENVIRONMENTAL RESTRICTIONS:

TED is allowed to burn natural gas and #6 residual oil with a permitted maximum 1.7% sulfur content; #2 distillate fuel oil is permitted with an 0.4% sulfur content.

ACCESS TO TRANSPORTATION:

The Purdom plant is accessible by barge from the St. Marks River. A rail spur runs within 400 ft of the plant. The plant is also accessible by tanker truck.

High Btu Gas from Coal

High Btu gas was selected as the primary alternative fuel because it is a direct substitute for natural gas. Currently, TED uses natural gas as its primary boiler fuel. Therefore, it has ready access to a gas transmission system. Moreover, high Btu gas has a heat value and chemical composition equivalent to natural gas, eliminating the need to retrofit equipment. Six SNG producers are candidates for producing SNG that would either be purchased directly or through a swapping arrangement by TED.

We describe the application of the screens below.

Project Completion Risk

Twenty-five high Btu gas projects are identified and described in Appendix B. Of these, only 10 pass this screen. Eight projects were eliminated because project sponsors were unable to secure adequate funding. We considered proposed pilot plants and process development units to be unacceptable as potential commercial suppliers.

The projects passing this screen, and their proposed conversion technologies, are listed below.

- American Natural Resources, Great Plains Gasification Project: Lurgi with methanation
- CNG Energy Company, Ohio Valley Synthetic Fuels Project: Texaco with methanation
- Emery Synfuels Associates, Emery Synfuels Project: Lurgi with methanation
- North Alabama Coal Gasification Consortium: Texaco and Koppers-Totzek with methanation
- Northern Natural Gas, Minnekota Project: Lurgi with methanation
- Tenneco Coal Gasification Company, Beach-Wibaux Project: Lurgi with methanation
- Texas Eastern Corporation, Texas Eastern New Mexico Gasification Project: Lurgi with methanation
- Texas Eastern Corporation, Lake DeSmet Gasification Project: Lurgi with methanation
- Texas Gas Synfuels, Tri-State Synfuels Project: Lurgi with methanation
- Texas Gas Transmission, Ken-Tex Project: Lurgi with methanation.

Technology Readiness

No high Btu gas technology has been commercially proven. However, we consider the Texaco and Koppers-Totzek processes acceptable because these technologies have been proven in MBG production. As a result, all 10 of the remaining projects pass this screen. Eight projects will employ the Lurgi/methanation process. The remaining two projects will employ Texaco and Texaco and Koppers-Totzek processes.

Fuel Availability

Operation of units PP5, PP6, and PP7 at capacity utilization factors ranging from 0.5 to 0.8 will require thermal input of 12 to 19.2 billion Btu/day. Four SNG projects are eliminated by this screen as all, or a significant portion of the SNG produced, is committed to specific users. In most cases, participants in these projects are gas pipeline companies that will retain a portion of the output to serve customers on their system. The remaining projects and their available output are listed below.

- American Natural Resources, Great Plains Gasification Project: 41 billion Btu/day
- North Alabama Coal Gasification Consortium: 100 billion Btu/day
- Tenneco Coal Gasification Company, Beach-Wibaux Project: 280 billion Btu/day
- Texas Eastern Corporation, Texas Eastern New Mexico Project: 129 billion Btu/day
- Texas Eastern Corporation, Lake DeSmet Project: 150 billion Btu/day
- Texas Gas Transmission, Ken-Tex Project: 145 billion Btu/day.

Transportation Costs

SNG, a direct substitute for natural gas, can be mixed with natural gas for shipment in existing pipelines. Although the likelihood of TED being a customer of any of the pipelines affiliated with the six remaining projects is remote, TED should still be able to purchase gas (at SNG cost) from one of these suppliers. To purchase SNG, TED could negotiate transmission contracts or swapping

arrangements with one or more of the SNG producers for the delivery of gas to the Purdom plant.

Cost Competitiveness

Cost estimates for the Lurgi/methanation process, employed by five of the six remaining projects, indicate that product SNG will cost between \$3.20 and \$8.20 per million Btu; thus, it should be competitive with unregulated natural gas. The remaining project, North Alabama Coal Gasification Consortium, intends to use Texaco and Koppers-Totzek with methanation. The gasifier has been proven in MBG production; therefore, it should result in cost-competitive SNG.

Supplier/User Compatibility

All six projects pass this screen as SNG is a perfect substitute for natural gas.

Environmental Restrictions

SNG is a clean burning substitute for natural gas. Because natural gas is the primary fuel, there will be no restriction on the use of SNG as the alternative fuel.

Liquid Fuels from Coal

In its Fuels Decision Report, TED indicated the capability of burning No. 6 fuel oil in all the units at the Purdom plant. Given this capability, we investigated the potential for using refined coal liquids as an alternative. Application of the project completion risk and technology readiness screens yields the same results as those obtained in the HLR case study for coal liquids. Two projects appear to be potential suppliers:

1. Ashland Synthetic Fuels, Inc., Breckenridge Project, Kentucky: 50,000 B/D, 1988
2. World Energy Inc., Great Divide Basin, Wyoming: 1416 B/D, 1985.

In the following sections, we evaluate these two projects as potential suppliers to TED.

Fuel Availability

The three units under consideration at the Purdom plant operate at 0.5 to 0.8 capacity factors and will require 952 to 2438 B/D of No. 6 fuel oil. The higher end of this range would significantly exceed the total capacity of World Energy Inc.; thus, it is eliminated as a potential supplier. Ashland, however, projects peak output of 50,000 B/D in 1988, and there are no committed users of this output to date. Therefore, we consider Ashland a potential supplier of fuel to TED.

Transportation Costs

Ashland has not yet specified a mode of transportation for distributing fuel to customers. Tanker truck or rail will be the most likely choices. TED has the capability to receive fuel by rail, truck, or barge. Given the proximity of the Purdom plant (located in the Florida panhandle) to Ashland's production site in Kentucky, transportation cost should not impede use of fuel from the Ashland facility.

However, the petitioner claims that increases in the number of fuel deliveries by any one of these methods will disrupt normal traffic patterns in St. Marks. The available information is not sufficient to evaluate this problem. Therefore, we continue the analysis through the remaining screens, noting that resolution of transportation-related issues would require detailed on-site evaluation to determine its feasibility.

One potential solution that would eliminate traffic congestion and cost concerns would be a fuel-swapping arrangement. The Purdom facility is bordered by a refinery of Murphy Oil Company, a large producer and refiner of crude oil. Murphy Oil Company could be a good candidate for a swapping arrangement.

Environmental Restrictions

No environmental restrictions preclude the use of a refined coal liquid at the Purdom plant. The three generating units under consideration are currently capable of burning No. 6 residual oil with a permitted maximum 1-percent sulfur content. A refined coal liquid purchased to displace residential should meet this requirement.

Cost Competitiveness

As we stated in the discussion pertaining to HLR, Ashland's coal liquid product is expected to have a production cost of \$6.80 to \$8.70 per million Btu. Accordingly, it is uncertain whether the fuel will be competitive with the \$7 to \$8 per million Btu cost test ceiling. Entering a swap arrangement with, for example, Murphy Oil, would improve the probability that Ashland could supply TED at a competitive price.

Supplier/User Compatibility

No problems are associated with this screen. Currently, TED uses No. 6 residual oil as a backup fuel. As a result, storage facilities exist on site. Moreover, no retrofitting is required for the units under consideration to operate on a refined coal liquid.

On-Site Low Btu Gas from Coal

The focus of this case study has been on only three of the seven units at TED's Purdom plant. Combined, these units have a 100 MW nameplate rating with a thermal input requirement ranging from 12 to 19.2 billion Btu/day (assuming a capacity factor of 0.5 to 0.8). Although the fuel requirement is large enough to support economic development of an LBG facility, application of the site selection and area requirement screen eliminated this option. We describe this analysis below.

Site Selection and Area Requirements

The Purdom plant, which is located on 42 acres of land in St. Marks, Florida, is fronted by a river navigable by barge. A rail spur runs to within 400 feet of the plant.

Initially, this area seems suited for coal delivery. However, a more detailed evaluation reduces the potential for on-site LBG. Any coal delivered by barge will require facilities to be located at the current site of the storage tanks used for No. 6 residual oil. The removal of these oil storage tanks will result in the loss of TED's secondary fuel, thus decreasing generation reliability during the construction period.

In addition, TED contends that the increased rail traffic will disrupt the normal flow of traffic in St. Marks. We are unable to evaluate this claim with the information available.

There also appears to be insufficient area at the current site to sustain a modular system of gasifiers required to meet the plant's fuel requirements. Operating at a 0.5-capacity factor, the Purdom plant would require a modular system composed of 15 to 18 gasifiers. At a minimum, such a system would require approximately 15 acres of free space.

CASE STUDY #3: HOUSTON LIGHTING AND POWER COMPANY

Houston Power and Lighting Company (HLP), headquartered in Houston, Texas, is an investor-owned utility serving approximately 1 million residential, commercial, and industrial customers in the Houston area. As of 1979, 90 percent of HLP's generating fuel requirements were met by natural gas. HLP has yet to file for either a temporary or permanent exemption permitting the continued use of natural gas; however, HLP is a good example of a case where OFC could take the initiative in promoting the use of an alternative fuel.

This case study focuses on the potential use of alternative fuels to displace natural gas at only 1 of HLP's 12 power stations: The Cedar Bayou Power Station, located in Bayton, Texas. The facility was selected for this case study based on the following criteria:

- Its location outside the Houston metropolitan area increases the likelihood of available land for on-site production of MBG. It also reduces the constraints imposed by environmental restrictions applicable to emissions in urban areas.
- Operation of one or more baseload generating units with relatively high capacity factors. This ensures a constant demand for fuel in large quantities, making operation of on-site MBG facilities economical.
- Sufficient remaining operating life to support development of an on-site MBG operation.

Data on the Cedar Bayou Power Station are somewhat limited.* Cedar Bayou is comprised of three natural gas-fired steam turbine generators with a nameplate capacity rating of 2100.8 MW. Historically, the station has operated at a 70-percent capacity factor, consuming, on average, about 350 billion Btu per day of natural gas. The oldest of the three units began operation in 1970. Accordingly, the entire plant has a remaining service life of 30 years or more.

The power station is accessible by rail and is within 3 miles of Trinity Bay, which would permit barge deliveries of coal. Data are not available on the Cedar Bayou plant site (e.g., unused land available for MBG development); therefore, in our analysis, we assumed sufficient land is available to permit MBG development (see Exhibit 4.e).

On the basis of a data review, we determined that SNG and on-site MBG represent potential options for fuel supply to Cedar Bayou and restricted the detailed application of the screens to these fuels. We eliminated the other alternatives for the following reasons. Refined coal liquids and shale oil would have potential for use only as secondary fuels. Ethanol and methanol fuels would not be compatible with the boiler. With respect to on-site LBG, the plant's fuel requirements are so great as to make on-site MBG the more sensible option. Finally, no off-site MBG projects are within a 200-mile radius of the plant.

In the following sections, we describe our findings from application of the screening procedures for high Btu gas from coal and on-site medium Btu gas from coal to the Cedar Bayou Power Station.

High Btu Gas from Coal

High Btu gas from coal (SNG) is considered the primary alternative fuel available to HLP. Currently, HLP uses natural gas as its primary fuel and is served by intra-state and interstate pipeline companies. Moreover, SNG

* RCG requested certain data on plant site and plant operating characteristics from HLP. After discussion with HLP and several weeks' passage, we believed it prudent to complete the analysis without the data.

Exhibit 4.e

CASE STUDY DATA: Houston Lighting & Power Co. (HLP)

PETITIONER: Houston Lighting & Power Co.
Houston, Texas

FACILITY DESCRIPTION:

HLP Cedar Bayou Power Station, located in Bayton, Texas.

- Physical Plant & Equipment:

The plant consists of three natural gas steam turbine generators.

- Land Use:

Information is not available. The land is assumed adequate to support MBG development.

ENERGY OUTPUT:

Generating capacity 2100.8 MW.

ENERGY INPUT:

351 billion Btu/day (0.7 capacity factor, 9959 Btu/kWh heat rate).

FUEL COMPATIBILITY:

- Natural Gas (SNG):

Natural gas is currently the primary fuel at Cedar Bayou. SNG would be a perfect substitute and does not require retrofitting.

- #2 Distillate:

It can be burned as a secondary fuel.

- #6 Residual:

It can be burned as a secondary fuel.

- Crude Oil:

Compatibility is not known.

- MBG:

MBG can be used as a primary fuel, requiring little or no retrofitting to existing plant and equipment.

- LBG:

LBG could possibly be used, but load requirements would make it uneconomical.

- Coal Liquids:

Refined liquids with qualities equivalent to #2 distillate could be used as alternative fuels.

- Shale Oil:

Refined shale oil could be used as a substitute for #2 distillate

ENVIRONMENTAL RESTRICTIONS:

The air quality control region in which Cedar Bayou Power Station is located is in attainment status for sulfur oxides, particulates, and nitrogen oxides. The Texas Air Control Board reports that, under PSD requirements for sulfur oxides, substantial emission increases may still occur. The area is classified nonattainment for hydrocarbons.

ACCESS TO TRANSPORTATION:

Cedar Bayou Station appears to be accessible by rail and barge.

is a perfect substitute for natural gas; thus, the two fuels can be mixed and burned without retrofitting the existing natural gas-fired boilers.

The application of the project completion risk and technology readiness screens yield the same results as those obtained in applying these screens in the Tallahassee Electric Department case study. Fifteen of the 25 projects catalogued in Appendix B are eliminated because of insufficient funding. Moreover, pilot plants and process development units are considered to be unacceptable commercial suppliers because of the inherent risks involved with the development of new technologies. The 10 remaining projects are:

1. American Natural Resources, Great Plains Gasification Project
2. CNG Energy Company, Ohio Valley Synthetic Fuels Project
3. Emery Synfuels Associates, Emery Synfuels Project
4. North Alabama Coal Gasification Consortium
5. Northern Natural Gas, Minnekota Project
6. Tenneco Coal Gasification Company, Beach-Wibaux Project
7. Texas Eastern Corporation, Texas Eastern New Mexico
8. Texas Eastern Corporation, Lake DeSmet Gasification Project
9. Texas Gas Synfuels, Tri-State Synfuels Project
10. Texas Gas Transmission, Ken-Tex Project.

In the following sections, we apply the remaining five screens to the projects to evaluate their potential as suppliers of SNG to HLP's Cedar Bayou Power Station.

Fuel Availability

Four projects, Texas Gas Synfuels, Emery Synfuels Associates, Northern Natural Gas, and CNG are eliminated as potential suppliers because all SNG produced is already committed to customers. The remaining six projects, individually, do not have the capacity to meet HLP's fuel input requirement of 350 billion Btu per day.*

* This figure is based on a 0.7-plant capacity factor and 9959 Btu/kWh heat rate.

However, two options are available that will allow HLP to use SNG to meet a portion of all of its fuel requirements.

1. SNG could be purchased from more than one supplier. HLP would have to negotiate swapping arrangements between SNG suppliers and the pipeline companies currently serving the Cedar Bayou Power Station to ensure delivery of natural gas in exchange for SNG.
2. OFC could grant HLP a permanent exemption to use a mixture of SNG and natural gas in accordance with Section 312(d) of FUA.

Transportation Costs

Because SNG can be transported through existing pipelines and comingled with natural gas, transportation costs should not preclude HLP from potential SNG suppliers. Although none of the six remaining SNG producers are located in Texas, interstate pipeline companies are affiliated with five of the six projects. Therefore, HLP could negotiate swapping arrangements between one of the pipelines serving a potential SNG supplier and United Gas Pipelines Company, the interstate pipeline serving HLP.

On-Site Medium Btu Gas from Coal

On-site MBG is considered the second choice as a primary alternative fuel available to HLP. On-site MBG has more inherent risk because of the capital requirements for construction and the increased environmental restrictions imposed on gasification, a process that emits pollutants similar to those present in coal combustion. We describe the application of the screens below.

Site Selection and Area Requirements

We have been unable to collect all of the necessary data on the Cedar Bayou Power Station related to this screen; however, we have made assumptions about the plant's location and physical characteristics. Specifically, we have assumed that at least 20 acres are adjacent to the power station that are currently owned by HLP or that HLP could purchase to construct a large-scale MBG gasification system with appurtenant facilities.

Coal deliveries appear feasible. The power station is located within 3 miles of Trinity Bay, where coal could be delivered by barge and transported to the plant by truck. In addition, the station is accessible by rail.

Supplier/User Compatibility

Supplier/user compatibility would not be an issue concerning use of MBG at Cedar Bayou station. With appropriate adjustment of the fuel-air mixture, MBG yields a higher heating value per unit of fuel-air flow and a higher flame temperature. As a result, unit capacity ratings might actually increase with operation on MBG. At most, only minor retrofitting adjustments to the existing boilers should be required.

In addition, the remaining service of the plant is sufficient to allow efficient use of MBG facilities.

Environmental Restrictions

The air quality control region in which Cedar Bayou Power Station is located is in attainment status for sulfur oxides, particulates, and nitrogen oxides. The Texas Air Control Board reports that, under PSD requirements for sulfur oxides, substantial emission increases may still occur. The area is a nonattainment region for hydrocarbons. Gasification facilities will emit some hydrocarbon pollutants; accordingly, the nonattainment classification could pose problems for locating an MBG facility in this area. With this qualification, we have passed the screen for the MBG project.

Access to Feedstock and Cost Competitiveness

The Cedar Bayou Power Station is located within the maximum allowable distance that coal may be transported from the Central-Southwest coal-producing region. In the average cost case, HLP could purchase lignite from suppliers up to 1280 miles from Cedar Bayou. This distance falls to 326 miles in the higher than average cost case (see Exhibit 3.c). Accordingly, access to coal and transportation cost should not limit on-site development of MBG.

Project Completion Risk

Little or no risk is related to available technology or to the actual construction of a medium Btu gasification system at Cedar Bayou. The two areas most likely to halt project completion involve acquisition of environmental permits and project financing. As mentioned previously, Cedar Bayou is in a nonattainment region for hydrocarbons. Financing requirements could also impede development of an on-site gasification facility. Given the current conditions of high interest rates and unstable capital markets, however, HLP is a financially strong utility and enjoys a healthy regulatory environment in Texas. Accordingly, if development of MBG were seen in the best interest of ratepayers, the Texas regulatory authority would probably provide the rate treatment needed to support the project.

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