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VOLUME II–LITERATURE SURVEY

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for
U.S.DEPARTMENT OF ENERGY
Energy Technology
Fossil Fuel Utilization Division

FUELS QUALITY/PROCESSING STUDY

GULF RESEARCH & DEVELOPMENT COMPANY - FINAL REPORT

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Lewis Research Center
21000 Brookpark Road
Cleveland, Ohio 44135

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Fossil Fuel Utilization Divison
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16. Abstract

The final report consists of four volumes. Volume I, Overview and Results, presents the conclusions the study obtained from its evaluation of the feasible paths from liquid fossil fuel sources to generated electricity. The segments from which these paths were built are the results from the fuel upgrading schemes, on-site treatments, and exhaust gas treatments detailed in the subsequent volumes.

This volume, Volume II, Literature Survey, confirmed the validity of initial assumptions about raw materials choices and relevant upgrading processing options. The literature survey also served to define the on-site (at the turbine location) options for fuel treatment and exhaust gas treatment. The literature survey also contains a substantial compilation of specification and physical property information about liquid fuel products relevant to industrial gas turbines.

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VOLUME II

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I. INTRODUCTION

This literature survey is the second volume of the four volume final report for the INDUSTRIAL GAS TURBINE FUELS QUALITY/PROCESSING STUDY.

This volume defines the information base used in the study. It also presents the reader with a compilation of selected information about currently available fuel quality, fuel upgrading options and on site processing options. The selected information is relevant to economically and environmentally acceptable generation of electricity from fossil fuel liquids by way of industrial gas turbines.

The initial volume presents the study's conclusions. The two volumes subsequent to this volume describe fuel upgrading scheme and on-site processing options intended to improve the fuel or to render the products of combustions environmentally acceptable.

II. SUMMARY

The literature survey of petroleum-derived fuels for gas turbine applications addresses both distillate and residual petroleum-derived fuels. This same survey also defines properties and characteristics of current and near-future petroleum distillate fuel. Unlike shale oils and coal liquids, crude oi produces signficant quantities of residual fuel whose properties frequently require substantial upgrading.

The literature survey for coal liquid products and processes indicates differences between the relevant processes have less impact upon product properties than do the separation steps or other down-stream processing used thus far to produce product samples. Signficant product differences are associated with coal source. Fortunately the differences relate to attributes for which this study plans to evaluate upgrading costs. As a result the differences in coal liquid products disclosed by the literature survey will help define the cost/quality issues to be addressed in subsequent tasks of this project.

The survey for shale oil properties indicates a need to consider qualities of products both from in situ and from surface retorting. Metals content in shale oils will be a problem, perhaps even for distillate-type products. Non-organic elements appear to vary with oil shale source location - even with shale bed depth. The type of retorting process has little impact on these properties. Furthermore, the variability in metals and salt content should be reduced by multi-retort commercial scale operations.

The literature survey for fuel additives deals with reducing the adverse effects of corrosion and ash deposition in a turbine. These result from metals contamination in the fuel delivered to the turbine. The survey shows the fuel transportation system can be a major source of problems dealt with by on-site fuel additives. The additives to be used are influenced not only by contaminant nature and level in the fuel but also by the operating conditions of the turbines at a particular site.

The literature survey for on-site treatment of fuels also deals with techniques for removing small amounts of harmful substances. The techniques include using aqueous extraction (i.e., washing a fuel with water) and such mechanical separation procedures as filtration and centrifugation. Those reported separation methods that exploit fluid density differences usually work for on-site turbine fuel treatment because the fuel is the ligher of the two phases. Such methods will have limited applicability (in their present form) for fuels which are the heavier of two fluid phases.

The literature survey for SO_x control by exhaust gas treatment discloses very little information dealing directly with SO_x removal from industrial gas turbine off gas. The fuels used to date for industrial gas turbines are sufficiently low in sulfur content (for reasons other than exhaust gas SO_x quality requirements) that SO_x problems associated with other fuel usages have not yet shown up for industrial gas turbines. Furthermore, the exhaust gas from an industrial gas turbine contains more oxygen and nitrogen (because of the excess air supplied to the turbine) than does the stack gas from most other fuel combustion processes. Thus, the SO_x cleanup requirement may not occur so frequently. Unfortunately, when SO_x cleanup is needed it may present a more costly problem. Cost would be expected to rise for two reasons. First, for a given fuel consumption, more gas must be treated. Second, for a given sulfur loading in the fuel, the SO_x concentration in the stack gas would be lower to begin with.

The literature survey for SO_x control does, however, identify processes which may be used to estimate costs associated with a possible future SO_x removal problem related to industrial gas turbines.

The literature survey for exhaust gas NO_x control considers NO_x generated from fuel nitrogen as well as NO_x generated from the air-supplied N_2. This survey also examines some turbine-combustor related activities intended to reduce the NO_x emissions problem. The survey describes a variety of processes intended for NO_x removal from stack gases. The survey also identifies processes in development which may perform SO_x and NO_x removal simultaneously. As is the case for SO_x removal, most of the literature about NO_x removal from gases relates to boilers rather than turbines. As is the case with turbines the larger amounts of excess air (300° rather than 20%) may create unique problems. There is about three times the exhaust gas to treat and a much larger amount of air-supplied N_2 from which the combustion process can produce NO_x compounds. The survey notes that a substantial amount of NH_3 (also used in fertilizers) would be consumed by several of the NO_x removal processes.

III. DETAILS

PETROLEUM DERIVED LIQUIDS

INTRODUCTION

Petroleum fuel oils in general fall into the following categories:

1. No. 1 or Kerosene-type distillates which can be vaporized without forming excessive carbonaceous deposits. Even when no vaporizing burner is involved (e.g., high speed diesel engines or gas turbines), No. 1 fuel may be specified where a fuel is required which burns more cleanly than No. 2 or middle distillate.

2. No. 2 or middle distillate which is suitable for atomizing burners, or for diesel engines in industrial and heavy mobile service, or for most industrial gas turbines.

3. Residuals and blends which may require preheating for handling and burning and are used in industrial and large commercial furnaces, in low speed and some medium speed diesel engines, and in some gas turbines.

See Figure 1 for general relationships of viscosity, density, and boiling range.

The flash point and distillation requirements distinguish fuel oils from naphthas, gasolines, crude oils, and other petroleum materials containing more volatile fractions. However, ASTM specification D 2880 has recognized the potential use of these more volatile materials by defining them as "No. 0-GT" grade. D2880 also recognizes a "No. 3-GT" grade which covers distillates or low-ash blends of lower volatility than No. 2, even though such liquids are normally consumed in refineries as cracking stock.

ASTM committees have written separate specifications for fuel oils (D 396), diesel fuel oils (D 975), aviation turbine fuels (D 1655), and gas turbine fuel oils (D 2880). Tables 1 to 4, showing detailed requirements for each of these fuels, are attached. Specification D 396 is the basic fuel definition, D 975 emphasizes cetane number, D 1655 emphasizes thermal stability, controlled volatility, and low freeze point (and covers only a No. 1 and No. 0 grade), and D 2880 stresses the limitations on corrosive trace metals in the fuel. As written, the specifications permit the same fuel to be used in more than one type of equipment so long as it meets the different parameters and indeed, the D 2880 gas turbine fuel of commerce is normally fuel oil, diesel fuel, or occasionally jet fuel.

ASTM specifications are written by committees including fuel producers, equipment manufacturers, users, and any other interested parties. Most federal, military, municipal, and industrial fuel specifications are patterned on the ASTM models, and if up to date, include the same limits shown in the attached tables.

CURRENT DISTILLATES FUELS FOR GAS TURBINES

Surveys on heating oils, diesel fuel oils, and aviation turbine fuels are published annually by Bartlesville Energy Technology Center under a cooperative agreement with the American Petroleum Institute. Summary tables show the characteristics of fuels produced in the United States and tabulated (except for the aviation fuels) according to the areas in which they are marketed. These data provide excellent coverage of the desired fuel properties except for the following:

1. Hydrogen Content

From the following formulas, hydrogen can be calculated with a reported accuracy of 1% for petroleum liquids that contain no sulfur, water, or ash:

$H = K-15S$
where H = percent hydrogen
S = specific gravity at 60°/60° F
K = constant from following table

API GRAVITY	K
0-9	24.50
10-20	25.00
21-30	25.20
31-45	25.45

2. Nitrogen Content

Nitrogen content varies greatly with the source of the oil, being as high as 0.66% by wt. in some California crude oils. The higher boiling fractions of a crude contain higher concentrations of nitrogen, so that the residue boiling over 830°F is about double that of its concentration in the original crude. See Figure 2, relating nitrogen content to boiling range, and Tables 18 and 19 showing nitrogen contents of typical crudes.

In in-house surveys, nitrogen content of No. 1 fuels is of the order of 1 to 10 ppm; of No. 2 fuels is 20 to 130 ppm; of No. 6 fuels is 200 to 800 ppm (0.2 to 0.8% by wt.).

3. Aromatics Type

No. 1 fuels are virgin distillates, and the aromatics content is effectively limited by combustion requirements, at least in the kerosene and jet A grades. Total aromatics of 15 to 18% by volume is typical.

No. 2 fuels vary from virgin "premium" (high cetane) diesel fuels of 35-40 API gravity to blends of minimum API gravity (30°), containing 30 to 50% cracked distillates which may or may not have been hydrogenated. The cracked ingredient in the blend may contain 60 to 80% aromatics, but the finished blend is limited to about 35% aromatics by specification constraints on API gravity and/or cetane number.

Table 20 shows detailed hydrocarbon analyses for five different No. 2 distillate petroleum products, plus supplemental inspection data to indicate the relationship with gravity, distillation, and aniline point. Aromatics content depends on the analytical method used for analysis. Data in Table 20 are based on FIA analysis which has the recognized shortcoming of including a significant number of paraffinic sidechains linked to aromatic rings. The more recent concept of aromaticity expressed as carbon-hydrogen ratio will give somewhat lower numbers.*

4. Heat of Combustion

Heat of combustion is normally calculated from gravity, sulfur, and water and sediment content. (The latter two typically represent an insignificant correction for distillates.) See Table 21. The rule of thumb is 135,000 BTU/gal. gross heat of combustion for kerosene and other No. 1 distillates, and 140,000 BTU for No. 2 distillates but the value for a specific distillate may be above or below these

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* Pillsbury, P. W., Mulik, P. R., Singh, P. P., "Fuel Effects in Recent Combustion Burner Tests of Six Coal Liquids," ASME Paper 79-GT-137, presented in San Diego, CA, March 12, 1979.

figures. Heats of combustion for aviation grades of No. 1 distillates are shown in Tables 16 and 17, ranging from 18,514 to 18,622 BTU/lb., net.

5. Thermal Stability

Thermal stability of aviation grade JP-4 (No. O-GT) and No. 1 distillates is expressed as potential gum and also as pressure drop in the CFR Coker (ASTM D-1660) in Tables 15, 16, and 17. Comprehensive surveys based on JFTOT tests (ASTM D 3241) are not available at present.

Thermal stability of No. 2 distillates is usually measured by weighing the sludge that can be filtered out of a measured quantity of distillate after a period of heating, usually at 210°F. A standardized version of this test, which involves oxygen bubbling through the oil while it is heated, is described in ASTM D2274. Government specification MIL-F-16884G, "Fuel Oil, Diesel, Marine", includes this test with a limiting value of 2.5mg/100ml sludge, maximum. Accelerated stability tests become less reliable as the temperature and rate of acceleration are increased, but ASTM D2274 has official sanction and fair acceptance for distinguishing between acceptable stability (virgin distillates and blends with cracked distillates stabilized by hydrogenation and/or additives) and unacceptable distillates (usually those containing appreciable oxygen, nitrogen, sulfur-containing compounds and/or olefinic ingredients).

6. Trace Metals

Ash-forming elements are usually so low in concentration as to be below the level of detection in petroleum distillates as manufactured. A few exceptions are as follows:

- Distillates that have been caustic-washed, "doctor-treated," or copper-sweetened without adequate after-treatment may contain caustic, lead, or copper, usually in concentrations of 0.5 ppm or less.

- Dispersants or combustion-improvers containing barium, magnesium, manganese, lead, or other elements may be added to the fuel, resulting in concentrations of these metals which may be of the order of 5 or 10 ppm.

Tables 22 and 23 show the typically low metals content of ten different distillates at the refinery.*

Fuel producers generally refuse to guarantee such low metals content, primarily because of possible contamination after the fuel leaves the refinery. For example, marine transportation is likely to introduce traces of salt, and pipelines or other common carriers used for gasoline are likely to introduce traces of lead. Consequently, ASTM specification D2880 for gas turbine fuels recommends that vanadium, sodium plus potassium, calcium, and lead not exceed 0.5 ppm in concentration, but this recommendation is relegated to the Appendix rather than the table of detailed requirements.

In addition to the information in the Appendix of D2880, comprehensive summaries of the problems related to trace metals in gas turbine fuels are presented in ASTM Special Technical Publication 531, "Manual on Requirements, Handling, and Quality Control of Gas Turbine Fuel," American Society for Testing and Materials, Philadelphia, PA 19103, 1972. Table 24, based on one paper from that book, shows the range of contaminant concentrations that

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* Sampling and analysis must be conducted with extreme skill to avoid misleading results based on contamination of the samples themselves; e.g., sodium leached from glass bottles, lead from soldered joints in cans, and calcium from the roll oils used in manufacturing the cans.

can be encountered, but the paper does not specify where in the distribution system the various samples were obtained. The paper is followed by printed discussion by Messrs. J.A. Vincent and D.L. Beers showing data on samples from 4 refineries, 8 distribution terminals representing tanker, barge, pipeline, and truck shipments, and 13 different customer delivery points. These data show that distribution contamination takes place, especially with regard to the lead level, and a more sophisticated and costly distribution system would be required to keep contaminants in No. 2 Fuel down to the order of 0.1 ppm.

Another very pertinent paper from ASTM Special Technical Publication 531 is "Experience with Distillate Fuels in Gas Turbines" by Messrs. R. Del Favero and J.J. Doyle of Consolidated Edison Company of New York. Table 25, comprised of two tables from their publication, shows critical trace metals concentrations in gas turbine fuels received at Con Ed from May to July 1971, plus a summary covering May 1971 through March 1972. Quoting from their publication, "...we have been unable to meet the stringent aircraft engine metals specification, and do not believe fuels meeting that specification can be purchased in New York Harbor. We have, therefore, directed our attention to proper fuel housekeeping, and to preventing acceptance of those occasional obviously contaminated shipments."

In reviewing distillate oil characteristics to select two representing best and worst examples for test work, much depends on the definition of distillate. Jet A, or better yet, Jet B (JP-4) would represent the cleanest burning distillates. At the other end of the scale, the GT-3 fuels would represent the more troublesome distillates, both from the viewpoint of combustion characteristics and also the trace metals content. Four ASME papers report partial data on different GT-3 fuels, giving some impression of fuels in this category. (See Exhibits A-D).

If the definition of distillates is narrowed to only No. 2 Fuel Oils meeting ASTM specifications, the best fuel would be one of the premium diesel fuels with an API gravity of 38-40° API, as shown in Table 20. (The severely hydrotreated fuel with API gravity 41.7 is not considered here since it represents fuel of an uncommon quality).

The lowest quality No. 2 which would still meet ASTM specifications would have the minimum acceptable API gravity (30°), maximum permissible 90% point (640F), and maximum carbon residue content (0.35%, on 10% bottoms). If it also contained 0.5% sulfur or more, plus measurable olefin content, it would probably exhibit poor stability along with the attendant problems of darkening and sludge formation in storage, or in heated parts of the equipment.

Variations among No. 2 Fuels are much narrower than the differences between No. 1 (or No. 0-GT) and No. 3-GT fuels, and the choice of a "best" and "worst" distillate might be more meaningful if not limited to fuels of No. 2 grade.

CURRENT RESIDUAL FUELS FOR GAS TURBINES

As with distillate fuels, the annual surveys on heating oils from Bartlesville Energy Technology Center show the characteristics of residual fuels produced in the United States. Pertinent summary tables from the 1979 surveys are reproduced here as Tables 26 to 29. No. 4 Fuel Oil can be regarded as roughly a 50-50 mixture of refinery residue with distillate, No. 5 as an 80-20 mix, and No. 6 as a 90-10 mix. No. 4 and No. 5 are often blended from No. 2 and No. 6 at a marketing terminal or jobber's plant. The reason for the different grades is to reduce the viscosity and pour point characteristics to suitable levels for different types of equipment while minimizing the use of costly distillate.

Characterization of No. 6 Fuel Oil as a 90-10 mix of petroleum residue and distillate is an oversimplification, of course, since a variety of ingredients may be included. For example, high molecular weight polymers formed as by-products in the manufacture of alkylate (a high octane gasoline component) may be added to the normal residuals. It is important that, as fuel ingredients, the polymers be free from traces of sulfuric acid or hydrofluoric acid used as the alkylation catalyst.

"Decanted oil" is also widely used as an ingredient of residuals. "Decanted oil" represents the by-product polymers formed in a fluid catalytic cracker (FCC unit). Such a unit converts high-boiling vacuum distillates into gasoline-range and heating oil-range distillates. Because the heavy polymer comes from the FCC unit mixed with catalyst fines, it is decanted off of the fines after a period of standing, hence its name. It is extremely aromatic and heavier than water, but it is relatively low in viscosity and is virtually free of vanadium and nickel because it is made from distillate. The "Midwest No. 6" Fuel Oil in Table 31 happens to be practically 100% decanted oil and is distinguished by low gravity, low viscosity, high carbon-hydrogen ratio, and an ash analysis reflecting traces of alumina-silica cracking catalyst.

No data are shown here from the annual BERC survey of diesel fuels, since the S-M (stationary and marine) grade in that report is primarily 2-D fuel rather than the residuals and blends that are widely used for slow-speed diesels in overseas and deep-draft marine practice.

Residual fuels are portions of the crude oil that are not volatilized in distillation. With distillation at atmospheric pressure, this usually includes everything boiling above about 680°F. If the "atmospheric residue" is next distilled under vacuum, the consequent residue will represent everything with a boiling point higher than 950-1050°F, depending on the operating conditions. (The still is not actually operated at such high temperatures because the hydrocarbons would be chemically decomposed, or "cracked." The 950-1050°F represents hypothetical boiling points at atmospheric pressure, calculated from the true temperature and pressure in the vacuum still.) In the quest for greater yields of the more valuable light hydrocarbons, various thermal and catalytic processes have been developed to deliberately decompose the "vacuum distillate," ending up with a small volume of highly cracked residual liquid or even a solid coke. Thus, the yield of residual fuel might range from 50% of the whole crude in a simple topping plant, down to zero in the ultimate gasoline refinery. Geographically, the gasoline refineries are concentrated in North America, with European refineries beginning to follow suit. With the worldwide crude production peaking out, there may well never be need for additional crude distillation capacity, but there is prospect of increasing the world's cracking capacity about 50% to convert a larger portion of the residual into lighter products.

International Petroleum Encyclopedia, 1979 (The Petroleum Publishing Company, P.O. Box 1260, Tulsa, OK 74101) shows the following statistics which quantify the preceding discussion. (See Exhibit E.)

Increased refining severity has the following effects on the quality of residual fuels oils:

1. The ash-forming ingredients in the crude, such as vanadium and nickel, are concentrated into a smaller volume of residual product.

2. Viscosity of the residual is increased, often to the point where undiluted residuals are solid tars at room temperature.

3. The thermally stressed residuals may precipitate filter-plugging solids when diluted with less viscous oils. One hypothesis for this phenomenon is that the residual consists of colloidal, high molecular weight asphaltenes held in a dispersed state by resinous components; a cutter stock dissolves away the resins and allows the colloids to agglomerate. Whatever the explanation, ASTM Test D2781, "Compatibility of Fuel Oil Blends by Spot Test," is useful for predicting troublesome blends.

With the growing emphasis on a clean environment, processes have been developed for desulfurizing residual fuels by hydrogenation. Some processes for partial desulfurization involve vacuum distillation of the residual, followed by desulfurization of the distillate portion and reblending of the purified distillate with the residue. Direct desulfurization of the whole residual is more costly and difficult, but there is need for it and it is being done commercially in a few places. Table 33 shows the sulfur levels and trace metals' content of residuals from Kuwait and Alaskan North Slope crude after desulfurization at various levels of severity.

Aside from the influence of refining procedures on residual fuel quality, the initial crude oil characteristics obviously also have a great effect. Important features here are primarily the wax content, which affects the pour point and filter plugging tendencies; the ash concentration and ash composition, which affect the high temperature corrosion and deposition characteristics; and the sulfur content, which affects low temperature corrosion and emissions characteristics. Ranges of sulfur content and pour point are show in Tables 26 to 30.

With respect to nitrogen content of residual fuel, Tables 18 and 19 show 35 to 40 crudes ranging from 0.004 to 0.66%, and Table 31 shows four finished residuals with nitrogen contents of 0.31 to 0.92%, with the higher sulfur residuals showing higher nitrogen contents, although the relationship is not rigorous.

As a generality, residuals from Venezuelan crudes are high in vanadium (typically 150 ppm but possibly as high as 500 ppm); Middle East crudes yield residuals of about 80 ppm vanadium, and domestic (U.S.) crudes about 10 ppm. Low sulfur crudes such as those from West Africa also tend to be low in vanadium content. Table 31 shows ash content, ash analysis, and other properties of eight different No. 5 and No. 6 Fuel Oils in the United States, which reflect a variety of crudes and refining treatments.

An article in Oil & Gas Journal, August 7, 1972, shows the vanadium, nickel, and other ash-forming ingredients in 278 crudes from various parts of the world. This information is abstracted in Table 32 which shows high and low metals content crudes from various areas. The highest vanadium contents are in the heaviest (lowest API gravity) crudes, and the vanadium exceeds the nickel content. However, Table 31 includes a couple of No. 6 Fuel Oils in which nickel exceeds vanadium.

One study* on 23 U.S. crudes showed 16 oils with the following relationship of ash metals: V>Ni>Cu>U. For 5 of the oils, the order was Ni>V>Cu>U. For the remaining 2 oils Cu was predominant. All of the 16 oils with the first pattern of abundance were from reservoirs of Jurassic age or older, whereas the 5 in which nickel predominated were Jurassic or younger. Since nickel has been shown to have some potential for inhibiting high temperature corrosion by oil-ash,** it is possible that the nickel-vanadium ratio in the oil could have an influence on corrosion results.

The alkaline and alkaline-earth elements associated with crudes and residuals are generally inorganic compounds and thus insoluble in the oil. Although extremely important in high temperature corrosion, it has long been recognized that they can be removed to a great extent by washing or other physical treatment of the oil and are not an intrinsic part of its chemical structure.***

In reviewing residual oil characteristics to select two oils representing best and worst examples for test work, the following choices emerge:

1. The very best would be a heavily hydrogenated residual such as a product of Type IV HDS treatment in Table 33. It might be argued that such an oil should be excluded because it represents advanced technology, used only overseas up to the present time although developed in the United States.

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*Ball, J.S., Wenger, W.J., Hyden, H.J., Horr, C.A., and Myers, A.T., "Metal Content of Crude Petroleums," presented before the Division of Petroleum Chemistry, American Chemical Society, 4/8-13/56.

** Amero, R.C., Rocchini, A.G., Trautman, C.E., "Small-Scale Burner Tests to Investigate Oil-Ash Corrosion," ASME Paper No. 58-GTP-19, presented at the ASME Gas Turbine Power Conference and Exhibit, Washington, D.C., March 2-6, 1958.

*** Buckland, B.O., Sanders, D.G., "Modified Residual Fuel for Gas Turbines," ASME Paper No. 54-A-246, presented at the ASME Winter Annual Meeting, New York, NY, November 28-December 3, 1954.

2. The next best candidate from the viewpoint of high quality would be a virgin atmospheric distillate from a selected low vanadium crude; probably one in which the nickel content exceeded the vanadium content. In Table 31, the "Gulf Coast No. 6-1%S" and the "African No. 6" come closest to these qualifications among the true No. 6 Fuel Oils. Outside of this strict category, the "East Coast No. 5" and the decanted oil ("Midwest No. 6") offer lower metals content.

3. For a typical low quality residual, the obvious candidate is a high vanadium Venezuelan residual which has been made by vacuum distillation followed by visbreaking (a form of thermal cracking). The "Caribbean No. 6" of Table 31 can be viewed as being in this category although other specific examples could no doubt be found in which the vanadium content would exceed 200 ppm and because of higher viscosity, a concentration of sodium as high as 80 ppm might be entrained.

COAL LIQUID PRODUCTS

INTRODUCTION

This survey provides a data base about the properties of these coal liquids. Three representative processes are described in order to clearly identify the samples in terms of process streams and their processing histories. Since no integrated demonstration plant has yet been built for any of these processes, the pilot plants and process development runs in which the samples discussed here were produced may differ from the eventual demonstration plant products. Probably the pilot-vs-demonstration plant differences will be greater in yields of various fractions than in the product properties.

For the purposes of this study we have tried to select coal liquid product fractions from the processes which are all in the same boiling ranges. Those boiling ranges also approximate ranges commonly used in marketing petroleum fuels: naphtha (200-350°F), middle distillate (350-600°F), heavy distillate or gas oil (600-950°F) and residuum (950°F+). Middle distillates are presently the most appropriate boiling range for gas turbine fuels. Although some gas turbines presently burn heavy distillates and residuals, a heavy distillate or residual coal liquid would probably present excessive emissions and combustor overheating problems. Nevertheless, some OEM's may develop the necessary equipment, and data on such coal liquids are included in this survey. Although naphtha fractions would be desirable gas turbine fuels because of their lower nitrogen and aromatics contents and ease of ignition, they will probably, instead, be used as chemicals or gasoline feedstocks for greater value; nevertheless, some naphtha data are included here.

In all three coal liquefaction processes, increasing operating severity (reactor residence time, temperature or hydrogen pressure) increases the yields of the lighter fractions as well as the hydrogen consumption and the capital equipment requirements. Furthermore, increased severity may also result in decreased nitrogen and aromatics content of each boiling range of the products.

Each of these process development projects has included tests of the hydrotreating of coal liquids product subsequent to its removal from the liquefaction process system itself. Such treatment is conventional technology, and can be conducted to remove nitrogen and aromatics to the degree desired. For example, full-range SRC-II product (containing 1.0% nitrogen) was hydrotreated to <0.1% nitrogen by Chevron, and H-Coal and EDS products containing 0.2-0.6% nitrogen have also been shown to respond as effectively to such hydrotreating. The EDS processing system contains a hydrotreater as an integral part of the process (the "solvent hydrogenator" in Figure C1); it hydrotreats coal liquid distillates as they are recycled back to the pulverized coal liquefaction reactor. The liquid withdrawn from this solvent recycle loop at the outlet of the solvent hydrogenator has many of the same characteristics (low nitrogen content, etc.) as SRC-II or H-Coal products which have received subsequent hydrotreating. Apparently there were no appreciable volatile metalo-organic compounds in SRC-II products. Other coal liquids may be expected to be similar in this respect.

Our descriptions of the three coal liquefaction processes and their products also contain references to process development project reports permitting identification of the runs which were the source of the samples described. Most of the hydrotreating studies to date have used full-range (middle plus heavy distillate) coal liquid products as their feed. Although such coal liquid products were successfully upgraded, much milder and less expensive conditions might suffice for upgrading only the middle distillate coal liquids. Product specifications alone are not sufficient. Recycle rates and yields would help for cost vs quality purposes. Gaps in the tables of properties indicate absence of data from the references. The SRC-II, H-Coal and EDS processes are described in the following sections.

A. The SRC-II Process

This process had its origins in the SRC-I process developed by Pittsburg and Midway Coal Mining Company between 1965 and 1975. In the SRC-I process (originally named the Solvent Refined Coal process) (SRC) solvent and hydrogen were reacted with the coal at high temperature and pressure, liquefying the coal. Much of the coal entered the liquid phase, freeing ash. The reactor effluent was filtered to remove ash and after gas-liquid separation, solvent was separated from the liquid phase for recycle, leaving the SRC-I product which solidified when cooled below 200-300°F.

The SRC-II process shown in Figure A1(1) differs in several ways from the SRC-I process. The reactor effluent passes through a separations section which recycles some "product slurry" into the reactor. This recycle of "product slurry" returns ash to the reactor, where it contributes catalytically to the liquefaction of the coal. Recovery of liquid products is via distillation and the vacuum tower bottoms are fed to a gasifier which converts unliquefied coal to hydrogen reactor feed and ash to inert mineral residue.

The SRC-II liquid product samples whose properties are described below were produced at the Ft. Lewis pilot plant. The separations systems at the Demonstration Plant will have a different structure than those at P-99 and Ft. Lewis. There will be three liquid products from the Demonstration Plant and commercial operations, characterized by their boiling ranges, which will generally correspond to the present petroleum products: naphtha, middle distillate fuel oil and a heavy distillate.

In most Ft. Lewis operations through 1979, the "fuel oil" stream in Figure A1 was further separated into middle distillate (MD) and heavy distillate (HD). The cut-point between the naphtha and middle distillate has been 350°F, and between the middle distillate and heavy distillate (HD), 550°F. These are the distillation ranges of the MD and HD fuel oil products whose properties are described below in Table A1. (The upper distillation range of HD has been 950-1000°F.) However, studies are planned for 1980-1982 which may reveal that the product slate would be optimized by shifts of 50-100°F in these cut-points, implying corresponding shifts in the properties of the Demonstration Plant products.

The ranges in the values given in Table A1 indicate the values for products from several bituminous coals, including Pitt Seam, W. Kentucky and Illinois No. 6. The limited variations between these coals did not greatly affect fuel properties; however, effects on product yields were appreciable. Because subbituminous coals contain little ash which catalyses coal liquefaction, such coals result in non-commercial product yields in the SRC-II process and no such product property data are presented here.

The sulfur contents of the middle distillate and heavy distillates are, respectively, 0.2% and 0.47-0.50% (maximum), and their nitrogen contents are close to 1.0% and 1.3%, respectively.

According to the present plans for the SRC-II Demonstration Plant, the Gas Turbine Fuel Product will closely resemble the above middle distillate, although its final boiling point may differ. The other Demonstration Plant Fuel Oil Product will be a Boiler Fuel Oil, which will resemble the heavy distillate, approximating a No. 4 fuel oil except for its nitrogen and aromatics content.

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B. The H-Coal Process

The unique feature of the H-Coal process is the design of the liquefaction reactor.(B1) This vessel operates at 800-900°F and 2,000-3,000 psi, contains suspended liquefaction catalyst particles, and receives a feed of recycled heavy distillate coal liquid, pulverized coal and hydrogen. The entire contents of the reactor are strongly back-mixed. Catalyst is prevented from exiting the reactor by screen baffles; however, these baffles permit exit of coal and ash particles. These baffles contain the catalyst bed in a manner allowing catalyst withdrawal and replacement in fluid suspension. The system is termed an ebulliated bed. The process has been studied in 24 lb/day bench units and a 3 ton/day process development unit (PDU), and a 600 ton/day pilot plant is proposed.

The H-Coal process is represented by Figure B1. It includes flash vapor-liquid separators and atmospheric and vacuum distillation units which produce product streams of light and heavy distillate and a bottom slurry for ash disposal. Some heavy distillate is recycled to the reactor for solvent.

Table B1 shows the effects of processing severity and coal type on the relative yields of the product fractions. Comparing columns A and B, low severity (Column A) maximizes the yield of residual fuel oil, and high severity (Column B) maximizes the yield of lighter distillates. Comparison of Columns D and E shows that at high severity processing conditions, the yields of lighter products are somewhat higher from Wyodak coal that from Illinois No. 6 coal. (Column C lists the yields reported in Ref. 3; conditions were unspecified). Table B1 also reports the increased hydrogen consumption with increased severity.

Table B2 lists the inspections of a number of H-coal products available in the referenced sources. The following are some comments on these samples, referring to their "quality" as reflected by their nitrogen contents. Samples A and B were submitted as the most appropriate products for gas turbines; Sample B was upgraded by hydrogenation independent of the H-Coal units. Samples C and D have lower nitrogen levels, but their low-boiling material may be more likely to be used for chemicals or gasoline. Samples A and E-G are all middle distillates and have approximately the same nitrogen contents, 0.2-0.4%. Samples G and I are heavy distillates and contain 0.7-1.0% nitrogen. Although these data appear consistent, several other citations of inspection data are available in which the nitrogen levels are considerably lower in samples corresponding to the above; a critical review of these inconsistencies is needed.(B6) Comparison of Columns F-I shows that Wyodak coal products contain 30-50% less nitrogen than do the products from Illinois coal. No comparative data were available to indicate whether a middle distillate fraction from high-severity processing would contain less nitrogen than a middle distillate fraction from low severity conditions, given the same coal.

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B2. Oil and Gas Journal, August 30, 1976, p. 52

B3. Private Communication, P.F. Kydd, March 1980.

B4. P. P. Singh et al., ASME Preprint 80-GT-67, presented at the ASME Gas Turbine Division Conference, New Orleans, March 10-13, 1980.

B5. Private Communication, P. F. Kydd, 1976.

B6. Shaw, Henry, Kalfadelis, C.D., Jahnig, C. E., "Evaluation of Methods to Produce Aviation Turbine Fuels from Synthetic Crude Oils, Phase I." GRU-IPEA-75 Exxon Research & Engineering Co., 1979 (AFAPL-TR-75-10, AD-A016456)

C. The Exxon Donor Solvent Process

The essential features of the Exxon Donor Solvent process (EDS) for coal liquefaction are shown in Figure C1 (Ref. C1). The liquefaction reactor receives a feed of pulverized coal, solvent and hydrogen and operates at 800-900°F and 1500-2000 psi, with residence times of 30-60 minutes. It is a simple plug flow reactor, containing no catalyst. Some or all of this distillate is fed to the solvent hydrogenator, where it is catalytically hydrogenated into an active hydrogen donor form, which enables it to liquefy the coal in the liquefaction reactor. Note that liquid products may be withdrawn before or after the hydrogenator. In any event, most of the liquid product has been through the solvent hydrogenator several times.

The EDS process has been studied since 1976 in several units, the largest of which is a one ton/day system usually referred to as the Coal Liquefaction Pilot Plant (CLPP). Many studies have also been done of individual process steps in isolated reactors for hydrogenation, coking, etc., and numerous optional configurations of the process units in Figure C1 have also been studied.

One of these options involves variations in the disposition of the distillation bottoms slurry, containing undissolved coal and coal ash (Fig. C2). Until mid-1979, the plan was to feed this stream to a Flexicoker, producing a coker liquids stream, coke and fuel gas. Hydrogen production would be from gasification of the coke or from reforming of fuel gas from the separations section and the Flexicoker. The coker liquids are included in the tables of properties of various EDS product streams and blends. However, it is unlikely that coker liquids will be a component of EDS fuel oil blend products because an alternative to Flexicoking is being seriously considered, which does not produce coker liquids. This alternative to Flexicoking involves a Texaco gasifier (Fig. C2B) receiving the bottoms slurry as feed and producing hydrogen and inert slag.

Another processing configuration option involves removal of product from the recycling solvent stream (1) at the inlet to the solvent hydrogenator or (2) at its outlet. The former case is represented by solid lines in Figure C1 and by the "r w" product columns in Table C1 (from studies on Illinois No. 6 coal). It is also stated that "these raw products should be representative of those produced by the EDS commercial study design process". This material is also referred to as "multipass spent solvent" (MPSS). However, the properties of product taken from the solvent hydrogenator outlet are also reported; see Table C1, "P/H" or partially hydrogenated product. This P/H solvent contains very little nitrogen (0.03%) as compared to the nitrogen in the raw solvent (0.3%). (For consistency, the terms "middle distillate" and "heavy distillate" are used here for the respective distillate fractions; the EDS reports use several other synonyms which are included in the tables and figures for the reader's convenience in tracing the sources of data quoted here).

The heavy distillate stream is very high in nitrogen (1.4%). Recycling of the heavy distillate stream to the solvent hydrogenator is also an option which Exxon has recently indicated interest in studying, but about which no product data are yet available. The relative yields (as percent of of total liquid product) of naphtha, middle distillate (solvent) and heavy distillate are 37%, 28% and 35%, respectively, for Illinois No. 6 bituminous coal; the yields for Wyodak (Wyoming) subbituminous coal are within three points of the foregoing numbers.(4) Liquids from Illinois coal were reblended into the 350-650°F and 650-1000°F boiling ranges to match the petroleum product ranges commonly used, but the properties of these blends did not differ significantly from those of the original coal liquid fractions. A full range fuel oil was also blended (400-1000°F); as shown in Table C1, it had 0.7% nitrogen and a pour point of 20°F.

The characteristics of EDS coal liquids from Wyodak coal (Wyoming subbituminous) are listed in Table C2. The Wyodak middle distillate has nearly the same nitrogen and hydrogen content as Illinois middle distillate. Wyodak heavy distillate has slightly less nitrogen (0.98%N) and more hydrogen than Illinois heavy distillate (1.3%N). A similar comparison applies to the full range fuel blends from these two coals.

For gas turbine tests of various coal liquids being conducted by Westinghouse and EPRI, an EDS liquid was submitted which was withdrawn from the solvent hydrogenator outlet in a run with Illinois coal. This material had an upper boiling point of 700°F because of the cut-point chosen for the distillation unit upstream from the solvent hydrogenator (Table C3, Column A). However, it produced more smoke and NOx than was expected on the basis of its hydrogen content (9.95%) and nitrogen content (0.08%N). The 650-700°F fraction (comprising 13% of the 0.08%-N sample) was removed from that sample by distillation and the remaining 350-650°F sample contained 10.16% hydrogen and 0.04% nitrogen (Table C3, Column B); the smoke and NOx from this sample did fit the predicted levels. The 650-700°F component was apparently the cause of the excessive emissions from the original solvent hydrogenator product.

The EDS process is still in a state of development. Therefore, it is not now certain which of the samples discussed above will become fuel oil products for gas turbines, nor what their cost will be, although there are several good candidates. This can also be said for SRC-II and H-Coal processes.

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SHALE OIL

INTRODUCTION

A study relating to the near term application of shale oil, coal liquids and petroleum liquids for fuel in industrial gas turbines is underway. The time frame of this fuel usage study permits some useful simplifications. For example, only surface retorting and modified in situ retorting of shale oil are deemed of commercial importance in that time frame. Furthermore, the oil shale resources in the Utah, Wyoming and Colorado area are in the focus of those development activites which appear to have commercial potential in the time period of interest to the study.

The physical and chemical properties data of shale oil are needed in order that one can estimate the processing steps required to convert a large part of the crude shale oil into a liquid fuel useable in industrial gas turbines. The same physical and chemical data can also be used to estimate the consequences (good and bad) of blending shale oil liquids with coal liquids and petroleum liquids in such fuels.

Data gathered about crude shale oils do not address directly many of the inspections and specifications associated with an industrial fuel. In this respect, shale oil data are similar to coal liquids data or petroleum data. One can infer from data about a raw material how a portion of that raw material will behave in a particular application. One can also infer how the raw material or some portion of it will, as a result of processing, behave in a particular application. Typical fuel performance indices (e.g., diesel index, octane number, cetane number, pour point, Reid vapor processes, etc.) are properties measurable for a fuel. Such properties can be estimated only approximately from properties of the crude liquid from which the fuel was derived.

An additional precautionary point about fuel properties evaluation would be appropriate. Some fuel specifications reflect useful emperical correlations between the result of a test procedure and the actual behavior of the fuel as a fuel. Provided a new fuel being evaluated is comparable in chemical structure and compostion with the fuel samples used to develop the emperical correlation, the test results can be accepted with a great deal of confidence. On the other hand, if the tested fuel is dissimilar, then results from emperical tests may need to be viewed with much skepticism.

The dissimilarities between the distribution of chemical structure in petroleum on the one hand and shale oil on the other hand are substantial. Many of the emperical correlations developed for liquid fuels derived from petroleum may not be applicable to liquid fuels derived from shale oils. We are concerned about the applicability of some fuel tests derived from petroleum fuels to fuels derived from shale oils. We also feel that the literature about properties of shale oil from modified in situ retorting is less satisfactory than comparable information for shale oil from surface retorting.

CONCLUSIONS ABOUT SHALE OIL PROPERTY DATA

We have examined a number of compilations of shale oil physical and chemical property data and related commentary. Our examination focused upon shale oils produced by surface retorting and by modified in situ retorting.

The following conclusions are generally true for all shale oils whose data were examined:

1. Recovery of light ends implied by available shale oil inspections is somewhat less than the recovery one should anticipate in commercial practice. This discrepancy reflects the nature of the light ends recovery system associated with current non-commercial or semi-commercial operations. Fortunately, this difference between current results and anticipated commercial scale results probably has negligible impact on the liquid fuels for gas turbine study. The components presently not well recovered in the liquid shale oil are sufficiently volatile that they probably would be distilled away while producing the liquid fuels anticipated by this study.

2. Metals contamination in shale oil may present a more serious problem than metals contamination in coal liquids. Rather than being associated with non-volatile compounds, shale oil metallics seem to occur in organo metallics which show up in the distillation fractions one might wish to use in liquid fuels for gas turbines. Furthermore, some of these metallic substances are serious poisons for many of the catalysts used in processes intended to improve either the yield or the quality of liquid fuels for gas turbines.

3. Although metals contamination in shale oils is low relative to that in most crude petroleums, arsenic is much more prevalent in shale oil than in petroleum crudes. Arsenic is a serious catalyst poison.

4. The distribtuion of yield with distillation temperature appears to be more dependent upon the retorting step than upon the grade of shale retorted. One might hope that retorting operating conditions (a factor now beyond the scope of the study) might be selected to improve yields within desirable distillation ranges.

5. The types of compounds found in shale oils appear little influenced by retorting conditions. Shale oils, as a group, have distinctly different hydrocarbon type distributions than do petroluem oils or coal liquids. The distribution of compound types in shale oil does vary with the distillation temperature of a shale oil fraction. However, for a given distillation range, the compound types are not much influenced by the retort type. The variation of compound type distribution with change in distillation temperature is significantly greater than the variation of compound type distribution with shale grade or retorting conditions. This further emphasizes the similarities of the shale oils one to another.

6. Beyond the time frame of this study, oil shale source and grade might become important. For the purposes of the current study, we have focused upon shale oils from a relatively compact geographic area. Clearly, when long term

future circumstances call for producing from shales at distinctly different geographic locations, it may be found that shale oil grade does become a factor not only in yield and salts content but also in organic compound types.

7. The data about properties of shale oil produced by surface retorting appear adequate for the purposes of this study. Furthermore, the methods whereby these shale oils were retorted from their shales are reasonably similar to the methods anticipated for commercial shale surface retorting. Thus, it seems reasonable to use these present data when this study extrapolates to commercial scale operations of surface retorting.

8. This data situation is less reassuring for shale oils to be produced by modified in situ retorting. This is critical to the study because shale oil produced by modified in situ retorting should be in the feed slate for this study.

The various direct combustion processes for in situ oil shale retorting are basically similar with regard to the reactions that take place, although they differ in geometry and flow configuration. Each uses a batch, fixed-bed retort in which a reaction zone is swept through the bed by a stream of injected gas. This gas contains oxygen to sustain the combustion and inert gases, steam or recycled produced-gas to control it. In contrast to the in situ processes, the surface process retorts are moving-bed, continuous reactors. Various types involve co-current or countercurrent flows, and examples in which the gas sweep is up, down, or horizontal may be found.

Attempts to simulate modified in situ operations by various surface retorting simulations have been made. However, in most instances, the particle size distributions used in the surface simulation significantly differed from that anticipated for the commercial modified in situ operation. To proceed with the study we must, to a large degree, ignore the particle size distribution problem.

COMMENTS ON REFERENCED DOCUMENTS

A very comprehensive overview document[5] is the "Oil Shale Data Book" prepared at GR&DC in conjunction with a subcontract to TRW for a DOE funded study related to development of the Naval Oil Shale Reserves. Tabulations of selected physical properties, distillation data and elemental analyses are presented for several shale oils. Unfortunately, data describing distillation fractions and chemical type analyses were not presented. On the other hand, references in the data book as well as comprehensive process descriptions make this document a most useful source of overall information and perspective.

Additional limited information relevant to properties of simulated in situ retorted shale oil appears in References 2, 3 and 6. Reference 2 contains data showing an effect of shale particle size on shale oil composition. Comparative data clearly suggests that in situ produced shale oil should be less dense, have a lower (7 vs 7.5) C to H ratio, less oxygen, but the same N and S contents. The reference suggests these differences are caused by cracking of retorted oil as it flows out from within big, hot pieces of shale. Reference 3 has detailed tabulations and plots for two surface retorted shale oils and a simulated in situ retorted shale oil. The two surface shale oils are similar but the in situ shale oil has a lower end point temperature, higher analine numbers, lower viscosities and lower sulfur content. Reference 6 concentrates on heat and material balances and retorting rates and not upon shale oil product qualities. Nevertheless, this reference shows the same sort of lower density and lower C/H ratio show in Reference 2. What is missing in the cited references is composition by hydrocarbon type.

The main thrust of data in References 2, 3, 4, 5 and 8 substantiate the conclusion that surface retorted shale oils are remarkably similar. Reference 1 augments the surface retorted shale oil data with some need composition-by-chemical type data. Reference 7 primarily discusses downstream processing, however, a comparison between settled and unsettled surface retorted shale oils clearly indicates that the metallics in shale oil are not associated with a substance (such as ash) which settled out with time.

Reference 4 highlights some subtle differences between shale oil from two different retorts. The author summarizes that "Despite wide variation in the shale grade respectively retorted and the known retort differences, the raw shale oil products appeared to be quite similar both physically and chemically. Comparisons with existing data on Piceance Basin Colorado shale oil from these two processes are also quite similar. The one unexpected difference was the 30°F (-1°C) pour point for the Utah Union "B" oil. Potential economic advantages could exist as far as pipelineability if this anomaly is a naturally occurring phenomenon".

In addition to the pour point differences, an apparently significant difference in arsenic and chloride exists. One might ascribe the observed difference to the type of retort used. However, Reference 8 shows a marked variability in metallic contents for shale oil produced by the same kind of retort. A variability associated with oil shale change could explain the arsenic variability disclosed in Reference 4 and in Reference 8.

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SO_x EXHAUST GAS CLEANUP

INTRODUCTION

Gas turbine exhausts now generally contain less SO_x than the maximum permitted by environmental standards, because the fuel oil is desulfurized during manufacture to minimize turbine corrosion. The current U.S. EPA standard for stationary gas turbines limits the exhaust gas concentration of SO_x to 150 ppm when converted to 15 percent oxygen on a dry basis.[1] This limit corresponds to a sulfur content in the fuel of 0.8% by weight, while the current fuel oil specifications for gas turbines usually limit the sulfur content to less than 0.5%.

Although desulfurization of turbine fuels as currently practiced is sufficient to comply with the exhaust gas SO_x concentration limit of 150 ppm, a few local regulations may require desulfurization of the exhaust gas also. Table I shows the degree of exhaust gas SO_x removal required in such exceptional cases.

A search of the API, NTIS, DOE, EPA, Chemical Abstracts, Engineering Index and U.S. Patent Literature has indicated that with the exception of a patent awarded to Rolls Royce Ltd. of England,[2] there is no reference to turbine exhaust gas SO_x removal. The Rolls Royce process, and the applicability of industrial and utility SO_x removal processes to gas turbine exhausts, are reviewed in this section.

CRITERIA FOR EXHAUST GAS SO_x REMOVAL

The following features distinguish current gas turbine exhausts from industrial and utility stack gases in terms of SO_x removal:

- A large proportion of excess air, containing around 15% oxygen

- A low SO_x concentration, usually less than 150 ppm; and

- Negligible concentration of particulates

Although the excess air and low particulate loading features may remain unchanged, the economics of using turbine fuels producing higher than 150 ppm of SO_x in the exhaust gas may have to be evaluated. The SO_x removal literature survey therefore considers the effect of fuel sulfur quality, as well as that of variations in environmental standards on exhaust gas processing needs. As shown in Table I, for a fuel containing 0.5% sulfur, the maximum level of SO_x removal required for compliance with even the most stringent current regulations would be less than 60%.

SO_x REMOVAL PROCESSES

A schematic diagram of the Rolls Royce process is shown in Figure 1. Sensible heat from the exhaust gas is recovered in the process by heating water for process or space heating. SO_2 is absorbed by recirculating water containing $CaCO_3$, $CaSO_4$ and $MnSO_4$ in the scrubbing chamber. Calcium sulfate is produced as a by-product or waste from this process. There has been no report of a demonstration of the Rolls Royce process, but since the process chemistry is similar to many flue gas desulfurization processes currently being practiced by the utility industry for stack gas cleaning, the process appears to have a chance of being successful in its application to gas turbines.

Flue gas desulfurization processes being used by utilities and industries can be classified as:

- Wet: Throwaway or Regenerable; and
- Dry: Throwaway or Regenerable

Most commercial processes are of the wet-throwaway type. The characteristics of the commercial processes are listed in Table II. The Federal Power Commission has published a comprehensive review of the status of flue gas desulfurization technology in the United States.[3] The report indicates that lime and limestone wet scrubbing processes have become the most common commercial systems because they are comparatively more reliable and less costly than the other types. A major problem with lime/limestone scrubbing is the disposal of the large quantities of sludge produced. Other problems include scaling, plugging, corrosion and erosion of the internals of the scrubber.

Commercial wet-regenerable processes include the following reagents:

- NaOH or Na_2SO_3 -- the Double Alkali process; $CaSO_3/CaSO_4$ by-product
- Dilute H_2SO_4 -- gypsum by-product
- $Na_2SO_3/NaHSO_3$ -- H_2SO_4 or S by-product
- MgO -- H_2SO_4 by-product

Although the regenerable processes do not generally have the waste disposal problems of the throwaway processes, they are more expensive. Recently, dry scrubbing systems which feature simultaneous removal of SO_x and particulates in a reagent spray chamber followed by a fabric filter have commanded considerable interest from utilites and industries. Pilot and full scale tests of the dry scrubbing system featuring lime, soda ash, limestone and similar reactants are being conducted at various power plants.(5) So far,the tests have indicated that with soda ash as the reagent, 48 to 98% removal of SO_2 from 800 to 2800 ppm scrubber inlet concentrations can be achieved.

Advanced SO_x removal processes under development are characterized in Table III. The dry processes among these appear to be especially suitable for gas turbine exhaust gas SO_x removal since they produce less wastes and can be more easily adapted to the modular construction of power plants using gas turbines than the wet processes.

The time frame for commercialization of the SO_x removal processes, originally estimated by the Federal Power Commission and modified in this study by reviewing the current status of utility and industrial applications, is shown in Table IV. The commercialization period for the Rolls Royce process may be set at 1986-88, allowing time for engineering and demonstration. There are at present no published plans for demonstration of this process at any power plant.

Since NO_x formed during combustion in a gas turbine usually exceeds the emission limits set by environmental standards, NO_x removal is more important than SO_x removal from gas turbine exhausts. The U.S. Environmental Protection Agency has concluded from a review of the status of current NO_x control technology that 40 to 70% of NO_x can be removed by exhaust gas treatment processes. Any SO_x removal process that can also simultaneously remove NO_x may be economically suitable for gas turbines. An economic evaluation of the competing SO_x and NO_x removal processes is required to determine optimum combinations suitable for gas turbines.

Several simultaneous NO_x and SO_x removal processes have been tested by utilities and industries in Japan.(7) The following are the highlights of the test results:

- Shell Copper Oxide Process: About 90% of SO_x and up to 70% of NO_x were removed by this dry process. NO_x was removed by adding ammonia to the reactor utilizing the catalytic effect of CuO and product $CuSO_4$. In this process, CuO is regenerated by liberating SO_2 which may be converted to H_2SO_4 or sulfur.

- Activated Carbon Process: 90% of both SO_x and NO_x were removed by adsorption of SO_2 and catalytic decomposition of NO_x in the presence of NH_3. Temperatures higher than 220°C favor NO_x removal efficiency but decrease SO_x removal efficiency.

- Electron Beam Process: About 80% of both SO_x and NO_x were removed in pilot tests. In this process, flue gas at about 100°C is mixed with NH_3 and exposed to electron beam radiation. Fine crystals of ammonium nitrate-sulfate are formed and captured by an electrostatic precipitator.

- Wet Processes: Pilot plant tests of the oxidation reduction process have so far removed up to 80-90% of NO_x with over 95% of SO_2. The reactions involve oxidation of NO to NO_2, absorption of NO_2 and N_2O_3 and conversion of the nitrite by the absorbed SO_2 in the aqueous $CaCO_3$ slurry to produce $(NH_4)_2SO_4$. The process is expensive to operate and involves wastewater treatment problems.

CONCLUSIONS AND RECOMMENDATIONS

- Gas turbine gas SO_x removal is not currently practiced because the fuel oil currently used for gas turbines contains less sulfur than that permitted by environmental SO_2 emission regulations.

- Although current fuel specifications limit sulfur concentrations in the fuel to less than 0.8% sulfur permitted by SO_x emission limits, future synthetic and residual fuel oils may contain higher concentrations of sulfur. The use of such fuels in gas turbines will require exhaust gas SO_x removal.

- With the exception of a patent describing simultaneous heat recovery and SO_x removal by absorption in a slurry containing $CaCO_3$ and $MnSO_4$, there is no reference in the published literature to gas turbine exhaust gas SO_x removal.

- Flue gas desulfurization processes currently being used for treating industrial and utility boiler exhausts may have application for gas turbine exhaust gas cleanup.

- Processes or combinations of processes which can remove both NO_x and SO_x appear to have promise of removing up to 90% of both NO_x and SO_x from exhaust gases.

- An economic evaluation of major SO_x removal processes and combined SO_x and NO_x removal processes should be conducted to determine their applicability to gas turbines. The evaluation should consider a range of sulfur concentrations which would be expected in future synthetic and residual fuel oils.

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APPENDIX I - LITERATURE SUVEY SEGMENTS PREPARED BY
GENERAL ELECTRIC COMPANY
GAS TURBINE DIVISION

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ON-SITE FUEL ADDITIVES

The use of additives, sometimes in conjunction with on-site fuel cleanup, is necessary for gas turbine liquid fuels when they contain significant levels of aggressive trace metal contaminants. Such contaminants, if not removed or inhibited, can cause elevated temperature corrosion in the hot gas path section of the gas turbine.

Trace metal contaminants may be a part of the fuel as produced, as in the case of vanadium in petroleum crude and residual oils, or may be introduced after the fuel leaves the producer, such as salt water contamination during barge or ship transport or contaminant pickup during tank storage. Prevention of the latter type of contamination is certainly a viable approach to corrosion control, and will be considered in another section of this overall study. When a fuel at the gas turbine site contains sodium and/or potassium compounds, there may be a choice of using either inhibition or cleanup--the latter usually being selected as will be discussed later. However, if there is vanadium contamination in excess of the threshold limit, an inhibitor is the only option for protecting today's high temperature gas turbines from the fluxing action of molten vanadium pentoxide. No economically feasible process has yet been found to remove vanadium from heavy residual petroleum fuels. Advanced gas turbines with airfoil metal temperatures below the melting point of vanadium pentoxide are being studied; but, their introduction is several years away.

Both corrosion inhibiting additives and on-site fuel cleanup are covered in the following sections of this document.

In the past, most gas turbines located in the U.S. have not required additives or on-site fuel treatment. The majority of baseload turbines have burned natural gas, while peaking turbines have burned clean distillate fuels. Crude oil applications have generally been limited to overseas operation for pipeline pumping and power generation turbines in the U.S. where residual fuels were selected for their lower price or higher availability. In addition, transportation applications, marine and railroad, have been reported where residual fuels were used.

Recently, with the major changes in the world-wide fuel supply and pricing, there has been increased interest in the application of lower grade fuels in gas turbines, especially in combined cycle operation.

No corrosion or ash deposition control additive developments have been reported for shale or coal-derived liquid fuels. The types of contaminating trace elements have been identified in the several direct liquefaction development studies, but their probable concentration ranges have not been established for the various grades of these future synfuels.

The raw material source, specific processing procedures, and refining operations will determine the types and levels of contaminating trace elements. Some synfuel grades may have significant trace element contaminants which could be different from those in the petroleum equivalents. If this proves to be true, the additives and on-site fuel treatment, successfully applied to petroleum fuels in the past, may not be applicable to synfuels. Modified or new techniques would have to be considered and developed.

A corrosion control additive, in a simplified view, ties up an aggressive combustion product as a dry, high melting point ash. Without the additive, the aggressive product could be molten on the superalloy metal surface in the hot gas path and could flux away the naturally protective oxide film of chromium or aluminum.

The combustion ash from the additive itself comprises the largest fraction of the total ash present in the combustion gases. In applications where the deposition rate and consequent fouling of the turbine is unacceptably high or where the deposited ash is difficult to remove, an ash deposition control additive (ash modifier) may reduce the deposition rate and/or make the deposit easier to remove.

MAGNESIUM ADDITIVES

In current combustion gas turbines where fuels require a vanadium inhibitor, magnesium-based additives are generally used. If significant levels of other critical trace metal contaminants such as sodium are present along with the vanadium, the magnesium may be used in combination with other elements such as silicon or aluminum.

The most recent and comprehensive report on field experience with treated residual and crude oils in gas turbines is the recent EPRI sponsored review of worldwide experience on burning residual and crude oils (Reference 1, see References List on page 15).

Requirements for Inhibiting Vanadium

The maximum vanadium concentration allowed in the fuel before inhibition is required varies slightly among turbine manufacturers, but generally ranges from 0.2 to 0.5 ppm. The suggested maximum value in the ASTM D2880-78 Specification for Gas Turbine Liquid Fuel Oils is 0.5 ppm. In the early history of gas turbine operation, when operating temperatures were lower than today, the ASTM specification allowed 2 ppm of vanadium before inhibition was required. To place these fuel vanadium levels in perspective, vanadium occurs in worldwide crude oil in the 5-50 ppm range with some exceptions at very high levels (Venezuela) and a few at less than 0.5 ppm. Examples of the latter may be found in Indonesia and North Africa. Practically without exception, residual oils have vanadium levels above the threshold limit for inhibition.

The need for corrosion inhibition is apparent when it is considered that the inhibitor suppresses the metal corrosion rates from 0.1 to 1.0 inches per 1000 hrs. down to rates equivalent to normal oxidation.

Mechanism for Magnesium Inhibition of Vanadium

A comprehensive review of the basic mechanisms of high temperature corrosive attack on superalloys appears in the recent book: The Superalloys (Reference 2).

Early work in magnesium inhibition of vanadium-induced hot corrosion stemmed from the successful use of magnesium oxide additive in high vanadium content boiler fuels used in central-station power generation. Magnesium additive development for gas turbines was based on studies of the Mg-O-V system. Several workers studied the effect of each of these elements on the melting point of the combustion ash. They showed that magnesium formed a series of vanadates, the highest melting point vanadate being the orthovanadate. Later work (3,4) showed that sulfur also had to be considered as a basic element of this thermochemical system because sulfur is always present in residual fuel, and, sulfur competes for the magnesium by forming magnesium sulfate. The specific ash composition was found to depend on the concentrations of magnesium and vanadium, the turbine gas and metal temperatures, sulfur dioxide-trioxide pressures. With adequate magnesium in the fuel, the resultant combustion ash is a high melting point dry solid. The chemical composition of the ash is a complex mixture of magnesium vanadates, magnesium sulfate and magnesium oxide. The ratio of magnesium oxide to magnesium sulfate will vary with ash deposition temperature and sulfur level in the fuel.

Several workers (5) have concluded that the excess magnesium required above the stoichiometric ratio to react with vanadium results in a dry inert ash which dilutes potentially aggressive species.

Types of Magnesium Additives

Magnesium additives used for vanadium inhibition vary in chemical composition and physical properties. Broadly they can be classified as oil-dispersable solids, oil-soluble liquids and water soluble compounds.

Oil-dispersable magnesium solids successfully used as inhibitors have been magnesium oxide suspensions or to a lesser extent, magnesium hydroxide suspensions. The magnesium oxide oil-dispersable suspensions were developed from "fireside" additives used with high vanadium content residual fuels in boilers. The magnesium oxide additives used in gas turbines have had finer particle size and lower contaminant levels (sodium, potassium and calcium) than the "fireside" additives. Due to the tendency of the solid additive particles to settle, these additives are usually injected into the fuel on-line during turbine operation.

Oil-soluble magnesium additives reported include magnesium napththenate and overbased magnesium sulfonate. The naphthenate is truly completely oil soluble and was used in early turbine applications where it was felt desirable or necessary to pre-inhibit a large quantity of fuel and store it. The naphthenate has an intrinsic low magnesium content and a high price based on units of magnesium. The overbased magnesium sulfonates have a higher magnesium content and are being fairly widely used. They form clear, uniform storable mixtures in the fuels, but they are not truly oil soluble. Part of the magnesium is present as magnesium sulfonate, an oil soluble metallo-organic compound, while the remainder of the magnesium is present as colloidal inorganic particles such as magnesium carbonate. This mixture has a higher magnesium content than the true metallo-organics. (Similar additives are widely used in automotive crankcase lubricating oils).

Water-soluble additives suggested have included magnesium sulfate, magnesium acetate and magnesium chloride. Only the sulfate has been applied as an inhibitor in gas turbines. Magnesium sulfate may be the most economical in price per unit of magnesium. Its use has been limited to a few installations due to handling difficulties. It must be dissolved in pure water, and the water solution injected and uniformly dispersed in the fuel.

Magnesium Additive Dosage Rates

Theoretically and under ideal conditions, the magnesium/vanadium atom ratio required to form the high melting point orthovanadate should be 3/2, or the weight ratio should be 0.72/1. The experiences of several investigators in the field using test rigs have shown that a minimum 3/1 weight ratio was actually necessary to prevent hot corrosion during combustion of residual fuels. Practically all of the gas turbines in use today use this minimum 3/1 weight ratio of magnesium/vanadium. For a fuel where sodium is also present and the sodium/vanadium ratio is high, the magnesium/vanadium weight ratio has been much higher than 3/1. This generally occurs in low vanadium content fuels, but where the vanadium level still exceeds the threshold level (for example, 0.5 ppm).

Additive Performance

The performance of the various types of magnesium additives has been compared by several investigators. (5) Some of the early tests were carried out in turbines with much lower firing temperatures than today's turbines so that the results may not be directly applicable. The general conclusion appears to be that the three general classes of magnesium additives perform equally well as vanadium corrosion inhibitors when they are compared at the same magnesium/vanadium ratio.

Because magnesium is used at a typical magnesium/vanadium ratio of 3/1, magnesium compounds make up the bulk of the combustion ash, a fraction of which accumulates in the turbine hot gas path. Deposit buildup on stator and rotor airfoils can degrade turbine performance requiring cleaning at intervals to restore performance. (6)

There are three techniques used for turbine cleaning; any or all of which may be employed on the same machine. The three techniques are nutshell injection under load, automatic deposit shedding by shutdown, and shutdown plus water washing. The length of continuous operation without a shutdown and/or washing/cleaning cycle, will depend on the gas turbine, its operating conditions, and the quality of the treated fuel.. In addition, as the ash deposits build up, the restriction of flow through the first-stage nozzle causes the compressor discharge pressure to build up to a point where compressor surge and possible stall will occur. Generally the operating period attained to date in commercial service, before a shutdown and/or washing/cleaning cycle has been required, has been between 150 and 1500 hours. This covered the spectrum of fuels from the highest ash residual to the lower ash crudes. It is possible that more selective fuels or treatments would permit longer continuous operation.

Deposit modifiers have been used to reduce the deposition rate and/or to make the deposits more friable. The most commonly used ash modifier is silicon, and its use will be discussed in the section on silicon additives.

The effect of the chemical and physical form of the magnesium additive on the nature of the deposited combustion ash is not clear although some early performance data on older turbines with the lower turbine inlet temperatures of that era indicated a measurable difference in deposition rates. (5) It is felt that the ash depositon is considerably influenced by the turbine design and the operating conditions.

SILICON ADDITIVES

Silicon-based additives have been used in gas turbines burning ash-forming fuels both for combustion ash deposition control and for high temperature corrosion inhibition. The high temperature corrosion inhibition has included both sodium sulfidation and vanadium corrosion. The types of silicon products used included organo-silicon compounds, silica (silicon dioxide) and mineral silicates. In many of the applications, silicon has been used in combination with magnesium, especially at the higher turbine firing temperatures.

Requirements for Silicon Additive Application

Because silicon additives have been used alone or in combination with magnesium and have been used for ash deposition control as well as high temperature corrosion control, the criteria for silicon additive application are more complex than those for the application of magnesium additives to control vanadium corrosion. Among the critical factors are:

a) Turbine inlet temperature
b) Turbine design
c) Sodium (alkali metal) level in fuel
d) Vanadium level in fuel
e) Other contaminant fources

The selection of hot gas path materials, including corrosion resistant coatings, the cooling provided for the hot gas path components and the turbine inlet temperature, will affect the trace metal contaminant level the turbine can tolerate. In addition to fuel contamination, alkali metal (sodium and potassium) contamination can occur in the turbine inlet air and in any water (steam) injected into the combustor for NOx control. It is the sum of the alkali metal contamination from all of these sources which must be taken into account when considering the application of a silicon additive. Also, the rate of ash deposition using a silicon additive will be influenced by the gas temperature, metal surface temperature and configuration of the hot gas path section of the turbine.

Table 1.1-1 is a matrix showing which additive or additive combinations have been used in gas turbine applications at different turbine inlet temperatures, sodium concentration ranges, and vanadium concentration ranges.

Silicon alone has been successfully used at turbine inlet temperatures less than 1400°F (760°C) with quite a wide range of sodium and vanadium concentrations. Low ash deposition rates and low corrosion rates were generally reported in these applications.

Silicon in combination with magnesium was used in the 1200-1600°F (650-870°C) turbine inlet temperature range over a wide range of sodium and vanadium concentrations. Low deposition rates and low corrosion were typical in this experience.

In the turbine inlet temperature range of 1600-1950°F (870-1065°C), magnesium alone has been used in the reported field applications. In these cases the sodium level in the fuel was reduced to 1 ppm maximum by fuel washing before inhibition. The magnesium/vanadium weight ratio was 3/1 in these applications. Trial runs with silicon-magnesium combination additives at these high turbine inlet temperatures in one manufacturer's turbine showed no significant decrease in ash deposition rate while using silicon, but the deposited ash was more friable.

Mechanism of Silicon Corrosion and Ash Deposition Control

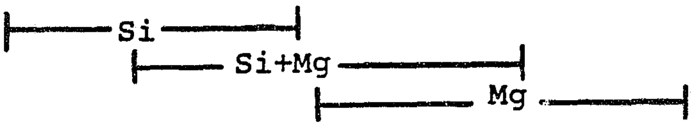
In the turbine inlet temperature regime (1200-1400°F) where silicon additives alone have been successfully used with sodium and sodium-vanadium contaminated fuels, the mechanism of corrosion control is not clear. Silicon additives form a high melting point oil ash which does not deposit readily on metal surfaces, and the ash which does deposit does not readily corrode the metal surfaces. Some investigators (7,8) have attributed the

Table 1.1-1

Gas Turbine Operating Experience
With Silicon and Magnesium Additives

FUEL CONTAMINATION		TURBINE INLET GAS TEMPERATURE,°F			
VANADIUM, PPM	SODIUM, PPM	≤1200	1200-1400	1400-1600	1600-1950
<0.5	<0.5				
	0.5-2	Si			
	>2		Si		
0.5-10	<0.5			Si+Mg	
	0.5-2		Si	Mg*	Mg*
	>2	Si	Si,Si+Mg	Si+Mg	
>10	<0.5				Mg
	0.5-2	Si		Si+Mg,Mg	Mg*
	>2	Si	Si		

TEMPERATURE
RANGE
OF
APPLICATION



*Washed to less than 1ppm of sodium

corrosion control to a simple dilution of the potentially aggressive species by the voluminous, porous dry silica component of the oil ash. On the other hand, in the case of sodium, the porous ash layer may allow penetration of oxygen from the combustion gas into the metal oxide layer under the deposit and prevent the formation of the metal sulfides, thereby arresting sulfidation attack.

The action of combined silicon-magnesium additives in the 1200-1600°F turbine inlet temperature range where they have been used with vanadium-sodium contaminated fuels is also not fully understood. Silicon does not form any Si-V compounds. Silicon does form some magnesium silicate at these temperatures although most of the silicon appears as silica (silicon dioxide) in the fuel ash. In the combined silicon-magnesium combinations, magnesium appears to retain its role in tying up the vanadium as high melting point vanadates while the silicon may act as a diluent to form a dry ash with the sodium-bearing ash components. At high sodium levels, the thermochemistry is further complicated by the Na-O-V system. Silicon used in combination with magnesium in this temperature range does reduce the ash deposition rate and forms friable deposits which are easy to remove.

In the 1600-1950°F turbine inlet temperature range, silicon in combination with magnesium has not been reported in operational turbine use. Some limited experiments in this temperature regime indicated that the addition of silicon to magnesium did not decrease the rate of ash deposition although it did modify the ash deposit so that it was more friable and easier to remove by a nutshelling cleaning procedure. In these high temperature tests, the sodium was removed by desalting to 2 ppm or less by fuel pretreatment to prevent high temperature sulfidation attack.

Types of Silicon Additives

Silicon additives used in gas turbine fuels have been oil-soluble organo-silicon compounds such as tetraethyl silicate or oil-dispersable suspensions of finely-divided silica (silicon dioxide). Silicates of aluminum and magnesium have been tried, and these are discussed in Section 1.1.3, Other Additives.

The organo-metallic silicon additives are probably more effective in forming the desired fine, soft, porous silica particles during fuel combustion.

Oil dispersions of fine silica particles are less expensive but they must have fine enough particle sizes so that they do not cause abrasive wear in fuel system components. Ultra-fine "fume" silica dispersions are too expensive for gas turbine additive applications.

Dosage Rates of Silicon Additives

Where silicon additives have been used by themselves in the lower turbine inlet temperature ranges for ash deposition and corrosion control, the dosage rate has been based on the fuel ash content. The ratio of SiO_2/fuel ash has typically ranged for 0.5/1 to 2.5/1.

The dosage rates of the combined silicon-magnesium additive have varied with sodium and vanadium contaminant levels and with turbine inlet temperature. Based on one turbine manufacturer's experience, (9) the following are examples of the dosage rates recommended for two different turbine metal temperatures. The turbine inlet temperature corresponding to these metal temperatures depends on turbine design, metal cooling provided and aerodynamics.

Turbine Metal Temp-F(C)	V/Na Wt. Ratio	(Mg+Si)/V Wt. Ratio
1300 (705)	0.5	7
	10	4
	1000	3
1500 (815)	0.5	9
	10	5
	1000	3.5

The relative amounts of magnesium and silicon in the (Mg+Si)/V ratio were not given although in general the Mg/V would be 3/1 or somewhat less. The quantity of silicon required for the desired protection action increases as the level of sodium in the fuel increases. At some point, it is more economical to remove the salt from the fuel than to add large amounts of silicon additive. One turbine manufacturer (10) based on operating experience set the maximum sodium in the fuel at 5 to 6 ppm for silicon inhibition alone.

Gas Turbine Operating Experience with Silicon Additives

A. Distillate Fuels

Corrosion and ash deposition control additives have not been widely used with distillate grade fuels, but one experience has been reported where a silicon additive reduced corrosion caused by a heavy distillate fuel subject to salt water and residual fuel (vanadium) contamination.

B. Crude Oil

Most operating experience with silicon additives has been with crude oil fuels used mainly in the Mid-East. (9,10,11,12)

In one reported application at 1350°F turbine inlet temperature, use of an organic silicon additive permitted up to 10,000 hrs. of operation before turbine ash buildup reduced the turbine power output by 10%. Low corrosion rates were also reported. The fuel used had average contaminant levels of 5 ppm of sodium and 5 ppm of vanadium.

At turbine inlet temperatures in the 1400-1600°F range, magnesium-silicon combination additives have been required. This has also been the case below 1400°F when the sodium and vanadium levels were high. Experience with combined magnesium-silicon additives has covered a turbine inlet temperature range of 1200 to 1470°F, a total ash range of 20 ppm to 400 ppm and a sulfur level range of 0.1 to 3%. Because silicon requirements increase with increasing sodium levels, fuels have been washed when the sodium exceeded 5-6 ppm to avoid high additive costs. In these applications of magnesium-silicon additives, hot corrosion rates have been low and fouling rates were typically reduced by a factor of 2 to 5 compared to magnesium alone.

No crude oil gas turbine experience was found above 1500°F turbine inlet temperature where silicon additives were used.

C. Residual Oils

Gas turbine experience has been reported (5,9) using silicon and silicon-magnesium additives in residual oils at the lower turbine inlet temperature ranges (below 1400°F) for corrosion and deposition control. This experience involved a few older machines operating in Europe. At higher turbine inlet temperatures (1600-1950°F) no residual fuel machines have been reported operating with silicon additives alone. In this higher temperature regime fuel washing is used to remove most of the sodium, and magnesium alone is used as the vanadium inhibitor.

Successful residual fuel operation with silicon additive alone has been reported at 1150°F turbine inlet temperature with a fuel having 140-350 ppm ash, 10-60 ppm vanadium and 20-60 ppm of sodium. Turbine washing intervals of 2000 hrs. were possible with the silicon additive.

At 1300°F turbine inlet temperature, a European application required magnesium at a 3/1 weight ratio of Mg/V to prevent corrosion. The typical vanadium level in the fuel was 75 ppm, and the sodium was reduced to less than 10 ppm by fuel washing. Silicon additive was used in addition to the magnesium for ash deposition control. The dosage of silicon was not reported, but the presence of silicon afforded a 400 hr. operating interval between turbine washings. Without silicon, the interval would have been much shorter.

No gas turbines have been reported operating regularly with silicon-magnesium additives in 1600-1950°F turbine inlet temperature range. Two field tests of about 200 hr. duration in the 1750-1850°F temperature range showed little if any reduction of ash deposition rate even with large concentrations of silicon. (Si/Mg/V weight relationship of 7/3/1). The deposits were more friable when silicon was used making them more amenable to removal by nutshelling, but their water washability was not improved. Contaminant levels in the fuels used were 70-100 ppm of vanadium and less than 1 ppm of sodium, the latter controlled by on-site fuel washing. These tests included heat recovery steam generators (HRSG) following the gas turbines. The presence of silicon appeared to increase the ash deposition rate in the HRSG even though the ash was much softer when silicon was used. The addition of silicon increased the total combustion ash by a factor of about 1.7.

The lack of response (reduction) of turbine ash fouling rate when silicon was added to magnesium in residual fuel gas turbines at these high firing temperatures may be tied to the sodium level. There is some evidence from turbine tests that silicon may reduce the fouling rate when the sodium level is greater than 2 ppm, but has little effect when the sodium level is less than 1 ppm.

OTHER ADDITIVES

In the extensive research and development on hot corrosion control, many elements have been found effective in reducing hot corrosion. The scope of this report has been limited to those additives which have been reduced to practice and have been used in commercial gas turbines. Many additives have not been reduced to practice for any of several reasons: price, availability, effect on fuel hardware, formation of toxic effluents, and formation of turbine deposits not readily removed from the turbine by practical cleaning techniques such as water washing.

Calcium Additives

The ability to inhibit vanadium corrosion by formation of vandates is a generic property of the alkaline earth family of elements, i.e., magnesium, calcium (19), barium (18,19) and strontium.

Calcium was one of the earliest vanadium inhibitors tried in gas turbines because of its low cost and high availability. It proved very effective as a corrosion inhibitor, but it formed combustion ash deposits at a much higher rate than did magnesium additives. Because the dosage rate is based on the atom ratio of the inhibiting element-to-vanadium, the calcium weight ratio requirement was about 70% greater than with magnesium. This would be a 5/1 weight ratio of Ca/V compared to 3/1 for Mg/V.

The mechanism for calcium inhibition of vanadium corrosion is analogous to magnesium; the Ca-O-V-S system being similar to the Mg-O-V-S system.

Calcium is not being used in operational gas turbines today because of the high ash deposition rate.

Aluminum Additives

Aluminum has been used in place of silicon as an ash modifier in combined aluminum-magnesium additives. (13) In turbine trials at 1400-1500°F turbine inlet temperature, aluminum reduced ash deposition rates with treated residual fuel (85 ppm vanadium) by a factor of about four. However, to attain this improvement, the aluminum/magnesium weight ratio had to be greater than 1/1. The high cost of oil-dispensable or oil-soluble aluminum additives which would not degrade fuel system components (pumps, flow dividers and check valves) has discouraged development of aluminum additives.

A combination magnesium-aluminum-silicon additive was developed for boilers and gas turbines firing residual fuel, but no gas turbine applications have been reported. (14)

Chromium Additives

Chromium oxide was recognized as an inhibitor for sodium sulfate corrosion as early as 1952. (15) The goal at that time was to use an inhibitor for raw (unwashed) residual fuels as an alternative to washing the fuels at the turbine site. Although it was successful as a corrosion inhibitor, it was never used commercially due to the high cost, the corrosive nature of the by-products to exhaust ducts, and the possibility of toxic exhaust emissions.

More recently, chromium additives have been used for distillate fuels with low contamination levels of sodium. The emissions of chromium compounds resulting from the low dosage rates recommended should be within acceptable limits.

Recently, combined chromium-magnesium additives have been offered to the industry for application as sodium-vanadium inhibitors at the 1600°F metal temperature level. (16) They are claimed to be effective with combinations of vanadium from 0.5 to 10 ppm and/or sodium plus potassium from 0.5 to 10 ppm. A variation of this additive also contains silicon. No actual turbine experience on this class of additive has been reported.

Nickel as an Inhibitor

Nickel can inhibit vanadium hot corrosion because it forms a series of vanadates analogous to magnesium vanadates. (19) Nickel is not added to residual or crude oils, but the nickel which occurs in varying ratios with vanadium in crudes can inhibit part of the vanadium present.

Natural Minerals

Certain minerals contain Si-Al-Mg in various combinations which could conceivably qualify them as corrosion control and ash deposition modifiers. (5, 17)

Kaolin is a hydrated aluminum silicate which proved to be an effective corrosion inhibitor in laboratory tests. At about 1500°F, Kaolin ties up sodium as sodium aluminum silicate. Kaolin was tested in a gas turbine (unpublished data) at 1450°F turbine inlet temperature in combination with magnesium oxide and with barium carbonate. The fuel used was a raw (unwashed) high vanadium residual oil. Both the combination with magnesium oxide and with barium carbonate gave high ash fouling rates, and the deposits were difficult to wash from the metal surfaces.

Talc is a natural magnesium silicate which has had some limited application for boiler deposit control. It is attractive as a potential inexpensive substitute for oil-soluble silicon-magnesium additives. No turbine experience has been reported to date with talc although one foreign application is planned.

SUMMARY: INHIBITORS FOR CORROSION AND ASH DEPOSITION CONTROL

Gas Turbine experience with corrosion and ash deposition control additives in contaminated liquid petroleum fuels can be summarized as follows:

- For sodium contaminated fuels, fuel washing has been preferred over inhibition wherever potable water was available.

- Some sodium-contaminated fuels have been successfully inhibited for low turbine inlet temperatures with silicon additives. Silicon also greatly reduced ash deposition rates in these applications. Chromium compounds have been used to some extent at higher turbine inlet temperatures to inhibit fuels with low sodium levels but still above the threshold levels.

- Residual oils, crude oils and contaminated distillate oils containing vanadium and sodium have been successfully treated with silicon additives for corrosion and ash deposition control at low turbine inlet temperatures.

- The above vanadium-bearing oils used at intermediate turbine inlet temperatures have required magnesium additives to prevent hot corrosion. The addition of silicon along with magnesium in this temperature regime also controlled sodium corrosion although desalting the fuel to about 5 ppm maximum sodium content was also recommended to avoid excessive silicon requirements. Silicon-magnesium combinations at intermediate turbine inlet temperatures also significantly reduced turbine ash deposition rates.

- In the high turbine inlet temperature range, sodium was always reduced to 1 ppm or less by fuel washing, and magnesium compounds were used to inhibit vanadium corrosion. In limited trials with silicon-magnesium additives in washed fuels, the presence of silicon did not significantly reduce turbine ash deposition rates although it did modify the physical structure of the ash.

- The additives being currently used with vanadium-bearing residual fuels effectively control hot corrosion. However turbine operators cite turbine ash deposition rate and ash removal as areas where improvement is needed.

- Chemical compounds of elements other than magnesium, silicon and chromium have been demonstrated to be inhibitors for hot corrosion, but they have not been reduced to practice as commercial additives. A common problem among many of these possible alternative compounds is high turbine ash deposition rates and/or tenacious deposits.

The possible application of corrosion and ash deposition control additives to future synfuels derived directly from coal or shale is an open question. If such fuels are upgraded and distilled, they may be free of contaminants, except foreign materials picked up in transportation and handling. On the other hand, raw fuels from direct synfuels processes could contain ash-forming components, and these components could be different from those in petroleum fuels. Raw shale oils can contain iron and arsenic. Raw coal liquefaction fuels can contain silicon, iron, aluminum, titanium, potassium and sodium. If such substances were present in a gas turbine fuels, new additives may have to be developed for corrosion and ash deposition control.

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ON-SITE FUEL TREATMENTS

POSSIBLE FUEL CONTAMINANTS FOR ON-SITE REMOVAL

Petroleum distillate fuels as produced are clean and free of contaminants deleterious to gas turbine operation. However, between the refinery and the gas turbine system there are potential sources of such contaminants. Salt-laden water is the contaminant of concern both on account of its prevalence and its potential effect on the gas turbine. Sodium salt is the main component of the salt-laden water; potassium salt being present in far lower concentrations. Other contaminants commonly picked up in transportation, handling and transfer include soil dirt, sand, rust and scale. Gasoline contamination in pipeline transportation can introduce small concentrations of lead into distillate fuels. Any fuel additives used to improve fuel storage stability, rust prevention or combustion should not contain ash-forming elements in concentrations which could affect the performance of the fuel in the gas turbine.

Petroleum residual fuels by their very nature are "contaminated" when they leave the refinery and frequently pick up salt-laden water during transportation. Refinery practices include desalting the crude feedstock to a few parts per million of sodium; but since all of the non-volatile components of the feedstock are concentrated in the residual, the sodium content of the residual fuel may be in the 10-25 ppm range. By the time the fuel reaches the turbine site this can be appreciably augmented by seawater (or brackish water) contamination. There will be finely dispersed solids in the residual oil including corrosion products of equipment (rust, sulfide scale) and possibly clay and gypsum from the crude oil feedstock. Vanadium, nickel and iron which are frequently present as oil-soluble complex organic compounds are not amenable to on-site cleanup and are not considered "contaminants" in the context of this discussion of on-site fuel cleanup.

Synthetic liquid fuels transported in the same manner as petroleum fuels would be subject to the same contamination risks. Synthetic liquid fuels with a residual component could also contain mineral carryover from the fossil fuel source; coal or shale. Possible contaminants in this category would include clays, iron minerals, carbonates and possibly alkali halides.

ON-SITE FUEL CLEANUP - GENERAL

On-site liquid fuel cleanup to remove potentially deleterious substances includes (a) standard practices to remove suspended dirt and free water, and (b) special techniques to further clean the fuel to specified maximum impurity levels.

For certain contaminants, preventing the introduction may be the only practical solution. An example of this is leaded gasoline contamination of petroleum fuels. Once the organic lead component is in the fuel it is impossible to remove it at the site. Inhibiting the lead with additives has been reported to have some success, but preventing the contamination has been the workable approach used in the industry. Although not considered in this program, another example of fuels requiring a dedicated transport and storage system are methanol, ethanol or other water-miscible fuels. This is because salt water cannot be removed from these fuels by any practical means at the turbine site.

On-site liquid fuel cleanup in the context of this report refers to techniques and equipment over and above the standard on-site fuel storage, handling and transfer practices. As will be discussed later, these standard practices are important, and their conscientious use can preserve or restore the quality of clean distillate fuels.

Experience to date with fuel treatment has concerned the removal of alkali metal (sodium and potassium) contaminants from petroleum-based liquid fuels. When alkali metals are present, they are usually dissolved salts in a contaminating free-water phase dispersed in the fuel. In some instances it is possible to remove most of the free-water phase by purely mechanical means; for example, purification by centrifugation. In other instances it is necessary to use water extraction to pickup salt contaminants followed by dehydration to desalt the fuel. This water washing technique is the common procedure for residual fuel desalting.

No fuel washing experience was found for shale or coal-derived liquid fuels. If fuel washing is later found to be desirable to clean these liquid fuels, petroleum fuel washing experience may or may not be applicable. Coal liquids, depending on their aromaticity, may have specific gravites nearly the same or greater than that of water. Also, the demulsibility characteristics may not be as favorable as those of petroleum liquid fuels.

A good reference source on gas turbine liquid fuel quality and treatment is the ASTM STP531, Manual on Requirements Handling and Quality Control of Gas Turbine Fuel (1973).

STANDARD SITE PRACTICES FOR LIQUID FUEL HANDLING AND STORAGE

For many distillate type fuels the use of standard practices for liquid fuel handling and storage at the turbine site can restore and/or maintain the clean and dry condition of the fuel as it left the refinery. Where ship or barge transportation has been used, small amounts of salt-laden water are likely to be in the fuel transferred to the site storage tanks. By adequate settling time in properly designed tanks with regular withdrawal of the accumulated layer, petroleum distillate fuels with the required low sodium levels can usually be assured without the addition of special fuel cleaning equipment.

Standard filtration of the liquid fuel will remove suspended particulate matter including rust, dirt, and scale introduced after the fuel left the refinery. Coalescing filters have been used for removal of dispersed free water but usually only as "polishing" filters once the larger fraction water has already been removed by other means.

The recommended practices for on-site fuel storage and handling are not available in detail from a single source, but ASTM Committee D-2 on Petroleum Products and Lubricants is in the process of adding this information in brief summary form as an appendix to D2880-78, Standard Specifications for Gas Turbine Fuel Oils.

MECHANICAL REMOVAL OF FUEL CONTAMINANTS

Although quiescent tank settling of liquid fuel will remove some free salt water and dirt and is a procedure strongly recommended in all fuel systems, it has limitations when low levels of sodium are required in the fuel. Finely dispersed salt water settles very slowly and, if emulsified by natural emulsifying agents or by fuel additives, it will remain dispersed. Settling effectiveness depends on fuel viscosity, specific gravity and lack of thermal current mixing as well as constant attention to removal of the accumulated bottom layer.

Centrifugal separators have been used to remove free salt water to a lower level than is possible by tank settling alone. Such separators are standard in marine diesel fuel systems. The centrifugal separator may be in parallel as a separate tank cleanup system. The latter approach requires a smaller centrifuge when the service fuel tank is small, but it is probably not practical with very large fuel storage tanks.

Centrifugal separators have been effective with distillate fuels and appear to be applicable to low specific gravity (high API gravity) crude oils. Residual fuels would not normally be desalted by simple centrifugation but require water extraction coupled with centrifugation or electrostatic coalescence as described in Section 1.2.5.

In addition to reducing the free water phase to low levels, centrifugal separation will also remove particulate matter thereby decreasing the load on the fuel filters nad protecting the fuel components, such as pumps, check valves and flow dividers.

CONTAMINANT REMOVAL BY FUEL WASHING

Petroleum residual fuels and many crude oils require water washing to remove alkali metal contaminants. Fuel washing system experience with residual and crude oils has been reviewed in the recent EPRI report (See Reference on page 23).

Centrifugation alone does not adequately remove free salt water from these heavy fuels with residual components. The viscosities and specific gravities are too high, and the salt water phase may be finely dispersed; partly due to natural emulsifying agents in residual fuels. In addition, some of the sodium in residual fuels may not be in the free water phase. Some solid salt crystals and sodium-organic compounds may be present. The latter can be formed when the crude is treated with caustic soda during refinery processing.

Fuel washing consists of two steps: (1) mixing the fuel with water to extract the salts into the water; and (2) removal of the salt-laden wash water from the fuel.

Ideally the extraction step should be carried out such that the added water contacts all of the dispersed salt water, even the finest droplets, and any solid salt which may be present. However, this has to be accomplished with forming a water-in-oil emulsion which would be difficult to dehydrate later. This problem was solved by using low shear rate-long residence time mixing techniques along with proprietary chemical demulsifiers. The typical range of the ratio of wash water/ fuel is from 1/20 to 1/10.

The subsequent dehydration step in the overall washing process is accomplished by one of two commercial techniques: centrifugation or electrostatic coalescence with gravity settling. Centrifugation involves high "g" forces for short times. Electrostatic desalting involves slow gravity settling of very large diameter water drops formed by rapid coalescence in a high voltage electric field. The selection of centrifugation or electrostatic coalescence has been on an economic basis or personal choice. In large fuel flow capacity installations, electrostatic coalescence equipment has generally been less expensive than the multiple centrifuge units.

In addition to salt removal, fuel washing systems also remove some suspended solids. Large, heavy particles settle along with the water, and in addition small but water-wettable solid particles tend to migrate into the water phase during the extraction step and are discharged with the waste water.

To increase the degree of contact of the wash water with the heavy fuel during extraction and to increase the rate of water phase separation during the dehydration step, the upper temperature limit for centrifuge systems is just under the boiling point of water. Because electrostatic coalescers are pressurized, they allow higher fuel temperatures if they are required.

Most fuel washing systems have two stages and sometimes three. These multistage systems are designed for counter-current extraction by water. The cleanest water is added to the last stage, the effluent water from which is used in the preceding stage.

Early residual fuel washing systems were all of the centrifuge type. An early system using a fuel with a typical 50 ppm sodium level was designed to produce 5 ppm maximum sodium in the washed fuel, which was the ASTM specification limit for gas turbine fuels at that time when turbine inlet temperatures were much lower than most of todays gas turbines. As turbine inlet temperatures increased and the allowable maximum sodium level was reduced to 1 ppm or below, more efficient fuel washing systems were developed which typically produced less than 1 ppm of sodium and less than 0.5% free residual water in a two-stage system. This two-stage system represents the present state-of-the-art.

Electrostatic coalescing systems for desalting gas turbine heavy fuels were extensions of electrostatic coalescer technology used for many years in oil fields and oil refineries for desalting crude oils. The operational electrostatic coalescence type fuel washing systems have equivalent desalting performance to the centrifuge type systems. At a typical sodium level of 50 ppm and a water/fuel ratio of 1/20 or 1/10 a two-stage system is designed to produce a washed fuel with less than 1 ppm of sodium while a three-stage system yields a 0.5 ppm maximum sodium product.

In addition to removing soluble alkali metal salts, fuel washing will reduce the level of certain other elements. Calcium is found in residual fuels, and it is desirable to keep its concentration low (under 10 ppm) to increase the interval between turbine cleanings to remove ash deposits. A two-stage or three-stage fuel washing system typically reduces the calcium level to about one-half the level in the unwashed fuel. However, there may be exceptions to this depending on the exact combined chemical form of the calcium in a specific residual fuel. Calcium level reduction by water washing has been much less predictable than sodium removal.

The specific gravity of the fuel is a critical parameter in the design and performance of a fuel washing system. Systems have been designed and operated for fuel specific gravities as high as 0.98, but a maximum of 0.96 is preferred. Residual fuels with specific gravities over 0.98 have to be blended with a lighter distillate fuel (a "cutter" stock) to a lower blended specific gravity.

The effluent wash water from fuel washing systems will contain more "sea salt" than the wash water entering the washing system. Disposal of this is normally not a problem. This water will contain small concentrations of demulsifying agents extracted from the fuel. While this problem has not been fully resolved, it appears that the concentrations of such contaminants in the final effluent water would be below toxic thresholds. The real contaminant problem with effluent wash water is the oil contaminant level which may range from a hundred ppm up to nearly a percent. This level depends on the physical and chemical properties of the residual oil being washed and on the mixing intensity experienced in the fuel washing equipment. A typical maximum free-oil level in the U.S. is 15 ppm, which produces "a visible sheen." Simple oil-water separators are used on most fuel washing systems, and some installations have required additional cleanup with standard techniques and equipment developed for waste control. Coal-derived liquids might present additional effluent water problems because phenolic type compounds could be extracted from these fuels into the water phase.

COMMERCIAL FUEL WASHING SYSTEM EXPERIENCE

The recent EPRI report (see Reference, page 23) reviewed the commercial application of residual fuels and crude oils on a worldwide basis including a discussion of the general performance of fuel treatment systems.

Some of the installations in the EPRI report are older systems which are no longer in operation. At the present time, there are approximately ten residual fuel washing systems operating in the U.S. and twice that number overseas, many of which operate on crude oil. The total worldwide installations are about equally divided between centrifuge-based systems and electrostatic coalescers. There have also been centrifuge-type residual fuel washing systems on some merchant ships.

These fuel washing systems covered a range of fuel flow rates from about 25 gpm to several hundred gpm, the latter serving multi-turbine installations.

Practically all of the fuel washing installations are two-stage systems with a few three stage (electrostatic) systems. The multiple stage design not only gives greater salt removal efficiency, but it also provides further reliability for contingency operation.

In the electrostatic coalescence systems, the design capacity is provided by the size of the coalescer tanks. With centrifuges, large fuel capacity systems have multiple centrifuge units in parallel in each stage.

All fuel washing systems have some type of storage tank between the washing system and the turbine system which acts as a buffer and allows the washing equipment to be shutdown for routine or emergency maintenance without jeopardizing the turbine fuel supply.

The fuel treatment systems operating in conjunction with the present generation of gas turbines reduce the sodium (plus potassium) levels to between 0.3 and 1.0 ppm. The allowable limits set by turbine equipment manufacturers for full-load operation are usually 1.0 ppm or 0.5 ppm maximum.

The conclusions of the EPRI study based on turbine user experience were:

- All owners surveyed considered it a practical and realistic practice to burn residual fuel in their gas turbines.
- In all cases, where hot gas path corrosion was identified, it was believed to be due to operation with improperly washed or inhibited fuel or to impurities in the inlet air.
- There are many possible problems that can result from the use of residual fuel. However, solutions have been identified for all of them with one exception.
- The exception to the above is a deposit buildup in the turbine which results in a gradual loss in efficiency and if operation is continued without cleaning, to compressor stall. The solution is periodic water washing but the unit must be cooled down for this process. Abrasive cleaning under load can be done and will restore a portion (approximately 1/2) of the lost capacity.

- It appears to be extremely important for an owner to conduct a periodic analysis (at least daily) of the fuel going to his turbine to determine that it is properly washed and inhibited and contains no otherwise harmful elements.

- Operation with crude oil is similar to that with residual with the additional problem of volatile and flammable vapors that must be guarded against.

- The decision to change to burning residual fuel or crude oil should be based on an economic analysis. There will be increased operating and maintenance costs. However, in many instances in the past (and it appears probable in the future), the savings in fuel cost when burning residual fuel far outweighed the extra cost associated with its use.

WATER WASHING SYNFUELS

At the present time it has not been established whether any of the grades of coal or shale derived liquid fuels potentially available for future gas turbine application will contain significant levels of trace metal contaminants. The 350-650°F boiling range middle distillate and the 650-950°F heavy distillate grades should be free of non-volatile contaminants. Liquid fuels containing residual components (over 1000°F boiling point) could have trace contaminants carried over from the original fossil fuel raw material. Published data on experimental coal liquids indicate the possible presence of silicom, aluminum, iron, calcium titanium, and alkali metals in coal liquids containing residual material. The alkali metals may be both soluble salts and insoluble clays (especially potassium). Shale derived raw liquids fuel compositions which have been reported have shown iron as the main metallic contaminant with arsenic appearing frequently.

The specific gravity of coal-derived liquids may equal or exceed a value of 1.0 making water washing by existing techniques and hardware impossible. From the consideration of specific gravity alone, coal liquids with specific gravities over about 1.02 might be washed in special centrifuge equipment where the heavy phase is the fuel rather than water. In the specific gravity range of 0.98-1.02, dilution with a lower specific gravity compatible liquid fuel might allow washing, if required. No fuel demulsibility data has appeared for these developmental liquid synfuels. Some coal liquids may contain natural emulsifying agents which could make water washing difficult. Chemical demulsifiers developed for petroleum oils have very specific applicability and may not be applicable to coal or shale derived liquid fuels.

REFERENCE DOCUMENT FOR ON-SITE FUEL CLEANUP

"Worldwide Survey of Current Experience Burning Residual and Crude Oil in Gas Turbines", EPRI Report AF-1243, TPS 78-833, December, 1979

(Extensive Bibliography)

NO_x EXHAUST GAS CLEAN-UP

The sources of NOx emissions from gas turbines include, (1) thermal NOx which is formed by oxidation of nitrogen in the air during the combustion process and (2) organic NOx which is formed from nitrogen compounds in the fuel. The formation of thermal NOx depends on the maximum temperature achieved in the reaction zone in the combustor. Organic NOx formation occurs at lower temperatures and most gas turbine combustors currently in use convert a high percentage of fuel bound nitrogen to NOx.

NOx control methods currently being employed on gas turbines are combustion system modifications and water or steam injection. Combustion system modifications that have been incorporated in currently operating gas turbines have been primarily related to leaner fuel/air ratio in the reaction zone which reduces the maximum temperature in the combustor to reduce the formation of thermal NOx. Water or steam injection are effective in reducing thermal NOx by introducing an inert material with high thermal capacity into the combustor reaction zone to reduce the maximum temperature.

Combustion system development work is continuing with the objective of reducing thermal and organic NOx formation with minimum water or steam injection. The development work includes staged combustion, pre-vaporizing and pre-mixing of liquid fuels, catalytic combustion and other concepts.

The need for exhaust gas NOx emission control in the United States is expressed most generally in the 1977 amendments to the Clean Air Act(1) and for gas turbines specifically by the New Source Performance Standards (NSPS) for gas turbines.(2) The 1977 amendments to the Clean Air Act delegated the responsibility to the states for administering the requirements of the act and the states are currently completing their State Implementation Plans (SIP). The SIP's will set the ambient air quality standards and the allowable emissions for stationary sources to meet these standards. The ambient air quality standards and stationary source emission standards adopted in the SIP's are the US standards in 32 states(3,4) with more stringent standards being adopted by the remaining states. California has an implementation plan for each county and the NOx regulations are usually more stringent than those in most SIP's.

The NSPS for gas turbines is based on water or steam injection for NOx emission control and it includes a heat rate correction and an allowance for fuel bound nitrogen to a limit of 0.25% by weight. Current production gas turbines burning distillate fuel derived from petroleum can economically meet these regulations (75 ppmv referenced to 15% oxygen). A requirement for flue gas treatment (FGT) for NOx emission control will depend upon the fuel bound nitrogen content, gas turbine combustion development to reduce the production of NOx from nitrogen chemically bound in the fuel, and future trends toward more stringent NOx emission limitations.(5,6)

The Clean Air Act Amendments of 1977 may have a significant impact on future NOx regulations, since they require each state to submit a revised SIP that provides for the attainment of primary NAAQS for NO_2 by December 31, 1982. The new SIP must also provide for the attainment of NAAQS for areas experiencing severe oxidant problems by December 31, 1987. Since NOx is a precursor for photochemical oxidants, this can result in revised NOx emission limits. The revised SIP's must also address the new source regulatory policies regarding offset and prevention of significant deterioration.

There is no clear cut indication that FGT will be required on gas turbines now or in the future. The potential application of FGT processes that are under development are discussed and related to their potential for application and gas turbine exhaust gas or combined cycle stack gas if a need develops in the future.

The information presented in the literature is related primarily to NOx removal equipment for application cleaning the stack gas from conventional steam plant boilers. The significant difference between gas turbines and conventional steam boilers is the excess air. Gas turbines operate with approximately 300% excess air whereas boilers are operated as near the stoichiometric fuel/air ratio as possible with a maximum of 20% excess air. Thus, the exhaust gas flow for equal combustion heat release for a gas turbine is approximately three times that of a conventional boiler. Stack gas treatment equipment for gas turbine applications must, therefore, be significantly larger for gas turbines to handle the high exhaust gas flow.

The output and thermal efficiency of gas turbines are adversely affected by increased exhaust back pressure. Therefore, FGT equipment must have low pressure drop to enable economical application on gas turbines.

The temperature of the exhaust gas from a gas turbine is in the 800-1000°F range. The high temperature further increases the high volume flow and exceeds the allowable maximum temperature for some processes. Heat recovery equipment is commonly applied to recover the exhaust heat for performing useful work in process heating, steam generation or heating combustion air. The heat recovery equipment can also be employed to reduce the stack gas temperature to the operating range for FGT equipment. The primary purpose of this section of the literature search is to provide a general interpretation of the applicability to gas turbines of FGT equipment under development for conventional steam plants.

The flue gas denitrification processes can be separated into two types, wet or dry, depending on whether or not the NOx is abosrbed into an aqueous solution. With a few exceptions the dry processes are NOx-only removal systems while in general the wet processes are simultaneous sulfur dioxide

(SO_2) and NOx removal systems. Although there are a few examples of wet NOx-only technology, these processes were originally developed for treatment of nitric acid (HNO_3) plant tail gas and may not compete economically with the much simpler dry NOx-only units. Therefore, most of the initial development work on wet NOx removal processes has been in adapting the existing wet flue gas desulfurization technology to simultaneously remove both SO_2 and NOx.

1.3.1 WET FGT PROCESSES

The wet FGT processes can be subdivided into four major categories. These are:

Absorption-reduction
Oxidation-absorption-reduction
Absorption-oxidation
Oxidation-absorption

A comparison of the significant characteristics of these processes is as follows:(7)

	Wet NOx removal process type			
Process characteristics*	Absorption-oxidation	Oxidation-absorption	Oxidation-absorption-reduction	Absorption-reduction
Simultaneous SO_2-NOx removal	-	X	X	X
Achieves high SO_2 removal (95%)	-	X	X	X
Achieves moderate NOx removal (85%)	X	X	X	-
Operating conditions				
Requires absorption catalyst	-	-	X	X
Requires liquid-phase oxidant	X	-	-	-
Requires gas-phase oxidant	-	X	X	-
Requires large absorber	X	X	-	X
Requires flue gas reheat	X	X	X	X
Forms nitrate salts in wastewater	X	X	X	-
Requires specific range of flue gas constituents	X	-	X	X

* An "X" indicates the process has this characteristic.

Developers of the wet FGT processes are:

Absorption-reduction
Asahi Chemical
Chisso Engineering
Kureha
Mitsui Engineering and Shipbuilding
Pittsburgh Environmental and Energy Systems

Oxidation-absorption-reduction
  Chiyoda Thoroughbred 102
  Ishikawajima-Harima Heavy Industries
  Mitsubishi Heavy Industries
  Moretana Calcium
  Moretana Sodium
  Osaka Soda
  Shirogene

Absorption-oxidation
  Hodogaya[a]
  Kobe Steel
  MON Alkali Permanganate
  Nissan Engineering

Oxidation-absorption
  Kawasaki Heavy Industries
  Tokyo Electric-Mitsubishi HI
  Ube

Major plants with wet NOx removal are presented on Table 1.3-1 which is reproduced from Reference No. 8. The Japanese have led the world in the development and application of NOx removal processes on power generation and process plant because of their acute air pollution problem in heavily populated areas.

Essentially all of the NOx in the combustion gas is in the form of NO, which has poor reactivity and is not readily absorbed by most absorbents. NO is oxidized to NO_2 in air, but the oxidation occurs slowly. In many processes, oxidizing agents are used to promote absorption of NOx.

<u>Oxidizing Agents</u>

Ozone (O_3) and chlorine dioxide (ClO_2) are used mainly for the oxidation of NO in the gaseous phase. They oxidize NO to NO_2 within a second but barely oxidize SO_2 to SO_3.

Ozone can oxidize NO to N_2O_5 when added in an excessive amount.

$$NO + O_3 \rightarrow NO_2 + O_2$$

$$2NO + 3O_3 \rightarrow N_2O_5 + 3O_2$$

Ozone is fairly expensive, and costs $1.20 to 1.40 per kilogram. In one Japanese plant a large-scale ozone generator with a capacity of 100 kilograms per hour of ozone is near completion. It can treat about 230,000 Nm^3/hr of flue gas (76 MW conventional steam power plant equivalent) containing 200 ppm NO. The cost of ozone is expected to decrease to some extent with the large generator. The cost of chlorine dioxide is 30 to 40 percent less than that of ozone, but chlorine dioxide has the disadvantage of introducing hydrochloric and nitric acids, which complicate the system.

$$2NO + ClO_2 + \frac{H2O}{\text{moisture}} \rightarrow NO_2 + HNO_3 + HCl$$

Solutions of potassium and sodium permanganates, sodium and calcium hypochlorites, and hydrogen peroxide have been used for the oxidation in the liquid phase, but these chemicals are also expensive.

Oxidation-Absorption and Absorption-Oxidation Processes

In oxidation-absorption processes the NO is first oxidized with a gaseous oxidizing agent and then absorbed. In absorption-oxidation processes the NO is absorbed in a solution containing an oxidizing agent. Usually NOx absorption occurs more slowly in the latter case because NO must be absorbed in the liquor before it can be oxidized. Most plants using nitric acid for such processes as metal washing emit a gas fairly rich in NOx (1000 to 10,000 ppm). However, the amount of gas is not great (500 to 5000 Nm^3/hr.). In many of the plants, all or part of the NO is oxidized to NO_2, and the gas is absorbed in a sodium hydroxide solution. Activated carbon is used in some plants as a catalyst for the oxidation of NO by air. In other plants NOx is absorbed in a solution containing an oxidizing agent such as NaClO or H_2O_2. In both cases the resulting liquor, containing nitrate and nitrite, is sent to a wastewater treatment system. Such processes cannot be applied on a large scale because the treatment does not remove the nitrogen compounds from the wastewater.

Tests have been made in pilot plants to recover nitric acid for industrial use or to recover potassium or calcium nitrate for fertilizer. Those processes do not seem promising because of the high cost and the limited demand for the by-products.

Oxidation-Reduction and Reduction Processes (Simultaneous Removal)

Since 1973 many oxidation-reduction and reduction processes have been developed in which NOx and SOx are absorbed simultaneously. In the oxidation-reduction process NO is first oxidized and then absorbed together with SOx in a slurry or a solution. In the reduction process NO is absorbed with SOx in a liquor containing ferrous ion, which can form an adduct with NO. Usually EDTA (ethylenediamine tetraacetic acid, a chelating compound whose present cost in Japan is about $2700/t) is added to promote the reaction of ferrous ion with NO.(9)

In both cases various reactions occur in the liquor or slurry and result in the reduction of NOx by SO_2 (or sulfite) to NH_3 through imidodisulfonic acid ($HN(SO_3H)_2$), sulfamic acid (H_2NSO_3H), or a salt of either acid.(10)

NOx can be reduced to N_2. The reactions are complex but may be simply described:

$$NH_2SO_3H + NO_2^- \rightarrow N_2 + HSO_4^- + H_2O$$

A compound $Na_2SO_3 \cdot 2NO$ is formed when NO is absorbed in an $NaSO_3$ solution.(11) The compound is stable at high pH (above 8) but decomposes to form Na_2SO_4 and N_2O at lower pH. It is likely that in addition to N_2 or NH_3, N_2O also is formed in some of the wet processes.

$$Na_2SO_3 \cdot 2NO \rightarrow Na_2SO_4 + N_2O$$

In some of the processes a considerable portion of NOx remains in the resulting liquor as a nitrite and nitrate, which would cause a problem in wastewater treatment.

The advantage of such wet processes over dry processes is that they can simultaneously remove SO_2 and NOx without problems of dust and ammonium bisulfate. They have not yet been commercialized on a large scale. Five relatively small commercial plants and seven pilot plants are in operation.

The wet NOx removal processes have certain general advantages and disadvantages as compared with the dry systems. These major advantages include:

1. Simultaneous SO_2-NOx removal may be a potential economic advantage
2. Relatively insensitive to flue gas particulates
3. Higher SO_2 removal (>95%)

On the other hand the major disadvantages of these wet systems include:

1. More expensive processes due to the insolubility of NOx in aqueous solutions
2. Formation of nitrates (NO_3^-) and other potential water pollutants
3. More extensive equipment requirements
4. Formation of low-demand byproducts
5. Flue gas reheat required (however, if a wet SO_2 removal system were used in series with a wet removal system for NOx only, the reheat would have already been incorporated into the design)
6. Only moderate NOx removal
7. Application of some processes may be limited to flue gas with high SOx:NOx ratio

The two primary disadvantages of the wet systems are the high capital and operating costs and the formation of NO_3^- containing wastewater. The generation of NO_3^- salts in most of these processes results in the need to remove these salts from the effluent by either evaporation or biological treatment.

A detailed economic analysis has been performed on the most promising wet processes for US application on conventional steam power plants.(11) The two systems studied were the Asaki and IHI NOx/SOx removal systems. For a 500 MW conventional steam plant, the installed cost and revenue requirements are estimated as follows for a midwest utility generation plant.

	Installed Cost ($/kw)	Revenue Requirement (mills/kwh)
Asaki	233	12.63
IHI	482	19.82

The conclusion from these studies is that the wet processes are not expected to be economical for these plants.(12) Since the gas turbine exhaust gas flow is approximately three times that of conventional steam plants, the cost would be much higher and more unattractive economically.

DRY FGT PROCESSES

The dry flue gas denitrification processes can be subdivided into five major categories. These categories are:

Selective catalytic reduction
Nonselective catalytic reduction
Selective noncatalytic reduction
Absorption
Radiation

A comparison of the significant characteristics of the dry FGT processes are presented on the following table.

	Dry NOx removal process type				
Process characteristics*	Selective catalytic reduction	Nonselective catalytic reduction	Selective noncatalytic reduction	Absorption	Radiation
Simultaneous SO_2-NOx removal	-	X	-	X	X
Achieves moderate SO_2 removal (85%)	-	X	-	X	X
Achieves high NOx removal (90%)	X	X	-	-	X
Operating conditions					
Produces waste steam	-	-	-	X	X
Uses NH_3	X	-	X	-	-
Forms NH4HSO4	X	-	X	-	-
Operates with sensitivity to particulates	X	-	X	X	-
Produces marketable byproduct	-	X	-	X	-
Current development status					
Tested on coal-fired flue gas	-	-	-	X	-
Tested on pilot plant or larger scale	X	-	X	X	X

* An "X" indicates the process has this characteristic.

Developers of dry NOx removal process are as follows:

Selective catalytic reduction
Asahi Glass[a]
Eneron
Exxon
Hitachi, Ltd.
Hitachi Zosen
JGC Paranox
Kobe Steel
Kurabo Knorca
Kureha
Mitsubishi Heavy Industries
Mitsubishi Kakoki Kaisha
Mitsubishi Petrochemical
Mitsui Engineering and Shipbuilding
Mitsui Toatsu
Nippon Kokan
Sumitomo Chemical
Sumitomo Heavy Industries
Takeda
Ube
Unitika
Universal Oil Products-Shell CuO

Nonselective catalytic reduction
The Ralph M. Parsons

Selective noncatalytic reduction
Exxon Thermal DeNOx

Absorption
Foster Wheeler-Bergbau Forschung

Radiation
Ebara-JAERI

The majority of the dry systems currently undergoing development are based on the SCR method and use NH_3 as the reductant. In this method the anhydrous NH_3 is injected into the flue gas after the boiler economizer and the resulting mixture is passed over a proprietary base-metal catalyst. The NH_3 selectively reduces the NOx to molecular N_2 which then passes out of the NOx removal system with the stack gas.

The primary disadvantage associated with the SCR method when applied to coal-fired flue gas is the sensitivity of the catalyst to the higher particulate levels in the flue gas. Although most of these processes have been designed to minimize the effects of dust, either through the type of reactor used or shape of the catalyst particles, most development work was done using heavy oil-fired flue gas. Additional detailed pilot-plant testing on coal-fired flue gas will be needed and is underway by some companies to confirm the ability of these innovations to handle the higher particulate loadings associated with coal combustion.

One additional potential problem is the formation and precipitation of ammonium bisulfate (NH_4HSO_4) downstream from the reduction reactor, particularly in the boiler air heater. The NH_4HSO_4 formation is dependent upon temperature and the NH_3 and sulfur trioxide (SO_3) concentrations. It may become necessary to decrease the mole ratio of NH_3:NOx and thus decrease the denitrification efficiency below 90% to prevent the formation of NH_4HSO_4. The use of a catalyst for the decomposition of NH_3 would provide an alternative method of control though it would increase complexity of capital investment. The development of such catalysts is being conducted by some companies.

A list of major plants using SCR is presented on Table 1.3-2 which is reproduced from Reference No. 8.

The nonselective catalytic reduction processes involve the injection of a fuel or reducing gas into the radiant zone of the boiler to chemically bind the excess oxygen (O_2) and thus minimize the formation of oxides of S and N. For economical operation, this use of a reducing gas will be combined with combustion modifications such as firing with a slightly substoichiometric amount of air to decrease the consumption of reducing gas as much as possible. As this O_2-deficient flue gas containing some SO_2 and NOx is passed over a nonnoble metal catalyst, the SO_2 and NOx are reduced to hydrogen sulfide (H_2S) and molecular N_2. The H_2S is then removed in a conventional Stretford unit and the remaining flue gas is exhausted through the stack. This type of process, in addition to simultaneously removing SO_2 and NOx, produces elemental S as a marketable byproduct. The major disadvantages include the expense of the reducing gas and the possibility of increased corrosion in the boiler due to the high temperature reducing atmosphere.

In the selective noncatalytic reduction processes the NH_3 is injected directly into the upper portion of the boiler to selectively reduce the NOx to molecular N_2. This procedure eliminates the need for any supplemental equipment downstream and results in a process scheme with minimum capital investment. Unfortunately it has the major disadvantages of requiring a higher NH_3:NOx mole ratio and thereby potentially creating more problems with NH_4HSO_4 than catalytic processes, operating in a very narrow temperature range, and yielding only low NOx removal (40-60%). There is also uncertainty concerning the effects of flyash from coal-fired flue gas upon the NOx removal efficiency of this process.

The dry absorption processes are based on the use of activated carbon to absorb both SO_2 and NOx from the flue gas. The absorbent is regenerated at a high temperature to yield a concentrated off-gas stream of SO_2 and molecular N_2. This SO_2 could be used to generate elemental sulfur or by-product sulfuric acid (H_2SO_4).

The disadvantages of this type process include low NOx removal efficiency and high carbon loss.

The radiation process is unique in that the flue gas is bombarded with an electron beam. This radiation converts the particulates, SO_2, and NOx into a powdery, complex mixture which is then removed in an electrostatic precipitator (ESP). The major disadvantages include high initial capital investment, high annual revenue requirements, secondary waste disposal problem, and low (80%) SO_2 removal efficiency.

Although there are many different types of dry and wet processes, in most cases the dry processes have the following advantages over the wet processes.

1. Lower projected total capital investment and lower annual revenue requirements
2. Simpler process with few equipment requirements
3. Higher NOx removal efficiency (90%)
4. More extensive tests in large units (oil-and/or gas-fired boilers)
5. No waste stream generation.

However these dry systems also have the following disadvantages.

1. More sensitive to inlet particulate levels
2. Requirement for ammonia (NH_3) from either an energy-sensitive source (natural gas) or more expensive coal gasification methods
3. Possible emission of NH_3 and ammonium sulfates $(NH_4)_2SO_4$ and bisulfates (NH_4HSO_4); precipitation of same may create fouling of downstream equipment
4. Relatively higher reaction temperatures (350-400°C) which must be located in the power generation cycle before the air preheater or must be attained by auxiliary heating after the preheater

The most critical of these disadvantages is the sensitivity of these processes to inlet particulate levels. Major research is now underway to develop methods to enable dry systems to handle flue gas with high particulate loading. Evaluations are being performed on coal-fired flue gas; however, these tests have not been executed on a very large scale.

Another disadvantage of the dry, selective catalytic reduction (SCR) processes is that the ideal catalyst location may be in the region between the economizer outlet and the air preheater inlet and, hence, the process is intimately involved in the power generation cycle. Therefore, if problems of operating these processes occur, the adverse impacts on the basic utility operations may be greater.

In addition to the above-mentioned disadvantages, the long-term supply of NH_3 for these dry NOx removal processes is a potential problem. NH_3 is the reducing agent for converting NOx to molecular nitrogen (N_2) for the SCR processes (which comprises nearly all of the dry processes and about half of all the NOx removal processes--see Table S-1) and the selective non-catalytic reduction process. With an NH_3:NOx mole ratio of about 1:1 a single 500 MW coal-fired power plant (600 ppm NOx in the flue gas) would consume about 5950 tons/yr. of liquid anhydrous NH_3. In view of the continuing increase in the world's demand of NH_3 and NH_3-based fertilizers, the availability of NH_3 for larger numbers of these dry NOx removal units warrants concern and further investigation.(13)

The economic analysis reported in Reference No. 11 indicates the most attractive FGT process from an economical standpoint is the SCR process. Estimated installed cost of the dry NOx removal system and the average revenue requirements for a 500MW conventional steam plant in a midwest US location based on 1980 dollars are:

	Installed Cost ($/kw)	Revenue Requirement (mills/kwh)
Hitachi Zosen SCR	48.2	3.61
Kurabo Knorca	43.9	2.77
UOP SF GT	38.1	2.13

The SCR process has the potential for application on gas turbines in which heat recovery equipment is installed for reducing the exhaust gas temperature to a level that is satisfactory for the catalyst. One manufacturer, Hitachi Zosen, has conducted tests on a pilot system with simulated gas turbine exhaust gas.(12)

TABLES AND FIGURES

FOR

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Table 1.3-1

Major Plants for NOx Removal from Flue Gas by Wet Processes

Process developer	Type of process	Plant owner	Plant site	Capacity, Nm^3/hr	Source of gas	Completion	By-product
(Tokyo Electric Mitsubishi H.I.)	(Oxidation absorption)	Tokyo Electric	Minami-Yokohama	2,000	Boiler[b]	Dec. 1973	HNO_3
(Tokyo Electric Mitsubishi H.I.)	(Oxidation absorption)	Tokyo Electric	Minami-Yokohama	100,000	Boiler[b]	Oct. 1974	HNO_3
Kawasaki H.I.	(Oxidation absorption)	EPDC	Takehara	5,000	Boiler[c]	Dec. 1975	[Gypsum $Ca(NO_3)_2$]
Nissan Engineering	(Absorption oxidation)	Ijima Metal	Tokyo	1,800	Pickling	July 1973	$NaNO_2$
Nissan Engineering	(Absorption oxidation)	Nissan Chemical	Toyama	3,000	HNO_3 plant	Mar. 1975	$NaNO_3$, NO
(Mitsubishi Metal MKK, Nihon Chem.)	(Absorption oxidation)	Mitsubishi Metal	Omiya	4,000	Boiler[a]	Dec. 1974	HNO_3
Kobe Steel	(Absorption oxidation)	Kobe Steel	Kakogawa	1,000	Furnace[e]	Dec. 1973	Gypsum, N_2
Kobe Steel	(Absorption oxidation)	Kobe Steel	Kahogawa	50,000	Furnace[e]	Mar. 1976	Gypsum, N_2
Hodogaya	(Absorption oxidation	Hodagaya	Koriyama	4,000	Furnace[e]	Oct. 1975	$NaNO_3$, NaCl
(Sumitomo Metal Fujikasui)	(Oxidation reduction)	Sumitomo Metal	Amagasaki	62,000	Boiler[a]	Dec. 1973	($NaNO_3$, NaCl, Na_2SO_4)
(Sumitomo Metal Fujikasui)	(Oxidation reduction)	Toshim Steel	Fuji	100,000	Furnace[d]	Dec. 1974	($NaNO_3$, NaCl, Na_2SO_4)
(Sumitomo Metal Fujikasui)	(Oxidation reduction)	Sumitomo Metal	Osaka	39,000	Boiler[a]	Dec. 1974	($NaNO_3$, NaCl, Na_2SO_4)
Osaka Soda	(Oxidation reduction)	Osaka Soda	Amagaski	60,000	Boiler[a]	Mar. 1976	($NaNO_3$, NaCl, Na_2SO_4)
Shirogane	(Oxidation reduction)	Mitsui Sugar	Kawasaki	48,000	Boiler[a]	Aug. 1974	Na_2SO_4, $NaNO_3$
Chiyoda	(Oxidation reduction)	Chiyoda	Kawasaki	1,000	Boiler[a]	1973	[Gypsum, $Ca(NO_3)_2$]
Mitsubishi H.I.	(Oxidation reduction)	Mitsubishi H.I.	Hiroshima	2,000	Boiler[a]	Dec. 1974	Gypsum, NH_3
Ishikawajima H.I.	(Oxidation reduction)	Ishikawajima H.I.	Yokahama	5,000	Boiler[a]	Sept. 1975	Gypsum, N_2
Kureha Chemical	Reduction	Kureha Chem.	Nishiki	5,000	Boiler[a]	Apr. 1975	Gypsum, N_2
Chisso Corp.	Reduction	Chisso P.C.	Goi	300	Boiler[a]	1974	$(NH_4)_2SO_4$
Mitsui S.B.	Reduction	Mitsui P.C.	Chiba	150	Boiler[a]	1974	H_2SO_4, N_2
Asahi Chemical	Reduction	Asahi Chemical	Mizushima	600	Boiler[a]	1974	Gypsum, N_2

[a] Oil-fired boiler.
[b] Gas-fired boiler.
[c] Coal-fired boiler.
[d] Metal-heating furnace.
[e] Iron-ore sintering furnace.

Table 1.3-2

Major Plants Using Denitrification by Selective Catalytic Reduction (SCR)

Process developer	Plant owner	Plant site	Capacity, Nm^3/hr	Source of gas	Completion
Sumitomo Chemical	Sumitomo Chemical	Sodegaura	30,000	Oil-fired boiler	July 1973
Sumitomo Chemical	Higashi Nihon Methanol	Sodegaura	200,000*	Heating furnace	May 1974
Sumitomo Chemical	Nihon Ammonia	Sodegaura	250,000*	Heating furnace	Mar. 1975
Sumitomo Chemical	Sumitomo Chemical	Anegasaki	100,000*	Gas-fired boiler	Feb. 1975
Sumitomo Chemical	Sumitomo Chemical	Anegasaki	200,000*	Gas-fired boiler	Feb. 1975
Sumitomo Chemical	Sumitomo Chemical	Niihama	200,000*	Heating furnace	Mar. 1975
Sumitomo Chemical	Sumitomo Chemical	Sodegaura	250,000	Oil-fired boiler	Mar. 1976
Sumitomo Chemical	Sumitomo Chemical	Sodegaura	300,000	Oil-fired boiler	Oct. 1976
Hitachi Shipbuilding	Kansai Oil	Sakai	5,000	Oil-fired boiler	Nov. 1973
Hitachi Shipbuilding	Idemitsu Kosan	Chiba	350,000	CO-fired boiler	Nov. 1975
Hitachi Shipbuilding	Shindaikyowa Pet. Chem.	Yokkaichi	440,000	Oil-fired boiler	Dec. 1975
Tokyo Electric-Mitsubishi H.I.	Tokyo Electric	Minamiyokahama	10,000*	Gas-fired boiler	Jan. 1974
Kurabo	Kurabo	Hirakata	5,000	Oil-fired boiler	Nov. 1973
Kurabo	Kurabo	Hirakata	30,000	Oil-fired boiler	Aug. 1975
Kansai Electric-Hitachi Ltd.	Kansai Electric	Sakaiminato	4,000	Oil-fired boiler	Jan. 1975
IHI-Mitsui Toatsu	Chubu Electric	Shinnagoya	8,000	Oil-fired boiler	Oct. 1974
Chubu-MKK	Chubu Electric	Yokkaichi	100	Oil-fired boiler	Oct. 1974
Mitsubishi H.I.	Mitsubishi H.I.	Hiroshima	4,000	Oil-fired boiler	Dec. 1974
Kobe Steel	Kobe Steel	Kakogawa	600	Sintering plant	May 1974
Mitsui Toatsu	Mitsui Toatsu	Sakai	1,000*	Gas-fired boiler	Oct. 1973
Mitsui Toatsu	Mitsui Toatsu	Sakai	3,000	Oil-fired boiler	Oct. 1974
Mitsui Toatsu	San Polymer	Osaka	4,000*	Gas-fired boiler	Oct. 1974
Mitsui Toatsu	Japan Novopan	Sakai	3,000*	Gas-fired boiler	June 1974
Hitachi Ltd.-Mitsubishi P.C.	Mitsubishis P.C.	Yokkaichi	150,000	Oil-fired boiler	Dec. 1975
Hitachi Ltd.	Kawasaki Steel	Chiba	350,000	Coke oven	Oct. 1976
Ube Industries	Chiba Pet. Chem.	Chiba	10,000	Oil-fired boiler	Jan. 1975
Mitsui S.B.-Mitsui P.C.	Mitsui Pet. Chem.	Chiba	200,000	Oil-fired boiler	Sept. 1975
Mitsui S.B.-Mitsui P.C.	Ukishima Pet. Chem.	Chiba	240,000	Oil-fired boiler	Aug. 1976
MKK-Santetsu	Okayama Paper	Okayama	1,500	Oil-fired boiler	Dec. 1974
MKK-Santetsu	Kawasaki Steel	Chiba	1,000	Coke oven	Mar. 1975
MKK-Santetsu	Nippon Yakin	Kawasaki	15,000	Oil-fired boiler	June 1976
Seitetsu Kagaku	Seitetsu Kagaku	Kakogawa	15,000	Oil-fired boiler	June 1975
Japan Gasoline	Kashima Oil	Kashima	50,000	Heating furnace	Nov. 1975
Japan Gasoline	Fuji Oil	Sodegaura	70,000	CO boiler	Mar. 1975
Asahi Glass	Asahi Glass	Keihin	70,000	Glass furnace	Apr. 1976

* Clean gas; those without asterisks are for dirty gas.

1.3.2 Bibliography

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2. Standards of Performance for New Stationary Sources; Gas Turbines - Federal Register, Vol. 44, No. 176, September 10, 1979.

3. Assessment of the Need for NOx Flue Gas Treatment Technology; EPA 600 7-78-215, November 1978.

4. Bureau of National Affairs, Environmental Reporter, State Air Laws, Section 200-566, Washington, D. C.

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11. J. D. Maxwell, T. A. Burnett, and H. L. Faucett, Preliminary Economic Analysis of NOx Flue Gas Treatment Processes. EPA-600/7-80-021, February 1980.

12. Proceedings: Second NOx Control Technology Seminar - EPRI FP-1109-SR, July 1979.

13. T. A. Burnett and H. L. Faucett, Impact of Ammonia Utilization by NOx Flue Gas Treatment Processes - EPA-600/7-79-011, January 1979.

TABLES AND FIGURES

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FOR

1.1/1.6 PETROLEUM DERIVED FUELS

Exhibit A

1. Hussey, C. E. and Johnson, K. W., "Some Operating Experience with Gas Turbines Approaching the Maximum Limits of the Proposed ASTM No. 3 Fuel Specification," ASME No. 68-GT-28, presented in Washington, D.C., March 17-21, 1968.

	Average Fuel Properties for 1966-67 (Panama Canal Company) Gas Turbine Fuel
Physical Properties	
Specific gravity, deg API 60/60 F	27.4
Viscosity, SUV at 100 F	145
Water and sediment percent by Vol.	0.12
Ash percent by weight	0.001
Chemical Properties	
Sodium + potassium ppm	0.85
Vanadium, ppm	1.97
Calcium, ppm	0.38
Lead, ppm	0.02
Magnesium, ppm	0.26
Sulfur, percent by weight	1.2

Exhibit B

2. Schiefer, R. B., "The Combustion of Heavy Distillate Fuels in Heavy Duty Gas Turbines," ASME No. 71-GT-56, presented in Houston, Texas, March 28 - April 1, 1971.

Comparison of No. 2 Heating Oil With
Heavy Distillate Fuel Oils

	#2 Heating Oil	Test Oil No. 1	Test Oil No. 2	Test Oil No. 3	Test Oil No. 4
A.P.I.		34	32	27	31---
Spec. Grav.	.85	---	---	---	.91
Pour Pt. °F	10	25	70	100	120
Temp. req. to give 10 centistokes °F	15	76	125	147	190
Resid. carbon %	.006	.004	.07	---	.39
Dist. 10%	430	510	615	525	---
50%	---	585	675	---	---
90%	585	---	---	740	---
E.P.	625	720	800	750	---

Exhibit C

3. Vermes, Geza, "Heavy Oil or Residual Oil-New Opportunity for the Utility Gas Turbine," ASME No. 71-GT-81, presented in Houston, Texas, March 28 - April 1, 1971.

Typical Properties of a No. 3-GT Test Oil

Specific gravity:

at 120 F	0.484
at 170 F	0.828
at 210 F	0.814

Viscosity: SSU Sec.

at 100 F	200
at 150 F	62
at 200 F	43

Pour point: 80 F

Gross heating value: 19,455 Btu/lb

Ash, ppm	3.4
Zn, ppm	0.08
Fe, ppm	1.19
Mn, ppm	0.06
Pb, ppm	0.13
Ni, ppm	0.06
Cu, ppm	0.15
Mg, ppm	0.01
K, ppm	not detectable
Na, ppm	0.11
V, ppm	0.38

S, as received, percent 0.39

Exhibit D

4. Patterson, J. R., "Operating and Maintenance Experience for Base Load Gas Turbines Using Heavy Fuels - A Case Study," ASME No. 75-GT-4, presented at Houston, Texas, March 2-6, 1975.

Fuel Physical and Chemical Characteristics
(Rhone Progil chlorine plant of Pont-de-Claix, France)

Physical		Chemical		
Viscosity 100 F	40 - 60 CKS	Vanadium	<0.5	ppm
Viscostiy 210 F	5 - 7 CKS	Sodium	<1.0	ppm
Pour point	40 F	Magnesium	<0.5	ppm
Flash point	430 F	Calcium	<1.0	ppm
Carbon residue	0.14 - 0.17%	Potassium	<0.5	ppm
Ash content	10 ppm	Lead	<0.5	ppm
		Sulfur	<1.7	%
		Na + K	<1.0	ppm

Exhibit E

Refining Capacity as of January 1, 1979
(Barrels per calendar day)

	Crude Distillate	Catalytic Cracking	Thermal Cracking	Reforming (gasoline upgrading)
Western Hemisphere	27,713,915	6,423,872	1,031,930	4,729,936
Western Europe	20,328,614	969,485	716,135	2,632,833
Total Non-Communist Areas	63,541,132	8,185,827	2,105,658	8,767,396
Communist Areas	14,748,000	Not	Not Available	Not Available
Available				
Total World	78,289,132	-	-	-

FIGURE 1

PETROLEUM FUELS
VISCOSITY-BOILING RANGE-GRAVITY RELATION

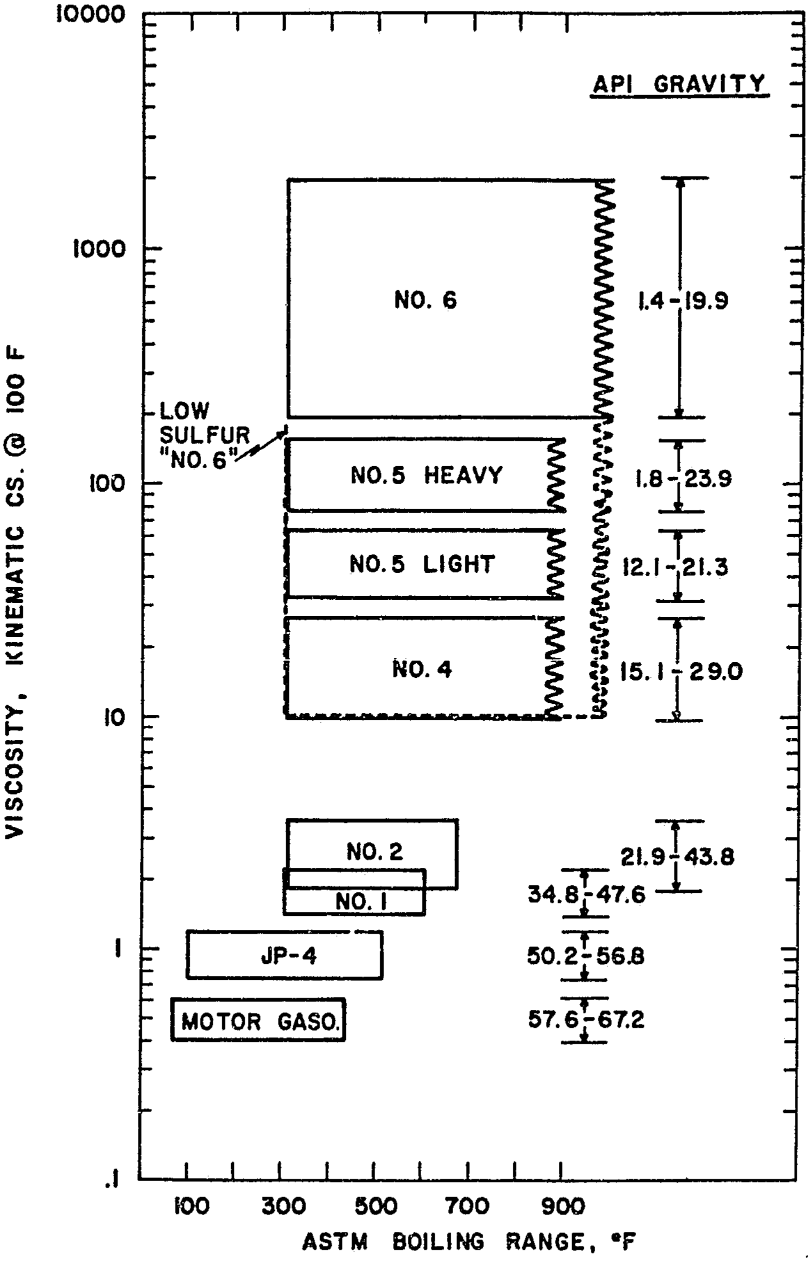

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Figure 2

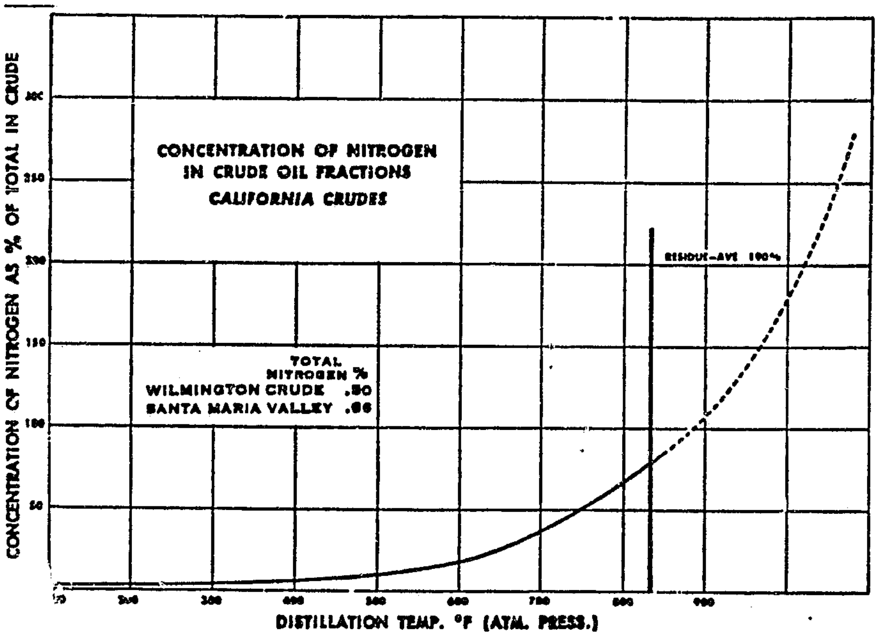

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TABLE 7
ASTM D396 SPECIFICATIONS FOR FUEL OILS

Grade of Fuel Oil	Flash Point, °C (°F)	Pour Point, °C (°F)	Water and Sediment, vol %	Carbon Residue on 10 % Bottoms, %	Ash, weight %	Distillation Temperatures, °C (°F)			Saybolt Viscosity, s[D]				Kinematic Viscosity, cSt[D]						Specific Gravity 60/60°F (deg API)	Copper Strip Corrosion	Sulfur, %
						10 % Point	90 % Point		Universal at 38°C (100°F)		Furol at 50°C (122°F)		At 38°C (100°F)		At 40°C (104°F)		At 50°C (122°F)				
	Min	Max	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Max	Max	Max
No. 1 A distillate oil intended for vaporizing pot-type burners and other burners requiring this grade of fuel	38 (100)	−18[C] (0)	0.05	0.15	...	215 (420)	...	288 (550)	...	...	...	...	1.4	2.2	1.3	2.1	...	...	0.8499 (35 min)	No. 3	0.5
No. 2 A distillate oil for general purpose heating for use in burners not requiring No. 1 fuel oil	38 (100)	−6[C] (20)	0.05	0.35	...	...	282[C] (540)	338 (640)	(32.6)	(37.9)	...	...	2.0[C]	3.6	1.9[C]	3.4	...	...	0.8762 (30 min)	No. 3	0.5[B]
No. 4 Preheating not usually required for handling or burning	55 (130)	−6[C] (20)	0.50	...	0.10	...	...	...	(45)	(125)	...	...	5.8	26.4[F]	5.5	24.0[F]	...	...	...	...	
No. 5 (Light) Preheating may be required depending on climate and equipment	55 (130)	...	1.00	...	0.10	...	...	...	(>125)	(300)	...	...	>26.4	65[F]	>24.0	58[F]	...	...	...	...	
No. 5 (Heavy) Preheating may be required for burning and, in cold climates, may be required for handling	55 (130)	...	1.00	...	0.10	...	...	...	(>300)	(900)	(23)	(40)	>65	194[F]	>58	168[F]	(42)	(81)	...	...	
No. 6 Preheating required for burning and handling	60 (140)	[G]	2.00[E]	...	...	...	...	...	(>900)	(9000)	(>45)	(300)	...	...	...	...	>92	638[F]	...	...	...

[A] It is the intent of these classifications that failure to meet any requirement of a given grade does not automatically place an oil in the next lower grade unless in fact it meets all requirements of the lower grade.

[B] In countries outside the United States other sulfur limits may apply.

[C] Lower or higher pour points may be specified whenever required by conditions of storage or use. When pour point less than −18°C (0°F) is specified, the minimum viscosity for grade No. 2 shall be 1.7 cSt (31.5 SUS) and the minimum 90 % point shall be waived.

[D] Viscosity values in parentheses are for information only and not necessarily limiting.

[E] The amount of water by distillation plus the sediment by extraction shall not exceed 2.00 %. The amount of sediment by extraction shall not exceed 0.50 %. A deduction in quantity shall be made for all water and sediment in excess of 1.0 %.

[F] Where low sulfur fuel oil is required, fuel oil falling in the viscosity range of a lower numbered grade down to and including No. 4 may be supplied by agreement between purchaser and supplier. The viscosity range of the initial shipment shall be identified and advance notice shall be required when changing from one viscosity range to another. This notice shall be in sufficient time to permit the user to make the necessary adjustments.

[G] Where low sulfur fuel oil is required, Grade 6 fuel oil will be classified as low pour +15°C (60°F) max or high pour (no max). Low pour fuel oil should be used unless all tanks and lines are heated.

TABLE 2
ASTM D975 SPECIFICATIONS FOR DIESEL FUEL OILS

Grade of Diesel Fuel Oil	Flash Point, °C	Cloud Point °C (°F)	Water and Sediment, vol %	Carbon Residue on, 10 % Residuum, %	Ash, weight %	Distillation Temperatures, °C (°F)		Viscosity				Sulfur,[D] weight %	Copper Strip Corrosion	Cetane Number[E]
						90 % Point		Kinematic, cSt[G] at 40°C		Saybolt, SUS at 100°F				
	Min	Max	Max	Max	Max	Min	Max	Min	Max	Min	Max	Max	Max	Min
No. 1-D A volatile distillate fuel oil for engines in service requiring frequent speed and load changes	38 (100)	[B]	0.05	0.15	0.01	...	288 (550)	1.3	2.4	...	34.4	0.50	No. 3	40[F]
No. 2-D A distillate fuel oil of lower volatility for engines in industrial and heavy mobile service.	52 (125)	[B]	0.05	0.35	0.01	282[C] (540)	338 (640)	1.9	4.1	32.6	40.1	0.50	No. 3	40[F]
No. 4-D A fuel oil for low and medium speed engines.	55 (130)	[B]	0.50	...	0.10	...	...	5.5	24.0	45.0	125.0	2.0	...	30[F]

[A] To meet special operating conditions, modifications of individual limiting requirements may be agreed upon between purchaser, seller, and manufacturer.

[B] It is unrealistic to specify low-temperature properties that will ensure satisfactory operation on a broad basis. Satisfactory operation should be achieved in most cases if the cloud point (or wax appearance point) is specified at 6°C above the tenth percentile minimum ambient temperature for the area in which the fuel will be used. The tenth percentile minimum ambient temperatures for the U.S. are shown in Appendix X2. This guidance is of a general nature; some equipment designs, use flow improver additives, fuel properties, and/or operations may allow higher or require lower cloud point fuels. Appropriate low temperature operability properties should be agreed on between the fuel supplier and purchaser for the intended use and expected ambient temperatures.

[C] When cloud point less than −12°C (10°F) is specified, the minimum viscosity shall be 1.7 cSt (or mm²/s) and the 90 % point shall be waived.

[D] In countries outside the U.S.A., other sulfur limits may apply.

[E] Where cetane number by Method D 613 is not available, ASTM Method D 976, Calculated Cetane Index of Distillate Fuels[3] may be used as an approximation. Where there is disagreement, method D 613 shall be the referee method.

[F] Low-atmospheric temperatures as well as engine operation at high altitudes may require use of fuels with higher cetane ratings.

[G] 1 cSt = 1 mm²/s.

[H] The values stated in SI units are to be regarded as the standard. The values in U.S. customary units are for information only.

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TABLE 3
ASTM D1655 SPECIFICATION FOR AVIATION TURBINE FUELS

Property	Jet A or Jet A-1	Jet B	ASTM Test Method[B]
Acidity, total max, mg KOH/g	0.1	...	D 974 or D 3242
Aromatics, vol, max, %	20[C]	20[C]	D 1319
Sulfur, mercaptan,[D] wt, max, %	0.003	0.003	D 1323
Sulfur, total wt, max, %	0.3	0.3	D 1266 or D 1552 or D 2622
Distillation temperature, °F (°C):			
10% recovered, max, temp	400 (204.4)	...	D 86
20% recovered, max, temp	...	290 (143.3)	
50% recovered, max, temp	report	370 (187.8)	
90% recovered, max, temp	report	470 (243.3)	
Final boiling point, max, °F (°C)	572 (300)	...	
Distillation residue, max, %	1.5	1.5	
Distillation loss, max, %	1.5	1.5	
Flash point, min. °F (°C)	100 (37.8)		D 56 or D 3243[E]
Gravity, max, °API (min, sp gr) at 60°F	51 (0.7753)	57 (0.7507)	D 1298
Gravity, min, °API (max, sp gr) at 60°F	37 (0.8398)	45 (0.8017)	D 1298
Vapor pressure, max, lb	...	3	D 323
Freezing point, max, °C	−40[E] Jet A −50[E] Jet A-1	−50[E]	D 2386
Viscosity −4°F (−20°C) max, cSt	8	...	D 445
Net heat of combustion, min, Btu/lb	18.400[F]	18.400[F]	D 1405 or D 2382
Combustion properties: one of the following requirements shall be met:			
(1) Luminometer number, min or	45	45	D 1740
(2) Smoke point, min or	25	25	D 1322
(3) Smoke point, min and	20[G]	20[G]	D 1322
Naphthalenes, vol, max, %	3	3	D 1840
Corrosion, copper strip 2 h at 212°F (100°C) max	No. 1	No. 1	D 130
Thermal stability: one of the following requirements shall be met:			
(1) Filter pressure drop, max, in. Hg	3	3	D 1660[H]
Preheater deposit less than	Code 3	Code 3	
(2) Filter pressure drop, max, mm Hg	25	25	D 3241[I]
Tube deposit less than	Code 3	Code 3	
Existent gum, mg/100 ml, max	7	7	D 381
Water reaction:			
Separation rating, max	2	2	D 1094
Interface rating, max	1b	1b	D 1094
Additives	See 4.2		
Electrical conductivity, pS/m	[J]	[J]	D 2624 or D 3114

[A] The requirements herein are absolute and are not subject to correction for tolerance of the test methods. If multiple determinations are made, average results shall be used.

[B] The test methods indicated in this table are referred to in Section 9.

[C] Jet A with an aromatics content over 20 volume % but not exceeding 25 volume % and Jet A-1 or Jet B with an aromatics content over 20 volume % but not exceeding 22 volume % is permitted provided the supplier (seller) notifies the purchaser of the volume, distribution and aromatic content within 90 days of date shipment unless other reporting conditions as agreed to by both parties. This footnote is subject to reapproval in 1981.

[D] The mercaptan sulfur determination may be waived if the fuel is considered sweet by the doctor test described in 4.2 of Specification D 484, for Hydrocarbon Drycleaning Solvents.[1]

[E] Other freezing points may be agreed upon between supplier and purchaser.

[F] Use for Jets A and A-1 the value calculated from Table 8 or Eqs 5, and 9 in Method D 1405. Use for Jet B the value calculated from Table 6 or Eqs 5, and 7 in Method D 1405. Method D 2382 may be used as an alternative. In case of dispute, Method D 2382 must be used.

[G] Jet A having a smoke point less than 20 but not less than 18 and a maximum of 3 volume % of naphthalenes and Jet A-1 or Jet B having a smoke point less than 20 but not less than 19 and a maximum of 3 volume of naphthalenes is permitted provided the supplier (seller) notifies the purchaser of the volume, distribution, smoke point and naphthalene content within 90 days of date shipment unless other reporting conditions as agreed to by both parties. This footnote is subject to reapproval in 1981.

[H] Thermal stability test shall be conducted for 5 h at 300°F (148.9°C) preheater temperature 400°F (204.4°C) filter temperature, and at a flow rate of 6 lb/h.

[I] Thermal stability test (JFTOT) shall be conducted for 2.5 h at a control temperature of 260°C but if the requirements of Table 1 are not met, the test may be conducted for 2.5 h at a control temperature of 245°C. Results at both test temperatures shall be reported in this case. Tube deposits shall always be reported by the Visual Method, a rating by the Tube Deposit Rating (TDR) optical density method is desirable but not mandatory.

[J] A limit of 50 to 300 conductivity units (pS/m) applies only when an electrical conductivity additive is used and under the

TABLE 4
ASTM D2880 SPECIFICATION FOR GAS TURBINE FUEL OILS

Designation[A]	Grade of Gas Turbine Fuel Oil	Flash Point, °C (°F)[B]	Pour Point, °C (°F)[B]	Water and Sediment, vol %	Carbon Residue on 10 % Residuum, wt %	Ash, wt %	Distillation Temperature, 90 % Point[B]		Kinematic Viscosity, cSt[C]			Saybolt Viscosity, s[B]			Specific Gravity 60/60°F (°API)[B]
							°C (°F)	°C (°F)	at 40°C	(104°F)	at 50°C (122°F)	Universal at 38°C (100°F)		Furol at 50°C (122°F)	
		min	max	max	max	max	min	max	min	max	max	min	max	max	max
No. 0-GT	A naphtha or other low-flash hydrocarbon liquid.	[D]	...	0.05	0.15	0.01	...	...	[D]	...	...	...	...	...	...
No. 1-GT	A distillate for gas turbines requiring a fuel that burns cleaner than No. 2-GT.	38 (100)	−18[E] (0)	0.05	0.15	0.01	...	288 (550)	1.3	2.4	...	...	(34.4)	...	0.850 (35 min)
No. 2-GT	A distillate fuel of low ash suitable for gas turbines not requiring No. 1-GT.	38 (100)	−6[E] (20)	0.05	0.35	0.01	282 (540)	338 (640)	1.9	4.1	...	(32.6)	(40.2)	...	0.876 (30 min)
No. 3-GT	A low-ash fuel that may contain residual components.	55 (130)	...	1.0	...	0.03	...	...	5.5	...	638	(45)	...	(300)	...
No. 4-GT	A fuel containing residual components and having higher vanadium content than No. 3-GT.	66 (150)	...	1.0	...	...	...	...	5.5	...	638	(45)	...	(300)	...

[A] No. 0-GT includes naphtha, Jet B fuel, and other volatile hydrocarbon liquids. No. 1-GT corresponds in general to Specification D 396 Grade No. 1 fuel and Classification D 975 Grade No. 1-D diesel fuel in physical properties. No. 2-GT corresponds in general to Specification D 396 Grade No. 2 fuel and Classification D 975 Grade No. 2-D diesel fuel in physical properties. No. 3-GT and No. 4-GT viscosity range brackets Specification D 396 Grade No. 4, No. 5 (light), No. 5 (heavy) and No. 6 and Classification D 975 Grade No. 4-D diesel fuel in physical properties.

[B] Values in parentheses are for information only and may be approximate.

[C] 1 cSt = 1 mm^2/s.

[D] When flash point is below 38°C, or when kinematic viscosity is below 7.3 cSt at 40°C, or when both conditions exist, the turbine manufacturer should be consulted with respect to safe handling and fuel system design.

[E] For cold weather operation, the pour point should be specified 6°C below the ambient temperature at which the turbine is to be operated except where fuel heating facilities are provided. When a pour point less than −18°C is specified for Grade No. 2-GT, the minimum viscosity shall be 1.7 cSt, and the minimum 90 % point shall be waived.

[F] Gas turbines with waste heat recovery equipment may require sulfur limits in the fuel to prevent cold-end corrosion (see Appendix X2.4.1.11).

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TABLE 5
BERC-API SURVEY OF GRADE 1 FUELS

Heating oil survey, 1979

Geographic distribution of heating oils Districts within region Additional districts Number of fuels		Eastern region A,B,C D,E,F,G,M 34			Southern region D A,B,C,E,F,G,I,J,K 14			Central region E,F,G A,B,C,D,H,I,J 33			Rocky Mountain region H,I,J,K D,E,F,G,L,M,N,O,P 13			Western region L,M,N,O,P A,B,D,H,I,K 16		
Test	ASTM	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	39.3	43.1	47.8	40.7	42.7	44.3	39.3	42.4	45.2	40.4	42.3	44.7	38.8	42.7	46.9
Flash point, °F	D56	120	–	162	126	–	152	114	–	160	122	–	152	110	–	168
Viscosity at 100° F, cs	D445	1.4	1.64	2.0	1.4	1.64	1.92	1.4	1.70	2.0	1.4	1.69	2.0	1.4	1.56	1.82
Cloud point, °F	D2500	-68	–	8	-68	–	8	-52	–	0	-54	–	-26	-66	–	-26
Pour point, °F	D97	-70	–	-10	-70	–	-30	-60	–	-10	-80	–	-30	-80	–	-30
Sulfur content, wt%	D129	0.004	0.064	0.25	0.01	0.065	0.17	0.01	0.087	0.301	0.004	0.106	0.301	0.001	0.064	0.15
Aniline point, °F	D611	140.0	146.5	163	128	142.9	149.2	128	145.5	155	136.9	147.0	155	132.1	144.3	160
Carbon residue on 10%, wt%	D524	0.00	0.056	0.14	0.01	0.059	0.1	0.00	0.052	0.157	0.00	0.053	0.157	0.00	0.068	0.13
Water and sediment, vol%	D1796	0.00	0.0004	0.005	0.0	0.0	<0.05	0.00	0.0002	0.005	0.000	0.0001	0.001	0.00	0.001	0.01
Gross Heat of Combustion		131,189	133,881	136,063	133,167	134,107	135,244	132,654	134,234	136,063	132,939	134,296	135,419	131,693	134,084	136,357
Distillation temp, °F volume recoverd:	D86															
IBP		325	350	392	335	359	378	315	349	378	323	342	373	299	332	382
10%		356	384	419	364	386	411	354	384	412	363	382	412	342	372	400
50%		394	425	452	401	426	449	401	428	452	410	426	449	382	418	494
90%		444	478	505	445	480	502	450	483	503	456	486	521	435	472	518
End point		436	519	558	500	524	549	500	526	550	508	530	566	487	516	550

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 6
BERC-API SURVEY OF GRADE 2 FUELS

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region			Central region			Rocky Mountain region			Western region		
Districts within region		A,B,C			D			E,F,G			H,I,J,K			L,M,N,O,P		
Additional districts		D,E,F,G			A,B,C,E,F,G,I,J			A,B,C,D,H,I,J			D,E,F,G,L,M,N,O,P			H,I,K		
Number of fuels		55			24			41			19			16		
Test	ASTM	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	22.9	35.0	45.7	29.8	35.2	45.7	22.9	34.7	40.6	32.4	35.1	40.6	32.4	35.0	39.3
Flash point, °F	D56	130	-	200	144	-	196	130	-	210	130	-	204	138	-	204
Viscosity at 100° F, cs	D445	2.01	2.64	3.35	2.0	2.69	3.40	2.0	2.59	3.34	2.0	2.69	3.7	2.2	2.86	3.57
Cloud point, °F	D2500	<-26	-	16	-6	-	16	<-26	-	16	-12	-	10	-4	-	34
Pour point, °F	D97	-40	-	5	-30	-	0	-40	-	5	-40	-	0	-40	-	10
Sulfur content, wt%	D129	0.01	0.215	0.48	0.08	0.203	0.46	0.03	0.235	0.46	0.03	0.266	0.45	0.08	0.26	0.42
Aniline point, °F	D611	68	141.8	180	131.0	143.2	169	68	139.1	180	122	141.3	152	122	144.1	153.0
Carbon residue on 10%, wt%	D524	0.01	0.106	0.34	0.015	0.112	0.34	0.016	0.111	0.28	0.056	0.131	0.26	0.02	0.094	0.15
Water and sediment, vol%	D1796	0.00	0.0001	0.002	[illegible]	0.0002	0.002	0.00	0.0	0.0	0.000	0.001	0.005	0.00	0.004	0.05
Gross Heat of Combustion, mm Hg		132,371	138,615	146,089	132,371	138,524	141,778	135,302	138,805	146,089	135,302	138,513	140,187	136,063	138,651	140,187
Distillation temp, °F volume recoverd:	D86															
IBP		315	372	437	329	380	444	322	376	444	328	376	432	328	382	428
10%		384	424	468	392	433	474	378	427	474	378	431	478	387	439	479
50%		442	498	543	454	502	543	442	498	543	454	501	535	479	511	558
90%		530	589	639	544	591	639	530	586	620	544	585	616	560	596	635
End point		572	641	702	600	642	702	572	637	680	600	632	667	604	642	690

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 7
BERC-API SURVEY OF GRADE 4 FUELS

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region	Central region			Rocky Mountain region			Western region
Districts within region		A,B,C			D	E,F,G			H,I,J,K			L,M,N,O,P
Additional districts		E,F,G				C,I,J			G			
Number of fuels		4			-	3			5			-
Test	ASTM	Minimum	Average	Maximum	No Analyses	Minimum	Average	Maximum	Minimum	Average	Maximum	No Analyses
Gravity, °API	D287	18.9	22.3	29.4	-	18.9	20.0	21.2	15.5	19.7	29.5	-
Flash point, °F	D93	150	-	236	-	150	-	240	158	-	276	-
Viscosity at 100° F, cs	D445	8.26	17.26	34.1	-	1[illegible].7	14.0	15.3	14.4	18.2	23.4	-
Pour point, °F	D97	-10	-	80	-	-[illegible]	-	65	-15	-	65	-
Sulfur content, wt%	D129	0.47	0.70	0.80	-	0.76	0.84	0.97	0.59	1.11	1.50	-
Carbon residue on 100%, wt%	D524	-	-	-	-	-	-	-	0.6	4.4	8.8	-
Ash, wt%	D482	0.9	0.012	0.02	-	0.015	0.018	0.02	0.016	0.019	0.02	-
Water and sediment, vol%	D1796	0.05	0.07	0.1	-	0.05	0.08	0.1	0.05	0.09	0.11	-
Gross Heat of Combustion Btu/gal		142,025	146,474	148,640	-	147,169	147,915	148,640	141,963	148,156	150,834	-

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 8
BERC-API SURVEY OF GRADE 5 (LIGHT) FUELS

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region	Central region			Rocky Mountain region			Western region
Districts within region		A,B,C			D	E,F,G			H,I,J,K			L,M,N,O,P
Additional districts		E,F,G				C						
Number of fuels		2			-	6			3			-
Test	ASTM	Minimum	Average	Maximum	No Analyses	Minimum	Average	Maximum	Minimum	Average	Maximum	No Analyses
Gravity, °API	D287	16.8		18.0	-	12.5	16.1	18.0	3.8	13.3	25.0	-
Flash point, °F	D93	170		182	-	166	-	200	150	-	200	-
Viscosity												
at 100° F, cs	D445	39		51.1	-	29.6	40.6	51.1	21.0	48.5	76.0	-
at 122° F, Furol sec	D88	-		-	-	-	-	-	-	-	-	-
Pour point, °F	D97	-10		50	-	-15	-	85	30	-	70	-
Sulfur content, wt%	D129	0.83		1.01	-	0.83	1.24	1.9	0.56	1.29	1.9	-
Carbon residue on 100%, wt%	D524	-		-	-	3.89	6.55	9.2	-	-	-	-
Ash, wt%	D482	0.01		0.011	-	0.0	0.01	0.02	-	-	-	-
Water and sediment, vol%	D1796	0.05		0.20	-	0.0	0.08	0.20	-	-	-	-
Gross Heat of Combustion, Btu/gal		149,219		149,993	-	149,219	150,481	152,785	144,764	152,296	158,490	-

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 9
BERC-API SURVEY OF GRADE 5 (HEAVY) FUELS

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region		Southern region	Central region		Rocky Mountain region			Western region		
Districts within region		A,B,C		D	E,F,G		H,I,J,K			L,M,N,O,P		
Additional districts		E			C		E,G					
Number of fuels		2		1	2		3			4		
Test	ASTM	Minimum	Maximum	(1 fuel)	Minimum	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	16.4	18.4	18.3	16.4	23.1	17.7	21.1	23.1	11.1	14.7	18.4
Flash point, °F	D93	178	200	186	170	176	145	-	200	192	-	206
Viscosity												
at 100° F, cs	D445	91.7	113.04	500	91.7		133	144.3	155.6	79	117	140
at 122° F, Furol sec	D88	-	-	-	31			31			31.3	
Pour point, °F	D97	-	-	-20	0		0		90	-10	-	10
Sulfur content, wt%	D129	0.90	0.95	1.78	0.7	0.90	0.7	1.27	2.23	1.00	1.47	1.7
Carbon residue on 100%, wt%	D524	4.6		-	-	-		5.51		6.41	6.94	7.41
Ash, wt%	D482	0.018		0.0285	-	-		0.03		0.02	0.026	0.04
Water and sediment, vol%	D1796	0.05	0.1	0.05	0.1			0.05		0.1	0.15	0.3
Gross Heat of Combustion, Btu/gal		148,962	150,251	149,026	145,962	150,251	145,962	147,218	149,412	148,962	151,343	153,699

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TABLE 10
BERC-API SURVEY OF GRADE 6 FUELS

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region			Central region			Rocky Mountain region			Western region		
Districts within region		A,B,C			D			E,F,G			H,I,J,K			L,M,N,O,P		
Additional districts		D,E,F,G			A,B,C,G			B,C,D,H,J,O			E,F,G,O			G,J		
Number of fuels		29			23			21			9			21		
Test	ASTM	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	9.8	15.0	24.5	8.4	13.6	22.8	5.7	13.2	19.7	1.6	11.3	19.6	-4.5	13.3	23.5
Flash point, °F	D93	170	-	330	176	-	246	152	-	250	160	-	350	168	-	240
Viscosity at 122° F, Furol sec	D88	26.3	177.0	360	21.3	202.2	488.2	23.6	194.6	360	72	149.7	292	30	152.9	306
Pour point, °F	D97	5	-	95	10	-	90	15	-	65	15	-	90	15	-	85
Sulfur content, wt%	D129	0.23	1.30	3.0	0.32	1.65	3.0	0.49	1.53	2.9	0.9	1.59	2.9	0.19	1.27	3.1
Carbon residue on 100%, wt%	D524	0.34	6.86	11.11	3.7	6.68	10.9	0.88	8.48	16	6.19	12.2	17.2	3.8	8.07	11
Ash, wt%	D482	0.00	0.036	0.19	0.002	0.024	0.07	0.00	0.029	0.077	0.0	0.031	0.06	0.001	0.034	0.09
Water by distillation, vol%	D95	0.0	0.05	0.2	0.0	0.08	0.4	0.00	0.08	0.2	0.00	0.05	0.1	0.0	0.06	0.1
Sediment by extraction, wt%	D473	0.001	0.07	0.25	0.0	0.04	0.1	0.01	0.08	0.3	0.01	0.02	0.07	0.01	0.05	0.18
Gross Heat of Combustion, Btu/gal		145,079	151,160	154,550	146,152	152,055	155,468	148,127	152,325	157,241	148,191	153,552	159,935	145,710	152,151	163,922

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 11
BERC-API SURVEY OF TYPE CB (CITY BUS) FUELS
(84 No. 1-D and 24 No. 2-D Fuels)

Diesel fuel survey, 1979

Geographic distribution of diesel fuels		Eastern region			Southern region			Central region			Rocky Mountain region			Western region		
Districts within region		A,B,C			D			E,F,G			H,I,J,K			L,M,N,O,P		
Additional districts		D,E,F,G			A,B,C,E,F,G,I			A,B,C,D,I,J,K			D,E,F,G,L,M,N,O,P			H,I,J,K		
Number of fuels		30			14			31			16			16		
Test	ASTM	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	34.3	42.1	46.8	31.4	40.4	44.1	32.5	40.8	45.1	34.7	40.6	45.1	32.6	40.4	47.7
Flash point, °F	D93	120	-	186	124	-	178	120	-	186	124	-	178	120	-	212
Color:																
ASTM	D1500	L0.5	-	1.0	0.5	-	1.0	0.0	-	1.0	0.5	-	0.5	L0.5	-	L1.0
Saybolt chromometer	D156	+30	-	+16	+30	-	+17	+30	-	+16	+30	-	+17	+30	-	+12
Viscosity at 100° F:																
Kinematic, cs	D445	1.4	1.84	3.1	1.4	1.89	2.83	1.4	1.98	3.1	1.4	2.01	3.6	1.4	1.94	3.60
Saybolt Universal, sec.	D88	-	32.1	36.3	-	32.2	35.4	-	32.5	36.3	-	32.6	37.9	-	32.4	37.9
Cloud point, °F	D2500	-52	-	10	<-60	-	4	-54	-	6	<-76	-	8	<-76	-	22
Pour point, °F	D97	-70	-	0	-70	-	-5	-60	-	-30	-80	-	20	-30	-	20
Sulfur content, wt%	D129	0.0	0.084	0.30	0.01	0.090	0.27	0.01	0.152	0.41	0.002	0.153	0.42	0.002	0.108	0.42
Aniline point, °F	D611	138.5	145.3	153.0	132.0	144.7	151.6	138.5	146.6	136.5	133.5	144.1	156.5	133.5	140.2	151.0
Carbon residue on 10%, wt%	D524	0.00	0.055	0.15	0.00	0.066	0.13	0.00	0.085	0.34	0.00	0.075	0.34	0.00	0.077	0.15
Ash, wt%	D482	0.000	0.0004	0.001	0.000	0.0015	0.01	0.000	0.0004	0.0013	0.000	0.0013	0.01	0.0000	0.0013	0.01
Cetane number	D613	41	47.8	52	42	47.1	52	41	47.0	52	38.9	45.0	51	38.9	47.1	56
Cetane index	D975	40.3	52.2	63.1	46.3	48.6	52.5	44.6	49.0	53.6	45.1	50.3	53.6	45.4	50.5	56.5
Distillation temp, °F																
volume recovered:	D86															
IBP		301	353	396	328	363	393	301	353	402	326	360	402	300	355	395
10%		364	390	460	364	394	441	364	395	460	360	395	450	359	396	469
50%		400	437	522	400	442	524	400	446	522	404	443	535	428	442	533
90%		450	494	594	454	499	600	454	510	605	454	503	610	454	501	619
End point		490	538	648	498	543	638	490	554	644	490	548	650	503	545	652

From Shelton, E. M., "Diesel Fuel Oils, 1979," Report No. BETC/PPS-79/5, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 12
BERC-API SURVEY OF TYPE T-T (TRUCKS AND TRACTORS) FUEL
(27 No. 1-D and 173 No. 2-D Fuels)

Diesel fuel survey, 1979

Geographic distribution of diesel fuels Districts within region Additional districts Number of fuels		Eastern region A,B,C D,E,F,G,J 53			Southern region D A,B,C,E,F,G,I,J 26			Central region E,F,G A,B,C,D,H,I,J,K,L,M,N,O 62			Rocky Mountain region H,I,J,K C,D,E,F,G,L,M,N,O,P 33			Western region L,M,N,O,P G,H,I,J,K 28		
Test	**ASTM**	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**	**Minimum**	**Average**	**Maximum**
Gravity, °API	D287	29.8	35.7	46.8	29.8	34.5	42.5	29.8	36.4	44.8	32.8	37.0	43.9	31.1	36.0	42.5
Flash point, °F	D93	140	-	192	144	-	192	124	-	222	124	-	188	128	-	212
Color, ASTM	D1500	L0.5	-	1.5	L0.5	-	1.5	0.0	-	L2.0	0.5	-	1.5	0.5	-	2.0
Viscosity at 100° F:																
Kinematic, cs	D445	1.57	2.67	3.40	1.37	2.84	3.40	1.63	2.67	3.63	1.54	2.57	3.63	1.43	2.76	4.0
Saybolt Universal, sec.	D88	-	34.9	37.3	-	35.4	37.3	-	34.9	38.0	-	34.5	38.0	-	35.2	39.2
Cloud point, °F	D2500	<-40	-	16	<-24	-	18	-52	-	18	-68	-	22	-64	-	46
Pour point, °F	D97	<-40	-	10	<-25	-	10	-50	-	15	-60	-	20	-70	-	20
Sulfur content, wt%	D129	0.01	0.200	0.50	0.01	0.242	0.89	0.00	0.242	0.46	0.030	0.254	0.590	0.01	0.23	0.590
Aniline point, °F	D611	113.0	142.0	167	128.0	143.1	154.0	113.0	145.3	176	128.0	145.7	155.4	139.5	145.7	155.0
Carbon residue on 10%, wt%	D524	0.00	0.101	0.32	0.00	0.105	0.32	0.00	0.111	0.34	0.00	0.092	0.34	0.03	0.084	0.15
Ash, wt%	D482	0.000	0.0014	0.01	0.000	0.0022	0.01	0.000	0.0013	0.01	0.030	0.0012	0.01	0.0000	0.0013	0.01
Cetane number	D613	39	45.9	54	40.2	45.1	52	39	46.5	55.9	41	47.0	51	43.5	46.8	51.0
Cetane index	D975	37.1	48.7	63.1	39.3	47.8	54.6	39.3	49.3	57.4	39.3	49.7	56.3	46.6	50.1	54.0
Distillation temp, °F																
volume recovered:	D86															
IBP		301	380	430	344	383	430	301	376	453	322	374	483	336	381	483
10%		378	429	460	378	434	460	360	424	480	360	421	509	365	434	509
50%		407	497	536	407	505	536	409	495	536	408	491	561	413	501	561
90%		456	578	635	456	586	635	454	577	635	448	572	635	471	582	637
End point		490	630	706	511	639	706	496	627	706	498	618	700	507	628	700

From Shelton, E. M., "Diesel Fuel Oils, 1979," Report No. BETC/PPS-79/5, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 13
BERC-API SURVEY OF TYPE R-R (RAILROAD) FUELS
(2 No. 1-D, 100 No. 2-D, and 2 No. 4-D Fuels)

Diesel fuel survey, 1979

Geographic distribution of diesel fuels		Eastern region			Southern region			Central region			Rocky Mountain region			Western region		
Districts within region		A,B,C			D			E,F,G			H,I,J,K			L,M,N,O,P		
Additional districts		D,E,F,G,J			A,B,C,E,F,G,I,J			A,B,C,D,I,J			C,D,E,F,G,L,M,N,O,P			G,H,I,K		
Number of fuels		28			18			27			18			11		
Test	ASTM	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	25.8	34.7	43.6	29.3	33.6	36 2	29.3	34.5	41.4	28.5	34.1	41.4	28.5	33.9	36.1
Flash point, °F	D93	144	-	194	144	-	192	132	-	166	138	-	206	164	-	212
Color, ASTM	D1500	0.5	-	L3.0	0.5	-	L3.0	L0.5	-	2.0	0.0	-	1.5	0.5	-	L2.0
Viscosity at 100° F:																
Kinematic, cs	D445	2.05	2.91	5.02	2.26	2.84	3.40	1.81	2.66	3.34	1.81	2.77	3.60	1.99	2.95	3.60
Saybolt Universal, sec.	D88	32.8	35.7	42.5	33.5	35.4	37.3	32.0	34.8	37.1	32.0	35.2	37.9	32.6	35.8	37.9
Cloud point, °F	D2500	-2	-	30	0	-	18	-30	-	18	-30	-	22	-2	-	22
Pour point, °F	D97	-40	-	20	-40	-	0	-40	-	5	-30	-	20	-10	-	20
Sulfur content, wt%	D129	0.03	0.21	0.65	0.06	0.23	0.65	0.13	0.271	0.65	0.06	0.380	0.61	0.06	0.297	0.61
Aniline point, °F	D611	117.0	138.9	167	117.0	138.3	155.0	117.0	141.1	156	112.0	135.5	145.5	115.0	138.2	146
Carbon residue on 10%, wt%	D524	0.015	0.117	0.19	0.015	0.120	0.31	0.056	0.148	0.34	0.04	0.135	0.34	0.070	0.104	0.15
Ash, wt%	D482	0.000	0.001	0.007	0.000	0.001	0.007	0.000	0.0006	0.003	0.000	0.0010	0.007	0.000	0.003	0.01
Cetane number	D613	36	44.1	54.0	36	42.5	50.8	36	43.0	50.8	41	45.3	50	36	45.3	51.0
Cetane index	D975	43.2	53.6	68.1	39.3	46.9	54.6	39.3	47.6	54.6	39.3	45.4	53.5	-	-	46.6
Distillation temp, °F																
volume recovered:	D86															
IBP		344	385	512	344	380	416	331	372	420	340	382	420	363	386	408
10%		404	439	530	404	435	456	380	427	468	360	432	478	412	444	478
50%		452	506	562	452	505	534	441	501	534	441	504	534	461	511	533
90%		522	590	618	522	588	616	487	589	674	487	586	631	575	596	619
End point		584	642	680	598	645	680	522	640	670	522	632	680	621	641	660

From Shelton, E. M., "Diesel Fuel Oils, 1979," Report No. BETC/PPS-79/5, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 14
BERC-API SURVEY OF TYPE S-M (STATIONARY AND MARINE) FUELS
(1 No. 1-D and 10 No. 2-D Fuels)

Diesel fuel survey, 1979

Geographic distribution of diesel fuels		Eastern region	Southern region			Central region			Rocky Mountain region	Western region		
Districts within region		A,B,C	D			E,F,G			H,I,J,K	L,M,N,O,P		
Additional districts		E,F,G				C						
Number of fuels		1	4			3			-	3		
Test	ASTM	(1 fuel)	Minimum	Average	Maximum	Minimum	Average	Maximum	(No Analyses)	Minimum	Average	Maximum
Gravity, °API	D287	-	23.8	29.6	39.1	33.0	34.9	37.8	-	33.4	38.3	47.1
Flash point, °F	D93	-	152	-	254	146	-	158	-	120	-	212
Color, ASTM	D1500	-	L0.5	-	1.0	1.5	-	L2.0	-	0.5	-	L0.5
Viscosity at 100° F:												
Kinematic, cs	D445	-	2.40	7.02	20.1	2.37	2.59	2.70	-	1.43	3.01	4.0
Saybolt Universal, sec.	D88	-	34.0	48.9	98.2	33.9	34.6	35.0	-	-	36.0	39.2
Cloud point, °F	D2500	-	6	-	10	-2	-	2	-	-6	-	46
Pour point, °F	D97	-	-10	-	65	-15	-	0	-	-10	-	10
Sulfur content, wt%	D129	-	0.13	0.72	2.45	0.26	0.28	0.30	-	0.02	0.10	0.17
Aniline point, °F	D611	-	103	116	129	133.0	144.0	155.0	-	-	-	-
Carbon residue:	D524											
on 10%, wt%		-	0.014	0.050	0.068	-	-	0.13	-	0.03	0.06	0.10
on 100%, wt%		-	-	-	0.39	-	-	-	-	-	-	-
Ash, wt%	D482	-	0.000	0.001	0.002	0.000	0.0007	0.001	-	0.0000	0.0003	0.001
Cetane number	D613	-	32.3	35.4	40.4	-	-	-	-	-	-	49
Cetane index	D975	-	-	-	54.4	43.2	46.6	53.2	-	53.1	54.8	56.5
Distillation temp, °F												
volume recovered:	D86											
IBP		-	370	395	418	358	366	370	-	-	-	390
10%		-	416	446	478	419	421	424	-	359	435	478
50%		-	494	510	530	493	498	503	-	412	498	550
90%		-	575	594	604	580	585	590	-	486	580	635
End point		-	635	[illegible]	662	618	635	645	-	521	621	690

From Shelton, E. M., "Diesel Fuel Oils, 1979," Report No. BETC/PPS-79/5, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 15
BERC-API SURVEY OF JP-4 MILITARY AVIATION TURBINE FUELS
(Also qualify as D2880 Grade 0-GT Gas Turbine Fuel Oils)

	1970	1971	1972	1973	1974	1975	1976	1977	1978
Number of fuels	33	32	35	30	33	30	33	28	23
Gravity, °API	53.8	54.5	54.6	54.1	54.3	54.0	54.1	53.9	53.9
Distillation 1/									
Temperature:									
10% recovered, °F............	212	211	215	216	214	211	215	211	209
50% do. , °F............	290	288	285	289	291	287	292	299	289
90% do. , °F............	389	393	394	402	397	390	399	395	400
Recovered at 400 F, %	89.5	89.4	87.5	84.0	85.9	86.0	85.6	85.7	86.2
Reid vapor pressure, lb	2.6	2.6	2.5	2.5	2.5	2.5	2.6	2.6	2.6
Freezing point, °F	<-76	<-76	-84	-80	-81	-84	-84	-79	-79
Viscosity, kinematic, -30 F, cs.....	2.80	2.94	3.01	2.83	2.68	2.20	2/2.4	4/ 2.4	-
Aniline point, °F	129.4	130.4	130.7	132.0	132.8	129.9	131.3	130.8	130.3
Aniline-gravity constant, No.......	6,961	7,107	7,136	7,141	7,211	7,028	7,103	7,061	7,049
Water tolerance, ml...............	0.1	0.2	0.4	0.6	0.5	0.5	0.6	0.3	0.6
Sulfur:									
Total, wt %....................	0.032	0.034	0.032	0.033	0.035	0.036	0.042	0.044	0.035
Mercaptan, wt %	0.0005	0.0006	0.0005	0.0005	0.0012	0.0006	0.0005	0.0004	0.0004
Naphthalenes, wt %	1.45	0.88	0.74	0.9	1.3	0.20	2/ .51	4/ 0.2	-
Aromatic content, vol %...........	11.5	10.8	10.7	11.8	10.6	11.2	11.2	12.2	12.3
Olefin content, vol %.............	0.9	0.8	0.9	1.0	0.9	1.0	0.9	0.8	0.8
Smoke point, mm	27.6	27.4	28.0	28.2	28.1	27.2	27.7	27.7	27.5
Smoke volatility index.............	65.2	65.0	64.9	63.2	64.3	62.8	63.6	63.5	63.5
Gum, mg/100 ml:									
Existent, at 450 F...............	0.6	0.6	0.7	0.6	0.8	0.9	0.7	0.7	0.7
Potential, at 212 F..............	1.2	1.2	1.1	1.2	1.2	1.0	1.0	1.0	1.2
Heat of combustion, net, Btu/lb	18,708	18,721	18,725	18,727	18,733	18,714	18,721	18,715	18,716
Luminometer number...............	63	60	63	64	62	62	3/ 61	5/ 61	-
Thermal stability:									
Pressure drop, in. Hg............	0.17	0.12	0.06	0.22	0.15	0.26	0.30	0.5	0.2
Water separometer index, No.......	88	88	90	90	91	90	91	90	91

1/ Distillation data reported on evaporated basis prior to 1972.
2/ Represents two samples.
3/ Represents four samples.
4/ Represents one sample.
5/ Represents three samples.

From Shelton, E. M., "Aviation Turbine Fuels, 1979," Report No. BETC/PPS-79/2, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 16
BERC-API SURVEY OF JP-5 MILITARY AVIATION TURBINE FUELS
(Also qualify as D2880 Grade 1-GT Gas Turbine Fuel Oils)

	1970	1971	1972	1973	1974	1975	1976	1977	1978
Number of fuels	10	10	12	8	7	8	8	7	7
Gravity, °API	41.0	42.0	41.6	41.7	41.6	41.5	41.5	41.4	41.7
Distillation 1/									
Temperature:									
10% recovered, °F	383	380	388	387	389	388	390	385	390
50% do. , °F	416	414	419	422	419	418	422	420	419
90% do. , °F	461	459	460	469	462	462	470	470	465
Recovered at 400 F, %	31.5	36.2	25.0	23.4	23.2	25.9	21.6	24.1	23.6
Reid vapor pressure, lb	-	-	-	-	-	-	-	-	-
Freezing point, °F	-58	-57	-59	-56	-58	-56	-54	-56	-55
Viscosity, kinematic, -30 F, cs.	10.2	10.2	10.1	10.5	10.5	9.0	10.2	9.7	7.1
Aniline point, °F	140.0	140.8	139.7	144.6	144.0	142.1	143.3	143.0	142.9
Aniline-gravity constant, No.	5,740	5,914	5,714	6,059	5,990	5,840	5,971	5,920	5,959
Water tolerance, ml	0.2	0.03	-	-	0.1	0.1	0.3	3/ 0.0	0.5
Sulfur:									
Total, wt %	0.045	0.053	0.037	0.096	0.065	0.061	0.059	0.068	0.057
Mercaptan, wt %	0.0004	0.0003	0.0009	0.0007	0.0015	0.0006	0.0004	0.0006	0.0004
Naphthalenes, wt %	-	-	1.21	-	-	-	-	2/ 1.0	-
Aromatic content, vol %	15.9	16.4	15.7	16.0	16.0	15.2	16.9	16.0	15.3
Olefin content, vol %	1.0	1.1	0.6	0.8	1.0	1.2	0.8	0.9	1.4
Smoke point, mm	22.4	22.2	21.7	22.2	22.3	22.9	22.3	22.6	21.8
Smoke volatility index	35.6	37.4	32.2	32.0	32.0	33.8	31.4	32.7	31.4
Gum, mg/100 ml:									
Existent, at 450 F	0.5	0.9	1.3	1.3	0.6	1.0	0.8	1.1	1.0
Potential, at 212 F	2.2	2.7	2.2	2.6	-	-	2/ 1.0	2/ 1.0	-
Heat of combustion, net, Btu/lb	18,514	18,534	18,515	18,526	18,539	18,522	18,538	18,533	18,535
Luminometer number	44	-	-	-	-	-	2/ 48	2/ 48	-
Thermal stability:									
Pressure drop in. Hg	0.01	0.08	0.14	0.5	0.2	0.16	0.16	0.4	0.3
Water separometer index, No.	95	97	96	94	95	94	92	96	95

1/ Distillation data reported on evaporated basis prior to 1972.

2/ Represents one sample.

3/ Represents two samples.

From Shelton, E. M., "Aviation Turbine Fuels, 1979," Report No. BETC/PPS-79/2, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 17
BERC-API SURVEY OF JET A COMMERCIAL JET FUELS
(Also qualify as D2880 Grade 1-GT Gas Turbine Fuel Oils)

	1970	1971	1972	1973	1974	1975	1976	1977	1978
Number of fuels	57	57	64	65	63	66	65	65	60
Gravity, °API	42.7	42.8	43.0	42.9	42.9	42.9	43.1	43.2	42.9
Distillation 1/									
Temperature:									
10% recovered, °F	371	371	372	369	369	370	371	370	374
50% do. , °F	417	416	415	415	413	414	415	414	416
90% do. , °F	477	473	474	473	472	472	474	472	473
Recovered at 400 F, %	34.2	35.6	35.7	36.3	37.2	36.8	35.3	37.6	33.9
Reid vapor pressure, lb	0.3	0.2	0.2	0.1	-	0.2	0.2	0.2	-
Freezing point, °F	-50	-50	-50	-51	-51	-50	-51	-50	-49
Viscosity, kinematic, -30 F, cs	9.45	9.45	9.38	9.12	9.21	9.22	9.32	9.4	9.2
Aniline point, °F	144.4	144.1	144.8	143.2	142.6	143.4	144.2	143.6	143.6
Aniline-gravity constant, No.	6,166	6,182	6,241	6,143	6,118	6,152	6,244	6,204	6,160
Water tolerance, ml	0.2	0.2	0.3	0.5	0.5	0.4	0.5	0.3	0.4
Sulfur:									
Total, wt %	0.049	0.045	0.048	0.045	0.054	0.054	0.060	0.061	0.053
Mercaptan, wt %	0.0005	0.0006	0.0004	0.0006	0.0009	0.0008	0.0009	0.0008	0.0007
Naphthalenes, wt %	1.91	1.85	1.79	1.80	1.82	1.67	1.70	1.70	1.78
Aromatic content, vol %	16.4	16.1	16.1	16.3	16.7	16.9	17.0	17.2	17.4
Olefin content, vol %	1.1	1.0	1.1	1.2	1.2	1.0	1.1	1.2	1.0
Smoke point, mm	23.3	23.4	23.2	23.3	22.9	22.9	23.1	23.1	22.7
Smoke volatility index	37.7	38.4	37.5	38.5	38.6	38.2	37.9	38.8	36.8
Gum, mg/100 ml:									
Existent, at 450 F	0.6	0.7	0.8	0.7	0.8	0.9	0.8	0.9	0.8
Potential, at 212 F	1.5	1.4	1.6	1.6	1.9	1.9	2.2	1.5	2.3
Heat of combustion, net, Btu/lb	18,586	18,584	18,589	18,583	18,582	18,622	18,609	18,589	18,584
Luminometer number	48.9	49	50	49	50	50	50	50	49
Thermal stability:									
Pressure drop, in. Hg	0.18	0.21	0.23	0.35	0.33	0.26	0.29	0.3	0.4
Water separometer index, No.	95	96	96	95	95	95	96	94	95

1/ Distillation data reported on evaporated basis prior to 1972.

From Shelton, E. M., "Aviation Turbine Fuels, 1979," Report No. BETC/PPS-79/2, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API)."

TABLE 18

SULFUR AND NITROGEN CONTENTS OF CRUDE OILS

Selected from Representative Fields

FIELD AND CRUDE	GRAVITY °API	SULFUR %	NITROGEN %
Arkansas-Schuler	33.2	1.54	.063
California-Elk Hills	23.1	.69	.46
California-Midway-Sunset	20.3	.88	.58
California-Santa Maria	16.0	5.06	.63
California-Wilmington	25.6	1.24	.58
Colorado-Rangely	35.2	.73	.063
Illinois-Louden	38.8	.26	.094
Kansas-Kraft Prusa	43.0	.27	.17
Louisiana-Delta Farms	33.8	.22	.055
Michigan-Deep River	34.2	.60	.12
Mississippi-Baxterville	15.0	3.07	.19
Mississippi-Brookhaven	26.6	.86	.066
Montana-Cut Bank	46.5	.38	.018
New Mexico-Langlie	34.8	1.35	.066
Oklahoma-Burbank	35.8	.21	.05
Oklahoma-Velma	28.2	.81	.27
Texas-East Texas	37.8	.36	.085
Texas-Hastings	31.3	.24	.034
Texas-Hawkins	25.7	2.45	.13
Texas-Seeligson	40.9	.10	.004
Texas-Wasson	34.2	1.90	.10
Wyoming-Elk Basin	31.5	1.72	.14
Wyoming-Oregon Basin	22.0	3.27	.35
Foreign-Iran	36.0	1.36	.14
Iraq	36.6	1.93	.094
Bitumens, Natural			
California-Edna	4.3	3.20	1.23
Utah-Vernal	8.6	.50	1.18
Canada-Athabaska	13.0	5.15	.43

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TABLE 19

NITROGEN CONTENTS OF CRUDE OILS AND FRACTIONS

CRUDE OIL	NITROGEN CONTENT BASIC %	TOTAL %	RATIO B/T
Jackson	.01	.04	.25
Mirando	.01	.04	.25
Scurry County	.02	.06	.33
East Texas	.02	.08	.25
West Texas	.03	.11	.27
Kansas	.04	.12	.33
Midcontinent Mix	.025	.10	.25
Santa Maria Valley	.19	.66	.29
Kettleman Hills	.14	.41	.34
Wilmington	.14	.50	.28
Ventura	.13	.42	.31
Tibu	.033	.13	.25
Gulco Guario	.02	.08	.25
Kuwait	.03	.12	.25
Wilmington Residuum	.34	1.13	.30
Asphaltene fraction	.69	2.33	.30
Pentane Sol. fraction	.26	.87	.30
Kuwait Residuum	.09	.35	.26
Asphaltene fraction	.24	.91	.26
Pentane Sol. fraction	.08	.28	.29
DISTILLATES		(Expressed in ppm)	
California Naphtha	3.7	7.3	.51
Penn. S. R. Gasoline	3.2	15.0	.47
Michigan S. R. Gasoline	2.0	5.0	.40
Kuwait Naphtha		3.1	
Wyoming Naphtha	1.8	4.6	.39
Calif. cracked naphtha	171	184	.92
Calif. thermal cracked	224	234	.96
Calif. (Sta. Maria) coker dist.	62	130	.45
Calif. thermal No. 2 fuel	22	56	.39
Wyoming cat. No. 2 fuel	61	210	.29
Midcont. thermal No. 2 fuel	161	224	.72

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TABLE 20

TYPICAL NO. 2 FUELS

Description	West Coast Blend[d]	Virgin Distillate "Premium" Diesel Fuel, Gulf Coast	Hydrogenated Blend of Virgin & FCC[c] Distill. Gulf Coast	Unusual Severely Hydrogenated Gulf Coast Condensate	Virgin Distillate "Premium" Diesel Fuel, East Coast
Inspection					
Gravity: °API	38.0	39.1	35.0	41.7	37.6
Specific Gravity, 60°/60°F.	0.8348	0.8294	0.8499	0.8170	0.8368
Viscosity, SUV: Sec. 100°F.	35.5	33.6	34.7	34.0	34.6
Flash, P-M: °F.	176	156	156	152	172
Cloud Point: °F.	+4	-6	-4	0	-18
Pour Point: °F.	+5	-20	-10	-10	-20
Appearance	bright	bright	bright	bright	bright
Color, ASTM D 1500	L 1.0	L 0.5	L 1.0	L 0.5	L 0.5
Odor	oxidized	normal	normal	normal	normal
Sulfur: % by Wt.	0.40	0.04	0.12	0.05	0.05
Water: PPM	80	134	26	11	50
Carbon Residue, Rams. on 10% Bottoms: % by Wt.	0.09	0.05	0.13	0.05	0.02
Aniline Point: °F.	157.0	154.5	144.5	165.0	153.4
Hydrocarbon-Type Analyses[a] % by Volume					
Paraffins	43.8	36.3	35.4	48.5	33.0
Cycloparaffins	30.2	42.7	29.7	34.4	43.2
1 Ring	19.9	30.3	21.9	27.6	29.6
2 Ring	8.6	9.3	6.5	5.8	11.1
3 Ring	1.7	2.7	1.3	1.0	2.5
4 Ring	0.0	0.4	0.0	0.0	0.0
Olefins	1.0	1.0	2.0	1.5	2.0
Aromatics[b]	25.0	20.0	32.9	15.6	21.8
Benzenes	12	11	17	11	12
Indanes	6	5	7	3	6
Indenes	4	1	2	1	2
Naphthalenes	1	3	6	1	2
Acenaphthenes	1	0	1	0	0
Acenaphthylenes	1	0	0	0	0
Cetane Index	54.8	51.8	48.0	57.0	50.7
Distillation, ASTM D 86					
Over Point: °F.	392	376	376	358	373
End Point: °F.	631	610	636	626	615
10% Condensed at: °F.	419	410	430	410	424
50	511	478	506	478	490
90	600	570	586	572	567
Recovery: %	99.0	98.0	98.0	99.0	98.0
Residue: %	1.0	1.0	1.0	1.0	1.0
Loss: %	0.0	1.0	1.0	0.0	1.0

a. Combined FIA and high molecular weight mass analyses.
b. Aromatic-Type data is accurate to ±2%.
c. Fluid cat-cracked
d. Virgin and hydrocracked distillate

GR&DC
PTD
Harmarville, Pa.
RWR/lr

TABLE 21

THERMAL PROPERTIES OF PETROLEUM PRODUCTS

TABLE 6.—*Heats of combustion of crude oils, fuel oils, and kerosenes*

Gravity		Density	Total heat of combustion at constant volume, Q_v			Net heat of combustion at constant pressure, Q_p			Degrees A. P. I. at 60° F.
Degrees A. P. I. at 60° F.	Specific at 60°/60° F.	Pounds per gallon	Cal./g	Btu./lb.	Btu./gal.	Cal./g	Btu./lb.	Btu./gal.	
10	1.0000	8.337	10,300	18,540	154,600	9,740	17,540	146,200	10
11	.9930	8.279	10,330	18,590	153,900	9,770	17,580	145,600	11
12	.9861	8.221	10,360	18,640	153,300	9,790	17,620	144,900	12
13	.9792	8.164	10,390	18,690	152,600	9,810	17,670	144,200	13
14	.9725	8.108	10,410	18,740	152,000	9,840	17,710	143,600	14
15	.9659	8.053	10,440	18,790	151,300	9,860	17,750	142,900	15
16	.9593	7.998	10,470	18,840	150,700	9,880	17,790	142,300	16
17	.9529	7.944	10,490	18,890	150,000	9,900	17,820	141,600	17
18	.9465	7.891	10,520	18,930	149,400	9,920	17,860	140,900	18
19	.9402	7.839	10,540	18,980	148,800	9,940	17,900	140,300	19
20	.9340	7.787	10,570	19,020	148,100	9,960	17,930	139,600	20
21	.9279	7.736	10,590	19,060	147,500	9,980	17,960	139,000	21
22	.9218	7.686	10,620	19,110	146,800	10,000	18,000	138,300	22
23	.9159	7.636	10,640	19,150	146,200	10,020	18,030	137,700	23
24	.9100	7.587	10,660	19,190	145,600	10,040	18,070	137,100	24
25	.9042	7.538	10,680	19,230	145,000	10,050	18,100	136,400	25
26	.8984	7.490	10,710	19,270	144,300	10,070	18,130	135,800	26
27	.8927	7.443	10,730	19,310	143,700	10,090	18,160	135,200	27
28	.8871	7.396	10,750	19,350	143,100	10,110	18,190	134,600	28
29	.8816	7.350	10,770	19,380	142,500	10,120	18,220	133,900	29
30	.8762	7.305	10,790	19,420	141,800	10,140	18,250	133,300	30
31	.8708	7.260	10,810	19,450	141,200	10,150	18,280	132,700	31
32	.8654	7.215	10,830	19,490	140,600	10,170	18,310	132,100	32
33	.8602	7.171	10,850	19,520	140,000	10,180	18,330	131,500	33
34	.8550	7.128	10,860	19,560	139,400	10,200	18,360	130,900	34
35	.8498	7.085	10,880	19,590	138,800	10,210	18,390	130,300	35
36	.8448	7.043	10,900	19,620	138,200	10,230	18,410	129,700	36
37	.8398	7.001	10,920	19,650	137,600	10,240	18,430	129,100	37
38	.8348	6.960	10,940	19,680	137,000	10,260	18,460	128,500	38
39	.8299	6.920	10,950	19,720	136,400	10,270	18,480	127,900	39
40	.8251	6.879	10,970	19,750	135,800	10,280	18,510	127,300	40
41	.8203	6.839	10,990	19,780	135,200	10,300	18,530	126,700	41
42	.8155	6.799	11,000	19,810	134,700	10,310	18,560	126,200	42
43	.8109	6.760	11,020	19,830	134,100	10,320	18,580	125,600	43
44	.8063	6.722	11,030	19,860	133,500	10,330	18,600	125,000	44
45	.8017	6.684	11,050	19,890	132,900	10,340	18,620	124,400	45
46	.7972	6.646	11,070	19,920	132,400	10,360	18,640	123,900	46
47	.7927	6.609	11,080	19,940	131,900	10,370	18,660	123,300	47
48	.7883	6.572	11,100	19,970	131,200	10,380	18,680	122,800	48
49	.7839	6.536	11,110	20,000	130,700	10,390	18,700	122,200	49

The heats of combustion of petroleum oils containing appreciable amounts of foreign matter may be estimated by means of the following relations:

$$\overline{Q}_v = Q_v - 0.01\, Q_v(\%\ \mathrm{H_2O} + \%\ \mathrm{ash}\ + \%\ \mathrm{S}) + X(\%\ \mathrm{S})$$

$$\overline{Q}_p = Q_p - 0.01\, Q_p(\%\ \mathrm{H_2O} + \%\ \mathrm{ash}\ + \%\ \mathrm{S}) + X(\%\ \mathrm{S}) - Y(\%\ \mathrm{H_2O})$$

taking values of Q_v and Q_p from Table 6 in the particular units desired, corresponding to the gravity of the oil and values of X and Y in the desired units from the following:

Units	X	Y
Cal/g	22.5	5.85
Btu./lb.	40.5	10.53
Btu./gal.	338 d	87.8 d

-From Miscellaneous Publication of the Bureau of Standards, No. 97, "Thermal Properties of Petroleum Products", Nov. 9, 1929

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OF POOR QUALITY

TABLE 22

DETAILED INSPECTION OF FIVE KEROSENE SAMPLES

Refinery	Midwest	East Coast	Gulf Coast	Great Lakes	Gulf Coast No. 2
Inspection:					
Gravity: °API	43.7	40.6	42.3	42.1	41.5
Average Molecular Wt. (Calc.)[a]	176	172	173	176	179
Viscosity, S Thermo V					
Gulf 47: 60°F	370	395	370	375	405
Viscosity, Kin.: Cs,					
-30°F	9.59	10.87	9.92	9.95	11.84
-20	7.60	8.60	8.52	8.57	9.20
0	5.20	5.76	5.30	5.37	6.10
60	3.34	3.45	2.31	2.33	2.52
100	1.56	1.65	1.56	1.60	1.70
Flash, TCC: °F	140	142	136	138	136
Flash, P-M: °F	146	144	140	140	138
Cloud: °F	-48	-48	-50	-46	-56
Pour: °F	-50	-50	-55	-50	-60
Resistivity, ASTM D 1169					
Ohm-Cmx10^{12}					
77°F	50	134	235	11.7	101
Conductivity, Calculated: Conductivity Units	2	0.7	0.4	9	1
Freezing Point, ASTM D 2386: °F	-41	-45	-46	-42	-54
Surface Tension, ASTM D 1331: Dynes/Cm	28	28	28	28	28
IFT° ASTM D 971: Dynes/Cm	51	49	49	48	51
Appearance	Bright	Bright	Bright	Bright	Bright
Color, Saybolt	+30	+30	+30	+30	+30
Color, Lovibond 18" Cell, IP-17	0.25	0.50	0.50	0.50	0.25
Doctor, FTMS 791-5203	Negative	Negative	Negative	Negative	Negative
Chlorine PPM	< 1	< 1	< 1	< 1	< 1
Elements in Liquid Hydrocarbons: PPM					
Atomic Absorption					
Barium	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Calcium	0.1	< 0.1	0.2	0.1	< 0.1
Chromium	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Copper	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02
Iron	0.2	< 0.1	0.1	< 0.1	< 0.1
Potassium	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Sodium	< 0.1	< 0.1	< 0.1	0.1	0.1
Zinc	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Lead, PPB	254	86	<20	20	<20
Nickel, PPM	0.04	0.04	0.12	0.03	0.04
Vanadium, PPM	< 0.02	< 0.02	< 0.02	< 0.02	< 0.02
Hydrogen, % by Wt.	13.56	13.34	13.45	13.58	13.54
Nitrogen, PPM	1.0	5.8	2.7	4.5	1.6
Nitrogen, Basic, PPM	0.7	5.0	2.2	3.4	1.2
Oxygen, Total, PPM	256	100	300	170	<100
Sulfur, ASTM D 1266: %	0.004	0.016	0.056	0.080	0.008
Disulfide Sulfur, PPM	<10	<10	<10	220	<10
Elemental Sulfr, PPM	< 5	< 5	< 5	33	< 5
Hydrogen Sulfide, PPM	<10	<10	<10	<10	<10
Mercaptan Sulfur, ASTM D 1323: PPM	< 3	< 3	< 3	< 3	< 3
Water, PPM	47	26	37	53	35
Particulate Matter, ASTM D 2276					
Mg/Gal.	1.2	< 1	< 1	1.4	1.8
Carbon Residue, Rams, on 10% Btms.: %	0.05	0.07	0.07	0.06	0.06
Copper Strip, ASTM D 130, 212°F, 3 Hr.	1	1	1	4	1
Silver Strip, ASTM D 130 Mod., 212°F, 3 Hr.	1	1	1	4	1
Silver Corrosion, ASTM D 1616 Mod.	1	1	1	4	1
Neutralization No., ASTM D 974 Mod.[b]					
Total Acid Number	0.010	0.010	0.010	0.020	0.020
Nap. Acids, Mg.KOH/G	0.004	0.002	0.003	0.006	0.002
Phenols, % by Wt.	< 0.001	0.001	0.004	0.013	< 0.001
Thiophenols, % by Wt.	< 0.001	< 0.001	< 0.001	0.001	< 0.001
Existent Gum: Mg/100 Ml	< 1	< 1	< 1	1	< 1
Potential Gum, 16 Hr.: Mg/100 Ml	1	< 1	< 1	2	1
Aniline Point, ASTM D 611: °F	146.5	139.4	142.0	143.0	146.0
Aniline Gravity Product	6,402	5,660	6,007	6,020	6,059
Heat of Combustion, ASTM D 1405					
BTU/Lb Net	18,618	18,533	18,567	18,549	18,582
BTU/Gal Net	125,187	126,877	125,866	125,874	126,543
Total Heat of Combustion[d]					
BTU/Gal Gross	134,676	135,422	134,420	134,554	134,844
Hydrocarbon Types, ASTM D 1319					
Aromatics	16.0	17.0	17.0	18.0	15.0
Olefins	1.0	1.0	0.5	1.5	1.0
Saturates	83.0	82.0	82.5	80.5	84.0
Naphthenes: % by Vol.	35.4	37.0	31.0	37.1	37.8
Napthalenes, ASTM D 1840: % by Vol.	1.14	1.32	1.50	2.00	0.71
Cetane No., D 613	48	43	44	48	44
Cetane Index	51	45	48	48	48
Thermal Stability, ASTM D 1660					
Preheater Temperature	300	300	300	300	300
Filter Temperature	400	400	400	400	400
Fuel Flow Rate: Lb/Hr	6	6	6	6	6
Preheater Deposit Rating	0	0	0	0	0
Filter Pressure Drop	< 0.1	0.1	< 0.1	0.1	< 0.1
Test Time: Minutes	300	300	300	300	300
Water Reaction, FTMS 791-3251					
Volume Change: Ml	0	0	0	0	0
Rating	1	1	1	1	1
Water Separation Index Mod.					
ASTM D 2550	94	90	84	82	90
Smoke Point, ASTM D 1322: Mm	25	21	23	24	24
Luminometer No., ASTM D 1740	47	41	50	50	52
Distillation, ASTM D 86					
Over Point: °F	349	348	352	346	341
End Point: °F	493	542	523	524	524
5% Evap. @ °F	367	375	367	376	374
10	376	385	375	385	384
20	390	391	387	397	402
30	400	401	397	408	414
40	412	410	408	416	424
50	422	419	419	426	432
60	433	431	432	434	442
70	443	444	446	446	452
80	453	460	463	459	466
90	468	483	483	478	484
95	478	502	498	490	496
Recovery: %	98.3	98.8	98.7	99.0	99.0
Residue: %	1.6	1.2	1.3	1.0	-
Loss: %	0.1	-	-	-	-

a. From correlation based on API gravity and 50% distillation point.
b. 100 G Sample.
c. Silver strip suspended 50% in liquid phase at start of distillation.
d. Calculated from API Gravity and Sulfur Content per Bureau of Standards Misc. Publication No. 97. This is the "Heat Content" normally used in U.S.A. in furnace and boiler calculations.

RCA:kdl
GS&TC - ATD
Harmarville, PA

TABLE 23
DETAILED INSPECTION OF FIVE NO. 2 FUEL OILS

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Refinery	Midwest	East Coast	Gulf Coast	Great Lakes	Gulf Coast No. 2
Inspection:					
Gravity: °API	34.9	34.1	34.8	37.8	35.1
Average Molecular Wt. (Calc.)[a]	202	204	207	220	222
Viscosity, Kin. Cs.					
32°F.	5.92	6.88	7.25	7.49	8.85
77	3.06	3.40	3.78	3.68	4.15
100	2.36	2.61	2.72	2.79	3.11
Viscosity, SUV: Sec.					
32°F.	45.1	48.2	49.4	50.2	54.7
77	36.2	37.3	38.8	38.2	39.7
100	33.9	34.7	35.0	35.3	36.3
Flash, TCC: °F.	150	150	160	158	156
Flash, P-M: °F.	158	156	166	162	158
Cloud: °F.	+2	+10	+2	+6	+2
Pour: °F.	-5	+5	-5	0	-10
Color, ASTM D 1500	L 0.5	L 1.0	L 1.0	L 1.0	L 1.0
Appearance	bright	bright	bright	bright	bright
Doctor, FTMS 5203	negative	negative	negative	negative	negative
Ash, ASTM D 482: %	0.001	0.002	0.001	0.002	0.002
Elements in Liquid Hydrocarbons: ppm					
Atomic Absorption					
Barium	3.1	5.5	< 0.1	5.0	< 0.1
Calcium	0.2	0.7	< 0.1	0.1	0.1
Chromium	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Copper	0.04	< 0.02	0.04	0.02	< 0.02
Iron	0.2	0.3	0.1	< 0.1	< 0.1
Potassium	0.5	< 0.1	< 0.1	< 0.1	< 0.1
Sodium	0.5	0.2	0.1	0.3	0.5
Zinc	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
Phosphorus, PPB	< 2	< 2	< 2	< 2	< 2
Lead, PPB	175	< 20	< 20	40	85
Vanadium, PPM	0.02	0.09	< 0.02	0.03	< 0.02
Nickel, PPM	0.03	0.06	0.04	0.04	0.02
Ultimate Analysis					
Carbon, %	87.22	87.15	86.90	86.56	86.76
Hydrogen, %	12.53	12.79	12.97	13.19	13.04
Nitrogen, PPM	84	98	129	49	25
Oxygen, Total, PPM	512	670	850	570	550
Basic Nitrogen, PPM	29	48	61	24	13
Ammonia, PPM	5	1	13	< 1	< 1
Sulfur, ASTM D 1266: %	0.12	0.08	0.20	0.18	0.09
Disulfide Sulfur, PPM	< 10	< 10	20	80	< 10
Elemental Sulfur, PPM	< 5	< 5	< 5	8	< 5
Hydrogen Sulfide, PPM	< 10	< 10	< 10	< 10	< 10
Mercaptan Sulfur, ASTM D 1323: %	0.0036	0.0012	0.0016	0.0036	0.0003
Chlorine PPM	< 1	< 1	< 1	< 1	< 1
Water and Sediment, ASTM D 2709: %	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
Water, PPM	58	42	59	61	51
Carbon Residue, Rams., on 10% Btms.: %	0.07	0.13	0.11	0.08	0.08
Copper Strip, 212°F., 3 Hr.	1	1	1	1	1
Silver Strip, 212°F., 3 Hr.	1	1	1	1	1
Aniline Point, ASTM D 611: °F	136.4	136.9	143.0	146.0	150.6
Aniline Gravity Product	4,760	4,668	4,976	5,519	5,286
Neutralization Value, ASTM D 974, Mod.[b]					
Total Acid Number	0.030	0.030	0.100	0.090	0.070
Neutrality, FTMS 5101	Neutral	Neutral	Neutral	Neutral	Neutral
Naphthenic Acids, MgKOH/g	0.020	0.020	0.080	0.071	0.062
Phenols, PPM	70	160	280	90	50
Thiophenols PPM	10	10	50	10	< 10
Existent Gum, ASTM D 381: Mg/100 Ml	2	5	2	5	2
Potential Gum, ASTM D 873: Mg/100 Ml.	5	6	3	7	4
Heat of Combustion, ASTM D 1405					
BTU/Lb. Net	18,425	18,417	18,434	18,498	18,482
BTU/Gal. Net	130,467	131,037	130,605	128,728	130,705
Heat of Combustion					
BTU/Lb. Net	18,277	18,293	18,286	18,443	18,396
BTU/Gal. Net	129,419	130,155	129,556	128,345	130,097
BTU/Lb. Gross	19,420	19,442	19,434	19,746	19,586
BTU/Gal. Gross	137,512	138,330	137,690	137,412	138,512
Total Heat of Combustion[d]					
BTU/Gal Gross	138,728	139,152	138,633	136,924	138,640
Hydrocarbon Types, ASTM D 1319: V %					
Aromatics	31.5	31.5	28.0	22.0	24.5
Olefins	1.0	1.0	1.0	1.0	1.0
Saturates	67.5	67.5	71.0	77.0	74.5
Naphthenes: V %	20.3	26.3	37.1	29.0	33.6
Naphthalenes, ASTM D 1840: V %	5.9	5.7	6.3	4.5	4.0
Luminometer No., ASTM D 1740	28	30	29	36	36
Smoke Point, ASTM D 1322: Mm.	14	14	14	20	18
Cetane Number, ASTM D 613	43	43	45	53	47
Cetane Index	46	45	47	54	51
Water Reaction, FTMS 3251					
Volume Change: Ml.	0	1	0	0	0
Interface Rating	2	2	1	1	1
Demulsification, MIL-F-16884F, 77°F.: Min.	8	8	2	7	3
Water Separation Index Mod., ASTM D 2550	10	6	14	6	12
Particulate Matter, ASTM D 2276					
Mg./Gal.	4.0	3.2	4.0	5.6	4.4
Millipore Rating	B-4	A-2	B-7	B-3	A-3
Accelerated Stability, ASTM D 2274					
Total Insolubles: Mg./100 Ml.	1.0	1.3	1.0	2.3	1.3
Resistivity, ASTM D 1169					
Ohm-Cmx10^{-12}					
77°F.	1.3	1.0	15.0	1.4	6.7
Conductivity Units (Calculated)	77	100	7	71	15
Thermal Stability: ASTM D 1660[c].					
Pressure Change: In. Hg	0.3	0.2	0.3	0.1	0.1
Tube Deposit Rating	1	1	1	1	1
Thermal Stability, ASTM D 1661					
Unwashed	1	1	1	1	1
Washed, Unwiped	1	1	1	1	1
Washed, Wiped	1	1	1	1	1
Tube Rating	1	1	1	1	1
Distillation, ASTM D 86					
Over Point: °F.	361	356	366	358	358
End Point: °F.	640	649	636	639	641
5% Evap at: °F.	402	397	404	413	408
10	419	418	412	435	438
20	440	448	436	460	469
30	457	465	454	478	488
40	475	480	471	498	505
50	492	496	502	512	524
60	511	512	514	527	543
70	532	533	534	543	560
80	555	556	558	560	580
90	586	591	594	584	600
95	612	617	615	601	619
Recovery: %	98.8	99.0	98.0	99.0	99.0
Residue: %	1.2	1.0	1.0	1.0	1.0
Loss: %	-	-	1.0	-	-

a. From correlation based on API gravity and 50% distillation point.
b. 100 Gram Sample.
c. Test Conditions
Preheater Temperature: 250°F.
Filter Temperature: 350°F.
Fuel Flow Rate: 6 Lb./Hr.
Test Time: 300 Minutes
d. Calculated from API Gravity and Sulfur Content per Bureau of Standards Misc. Publication No. 97. This is the "Heat Content" normally used in U.S.A. in furnace and boiler calculations.

GRADC-PED
Harmarville, PA
KWH/mes

TABLE 24

SURVEY OF TRACE METALS IN DISTILLATE FUELS[a]

(Includes field and refinery samples)

Fuel	No. of Samples	No. of Suppliers	Concentrations of Trace Metals: ppm						
			Na	K	V	Ca	Pb	Mg	Cu
Kerosene	151[b]	5	0.0-0.12	0.0-<0.10	0.0-<0.10	0.0-<1.0	0.0-3.0	0.0-<1.0	0.0-4.0
Diesel Fuel	152[c]	8	<0.01-1.0	<0.01-0.3	<0.01-<0.5	<0.01-<1.0	<0.01-<5.0	<0.01-<0.05	<0.01-1.0
Burner Fuel	82	5	0.0-6.4	0.0-1.2	0.0-0.7	0.0-<1.0	0.0-3.5	0.0-<0.01	0.002-0.42
Aviation Turbine Fuel	10	2	<0.02-<0.10	<0.02-<0.05	<0.01-<0.05	<0.02-<1.0	<0.05-<2.0	- -	<0.01-<0.10
Gas Turbine Fuel	13	-	<0.02-1.9	<0.02-0.33	<0.01-<0.10	<0.01-<0.20	<0.02-<2.0	<0.01-<0.1	<0.01-<0.10

[a] Abstracted from Ward, C. C., "Survey of Trace Metals in Distillate Fuels," ASTM Special Technical Publication 531, American Society for Testing and Materials, Philadelphia, PA 19103, 1972

[b] 128 of the samples showed only analyses for lead and copper.

[c] Includes 95 samples of Navy Fuel MIL-F-24397, a heavy distillate with an allowable maximum 95 percent distillation point of 765°F, which is consequently vulnerable to carryover of vanadium in the distillation.

TABLE 25
TRACE METALS IN GAS TURBINE FUELS
Delivered to Consolidated Edison Company of New York

A. *Metals content by supplier. Original study data (May to July, 1971).*

	Number of Samples	Method of Delivery	Metals Contents, ppm					
			Cu	V	Pb	Ca	Na	K
			Kerosine					
Supplier A	7	dedicated barge	0.03	0.04	0.14	0.20	0.67	0.19
Supplier C	6	truck	0.01	0.04	0.66	0.12	0.43	0.04
Supplier D	4	truck	0.02	0.05	0.47	0.15	0.36	0.19
Supplier L	1	truck	0.02	0.03	0.34	0.21	0.29	0.02
	Average, all barges		0.03	0.04	0.14	0.20	0.67	0.19
	Average, all trucks		0.01	0.04	0.56	0.14	0.38	0.10
			No. 2 Oil					
Supplier A	11	dedicated barge	0.02	0.03	0.08	0.22	0.67	0.14
	1	regular barge	0.01	0.03	0.17	0.13	0.27	0.12
	Supplier A, average		0.02	0.03	0.09	0.21	0.64	0.14
Supplier E	1	dedicated barge	0.02	< 0.03	0.26	0.08	0.42	0.03
	7	regular barge	0.02	0.03	0.37	0.14	0.51	0.04
	Supplier E, average		0.02	0.03	0.36	0.13	0.50	0.04
	Dedicated barge, average		0.02	0.03	0.09	0.21	0.65	0.13
	Regular barge, average		0.02	0.03	0.34	0.14	0.48	0.05
	Average, all barges		0.02	0.03	0.19	0.19	0.58	0.10
Supplier C	2	truck	0.06	0.04	0.35	0.38	0.33	0.03
Supplier H	2	truck	0.03	0.05	0.30	0.12	0.38	0.23
Supplier G	4	truck	0.08	0.10	0.26	0.16	0.81	0.08
	Average, all trucks		0.06	0.08	0.29	0.20	0.58	0.10

B. *Summary–metals content, May 1971 through March 1972.*

All Deliveries	Number of Samples	Cu	V	Pb	Ca	Na	K
Kerosine	161	0.02	0.03	0.42	0.12	0.41	0.04
No. 2 Oil	164	0.04	0.03	0.26	0.16	0.66	0.06

Abstracted from Del Favero, R., and Doyle, J. J.
"Experience with Distillate Fuels in Gas Turbines,"
ASTM Special Technical Publication 531, American
Society for Testing and Materials, Philadelphia, PA 19103, 1972.

TABLE 26

Summary of Grade 4 fuels

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region	Central region			Rocky Mountain region			Western region
Districts within region		A,B,C			D	E,F,G			H,I,J,K			L,M,N,O,P
Additional districts		E,F,G				C,I,J			G			
Number of fuels		4			-	3			5			-
Test	ASTM	Minimum	Average	Maximum	No Analyses	Minimum	Average	Maximum	Minimum	Average	Maximum	No Analyses
Gravity, °API	D287	18.9	22.3	29.4	-	18.9	20.0	21.2	15.5	19.7	29.5	-
Flash point, °F	D93	150	-	236	-	150	-	240	158	-	276	-
Viscosity at 100° F, cs	D445	8.26	17.26	34.1	-	11.7	14.0	15.3	14.4	18.2	23.4	-
Four point, °F	D97	-10	-	80	-	-10	-	65	-15	-	65	-
Sulfur content, wt%	D129	0.47	0.70	0.80	-	0.76	0.84	0.97	0.59	1.11	1.50	-
Carbon residue on 100%, wt%	D524	-	-	-	-	-	-	-	0.6	4.4	8.8	-
Ash, wt%	D482	0.0	0.012	0.02	-	0.015	0.018	0.02	0.016	0.019	0.02	-
Water and sediment, vol%	D1796	0.05	0.07	0.1	-	0.05	0.08	0.1	0.05	0.09	0.11	-
Gross Heat of Combustion Btu/gal		142,025	146,474	148,640	-	147,169	147,915	148,640	141,963	148,156	150,834	-

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 27

Summary of Grade 5 (light) fuels

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region	Central region			Rocky Mountain region			Western region
Districts within region		A,B,C			D	E,F,G			H,I,J,K			L,M,N,O,P
Additional districts		E,F,G			–	C						
Number of fuels		2				6			3			–
Test	ASTM	Minimum	Average	Maximum	No Analyses	Minimum	Average	Maximum	Minimum	Average	Maximum	No Analyses
Gravity, °API	D287	16.8		18.0	–	12.5	16.1	18.0	3.8	13.3	25.0	–
Flash point, °F	D93	170		182	–	166	–	200	150	–	200	–
Viscosity												
at 100° F, cs	D445	39		51.1	–	29.6	40.6	51.1	21.0	48.5	76.0	–
at 122° F, Furol sec	D88	–		–	–	–	–	–	–	–	–	–
Pour point, °F	D97	-10		50	–	-15	–	85	30	–	70	–
Sulfur content, wt%	D129	0.83		1.01	–	0.83	1.24	1.9	0.56	1.29	1.9	–
Carbon residue on 10%, wt%	D524	–		–	–	3.89	6.55	9.2	–	–	–	–
Ash, wt%	D482	0.01		0.011	–	0.0	0.01	0.02	–	–	–	–
Water and sediment, vol%	D1796	0.05		0.20	–	0.0	0.03	0.20	–	–	–	–
Gross Heat of Combustion, Btu/gal		149,219		149,993	–	149,219	150,481	152,785	144,764	152,296	158,490	–

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 28

Summary of Grade 5 (heavy) fuels

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region		Southern region	Central region		Rocky Mountain region			Western region		
Districts within region		A,B,C		D	E,F,G		H,I,J,K			L,M,N,O,P		
Additional districts		E			C		E,G					
Number of fuels		2		1	2		3			4		
Test	ASTM	Minimum	Maximum	(1 fuel)	Minimum	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	16.4	18.4	18.3	16.4	23.1	17.7	21.1	23.1	11.1	14.7	18.4
Flash point, °F	D93	170	200	180	170	176	145	-	200	192	-	206
Viscosity												
at 100° F, cs	D445	91.7	113.04	500	91.7		133	144.3	155.6	79	117	140
at 122° F, Furol sec	D88	-	-	-	31			31			31.3	
Pour point, °F	D97	-	-	-20	0		0		90	-10	-	10
Sulfur content, wt%	D129	0.90	0.95	1.78	0.7	0.90	0.7	1.27	2.23	1.00	1.47	1.7
Carbon residue on 100%, wt%	D524	4.6		-	-	-		5.51		6.41	6.94	7.41
Ash, wt%	D482	0.018		0.0285	-	-		0.03		0.02	0.026	0.04
Water and sediment, vol%	D1796	0.05	0.1	0.05	0.1			0.05		0.1	0.15	0.3
Gross Heat of Combustion, Btu/gal		148,962	150,251	149,026	145,962	150,251	145,962	147,218	149,412	148,962	151,343	153,699

From Shelton, E. M., "Heating Oils, 1979," Report No. BETC/PPS-79/4, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 29

Summary of Grade 6 fuels

Heating oil survey, 1979

Geographic distribution of heating oils		Eastern region			Southern region			Central region			Rocky Mountain region			Western region		
Districts within region		A,B,C			D			E,F,G			H,I,J,K			L,M,N,O,P		
Additional districts		D,E,F,G			A,B,C,G			B,C,D,H,J,O			E,F,G,O			G,J		
Number of fuels		29			23			21			9			21		
Test	ASTM	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum
Gravity, °API	D287	9.8	15.0	24.5	8.4	13.6	22.8	5.7	13.2	19.7	1.6	11.3	19.6	-4.5	13.3	23.5
Flash point, °F	D93	170	-	330	176	-	246	152	-	250	160	-	350	168	-	240
Viscosity at 122° F, Furol sec	D88	26.3	177.0	360	21.3	202.2	488.2	23.6	194.6	360	72	149.7	292	30	152.9	306
Pour point, °F	D97	5	-	95	10	-	90	15	-	65	15	-	90	15	-	85
Sulfur content, wt%	D129	0.23	1.30	3.0	0.32	1.65	3.0	0.49	1.53	2.9	0.9	1.59	2.9	0.19	1.27	3.1
Carbon residue on 100%, wt%	D524	0.34	6.86	11.11	3.7	6.68	10.9	0.88	8.48	16	6.19	12.2	17.2	3.8	8.07	11
Ash, wt%	D482	0.00	0.036	0.19	0.002	0.024	0.07	0.00	0.029	0.077	0.0	0.031	0.06	0.001	0.034	0.09
Water by distillation, vol%	D95	0.0	0.05	0.2	0.0	0.08	0.4	0.00	0.08	0.2	0.00	0.05	0.1	0.0	0.06	0.1
Sediment by extraction, wt%	D473	0.001	0.07	0.25	0.0	0.04	0.1	0.01	0.08	0.3	0.01	0.02	0.07	0.01	0.05	0.18
Gross Heat of Combustion, Btu/gal		145,079	151,160	154,550	146,152	152.055	155,468	148,127	152,325	157,241	148,191	153,552	159,935	145,710	152,151	163,922

"From Shelton, E. M., "Heating Oils [illegible] Report No. BETC/PPS-79/4, produced under a cooperative agreement between the D[illegible]ent of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesvi[illegible], Oklahoma, and the American Petroleum Institute (API)."

TABLE 30

Summary of Type S-M fuels

Diesel fuel survey, 1979

Geographic distribution of diesel fuels		Eastern region	Southern region			Central region			Rocky Mountain region	Western region		
Districts within region		A,B,C	D			E,F,G			H,I,J,K	L,M,N,O,P		
Additional districts		E,F,G				C						
Number of fuels		1	4			3			-	3		
Test	ASTM	(1 fuel)	Minimum	Average	Maximum	Minimum	Average	Maximum	(No Analyses)	Minimum	Average	Maximum
Gravity, °API	D287	-	23.8	29.6	39.1	33.0	34.9	37.8	-	33.4	38.3	47.1
Flash point, °F	D93	-	152	-	254	146	-	158	-	120	-	212
Color, ASTM	D1500	-	L0.5	-	1.0	1.5	-	L2.0	-	0.5	-	L0.5
Viscosity at 100° F:												
Kinematic, cs	D445	-	2.40	7.02	20.1	2.37	2.59	2.70	-	1.43	3.01	4.0
Saybolt Universal, sec.	D88	-	34.0	48.9	98.2	33.9	34.6	35.0	-	-	36.0	39.2
Cloud point, °F	D2500	-	6	-	10	-2	-	2	-	-6	-	46
Pour point, °F	D97	-	-10	-	65	-15	-	0	-	-10	-	10
Sulfur content, wt%	D129	-	0.13	0.72	2.45	0.26	0.28	0.30	-	0.02	0.10	0.17
Aniline point, °F	D611	-	103	116	129	133.0	144.0	155.0	-	-	-	-
Carbon residue:	D524											
on 10%, wt%		-	0.014	0.050	0.068	-	-	0.13	-	0.03	0.06	0.10
on 100%, wt%		-	-	-	0.39	-	-	-	-	-	-	-
Ash, wt%	D482	-	0.000	0.001	0.002	0.000	0.0007	0.001	-	0.0000	0.0003	0.001
Cetane number	D613	-	32.3	35.4	40.4	-	-	-	-	-	-	49
Cetane index	D975	-	-	-	54.4	43.2	46.6	53.2	-	53.1	54.6	56.5
Distillation temp, °F												
volume recovered:	D86											
IBP		-	370	395	418	358	366	370	-	-	-	390
10%		-	416	446	478	419	471	424	-	359	435	478
50%		-	494	510	530	490	498	503	-	412	498	550
90%		-	575	594	604	580	585	590	-	486	580	635
End point		-	635	649	662	618	635	645	-	521	621	690

From Shelton, E. M., "Diesel Fuel Oils, 1979," Report No. BETC/PPS-79/5, produced under a cooperative agreement between the Department of Energy (DOE), Bartlesville Energy Technology Center (BETC), Bartlesville, Oklahoma, and the American Petroleum Institute (API).

TABLE 31

TYPICAL NUMBER 5 AND 6 FUEL OILS IN THE UNITED STATES

	Midwest	East Coast		Gulf Coast		West Coast	Caribbean	African
	No. 6	No. 5	No. 6	No. 6	No. 6-1% S	No. 6	No. 6	No. 6
Gravity: °API	3.6	9.1	15.1	13.7	16.4	12.4	14.7	21.3
Density: Lb./U.S. Gal. at 60°F.	8.723	8.382	8.038	8.116	7.967	8.189	8.060	7.712
Viscosity, SUV: Sec.								
100°F.	186.3	200	2505	4794	8606	5558	4517	1570
130	86.2	97.1	818	1462	1406	1462	1261	-
210	40.5	43.5	122.0	193.3	166.5	175.2	161.0	-
Viscosity, Furol: Sec.								
122°F.	-	-	109.4	198.7	200	200	169.9	72.9
Flash, P-M: °F.	225	205	220	210	190	154	220	240
Flash, OC: °F.	335	295	300	320	320	290	305	-
Fire, OC: °F.	400	335	360	395	345	335	340	-
Pour Point: °F.								
Maximum	+40	+10	+45	+25	+65	+45	+20	+55
Minimum	+35	+5	+40	+20	+40	+35	+15	-
Sulfur: % by Wt.	1.46	0.81	0.78	2.05	0.85	1.73	2.18	0.48
Water by Dist'n., ASTM D95	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	0.1	-
Water and Sediment: % by Vol.	< 0.05	< 0.05	< 0.05	0.10	0.10	0.10	0.05	0.10
Sediment, ASTM D473: % by Wt.	0.04	0.02	0.02	0.01	0.02	0.01	0.01	0.02
Carbon Residue, Con.: % by Wt.	3.29	4.24	8.05	11.4	7.50	11.2	10.9	7.2
Carbon-Hydrogen Ratio	11.0	9.6	7.8	8.0	7.6	8.1	7.6	-
Nitrogen: % by Wt.	-	-	0.33	-	-	0.92	0.44	0.31
Ash, ASTM D482: % by Wt.	0.04	0.01	0.02	0.03	0.01	0.03	0.05	0.01
Fusion Point, 1000°F., Ash: °F.	> 1500	> 1500	> 1500	> 1500	> 1500	> 1500	1196	-
Spectrographic Analysis: PPM								
Aluminum	80	15	15	5	6	2	8	7
Barium	-	0.6	-	8	1	0.4	-	-
Boron	-	-	-	-	0.02	-	-	-
Calcium	2	2	10	40	4	0.6	6	10
Chromium	0.06	0.2	0.5	0.8	0.09	0.2	0.2	0.4
Cobalt	-	1	3	1	2	3	-	-
Copper	0.06	0.03	0.07	0.1	0.04	0.07	0.01	0.1
Iron	10	4	7	20	10	40	3	3
Lead	-	0.5	-	50	1	-	-	2
Magnesium	4	2	10	15	1	0.2	2	80
Manganese	0.5	0.3	0.7	0.5	0.2	0.5	-	0.5
Molybdenum	-	-	0.2	0.3	-	0.2	0.7	0.6
Nickel	1.3	5.7	25	18	9.3	102	58	42
Potassium	0.7	0.3	0.4	0.4	0.03	0.2	0.3	3
Silicon	100	10	10	5	6	3	2	3
Silver	-	-	0.01	-	-	0.01	0.04	0.01
Sodium	7	4	6	6	8	0.9	15	50
Strontium	0.5	0.2	0.6	0.7	0.4	0.2	0.9	0.9
Tin	-	0.6	4	-	-	-	-	5
Titanium	3	0.4	0.8	0.3	0.2	0.7	2	0.5
Vanadium, GRM 803	1.0	2.4	20	20	5.2	60	179	16
Zinc	-	-	-	10	-	-	-	-
Heat of Combustion, Calculated								
BTU/Lb. Gross	17,944	18,358	18,858	18,400	18,713	18,243	18,406	19,006
BTU/Gal. Gross	156,526	153,877	151,580	149,334	149,016	149,392	148,352	146,571

TABLE 32
TRACE METALS IN CRUDE OILS*

(Samples showing approximate highest and lowest values)

Source	No. of Samples	API Gravity	ppm of metals		
			V	Ni	Others
Middle East	45				
Abu Dhabi		37.1-38.9	nil-1.5	0.43	-
Belayim, Egypt		26.7	120	71.9	58 Fe
Venezuela	95				
San Joaquin		45.5-45.9	0.3-0.6	0.1-0.4	1.1 Ne
Boscan		9.8-10.6	1100-1150 1200-1400	100-150	6-60 Fe
California	34				
Wheeler Ridge		35.0	7	1.9	2 Na
Nicolai		-	246.5	-	-
Texas and Louisiana	36				
Conroe, Texas		37.6	0.008	Trace	2.18 Na
Heidelberg Eucutta, Miss.		22.5	15.35	6.02	38.6 Na
U.S., Other	31				
Lost Soldier, Wyoming		34.0	0.56	0.72	-
Tatums, Oklahoma		22.0	110.0	53.0	
World, Other	37				
Bulgarian		19.2	0.04	0.4	66 Fe
Zarzaitine, Libya		40.7-41.8	0.2-1.5	-	4.8 Na
Rhodener, Germany		32	176	29.1	35.8 Fe
Total	278				

*Abstracted from Nelson, W. L., "How much metals in crude oil?" The Oil and Gas Journal, Aug. 7, 1972, p.48-49. The 900°+F residue might contain 1.5 to 10 times the concentrations shown for crude oils; the lighter crudes showing the greatest increases in concentration because of the higher percentage of distillate boiled off.

Table 33 Typical Properties of Residual Fuels
Before and After HDS Processing**

	Kuwait 650°F+				Alaskan North Slope			
Charge Stock *					Put River 680°F+		Sag River 680°F+	
HDS Type	Untreated	II	III	IV	Untreated	II	Untreated	III
Product Yield: Vol %	-	89.4	97.5	97.1	-	97.7	-	96.8
Product Properties								
Cut Point: °F+	650	650	375	375	680	650	680	650
Gravity: °API	16.6	20.0	23.4	24.1	15.9	20.9	16.1	22.0
Sulfur: Wt %	3.8	1.0	0.3	0.1	1.59	0.30	1.45	0.10
Carbon Res: Wt %	9.0	5.81	3.33	2.75	7.36	3.74	3.20	1.17
Nitrogen: Wt %	0.22	0.18	0.13	0.09	0.10	0.08	0.10	0.07
Nickel: ppm	15.0	4.6	1.3	0.4	11.6	4.3	7.0	1.3
Vanadium: ppm	45.0	8.2	2.2	1.0	27.4	4.9	34.5	1.3
Viscosity: SUV (210°F)	250	107.3	52	45	137.9	79.8	161	53.1
Ash: Wt %	0.02	0.004	0.003	0.003				
Salt:* ppm	44.9[1]	0	0	0				
Heat of Comb: Btu/Lb		19,110	19,250	19,375				
Hydrogen: Wt %		12.1	12.5	12.7				
Carbon: Wt %		86.7	87.1	87.1				
Pour Point: °F		+60	+35	0				
Chem H_2 Cons: SCF/B	-	497	663	812	-	260	-	334

[1] Typical, before desalting

Conversion Factors: °C = (°F-32)/1.8, kJ/kg = btu/lb x 2.326, m^3/m^3 = SCF/Bbl x 0.178

*Salt refers to all water-soluble cations, determined as halide and reported as NaCl

**From Amero, R. C., Silver, R. S., and Yanik, S. J., "Hydrodesulfurized Residual Oil as Gas Turbine Fuels", ASME Paper 75-WA/GT-8 from ASME Winter Annual Meeting, Houston, Texas, Nov. 30-Dec. 4, 1975

TABLES AND FIGURES

FOR

1.2 COAL LIQUIDS AND SHALE OIL

Table A1

PROPERTIES OF SRC-II FUEL OIL FRACTIONS

	Middle Distillate	Heavy Distillate
Composition:		
Hydrogen, Wt. %	8.9-9.3	7.2-7.7
Sulfur Total, Wt. %	0.2	.37-.47
Nitrogen Total, Wt. %	0.8-1.1	1.2-1.4
Hydrocarbon Compositional Anal.		
Ash, Wt. %	<.001	.03-0.1
Ash Melt Temperature, °F	NA	NA
Aromatics Type:		
Aromatics Total, Vol. %	65-65	NA
Saturates	35-40	NA
Olefins	NA	NA
Naphthalenes	14-19	NA
Carbon Residue:		
On 10% Wt. %	<1.2	-
On 100% Wt. %	-	<1.2
Water & Sediment, Vol %	NA	NA
Volatility:		
Distillation Temperature, Volume Recovered, °F --- max.		
Initial Boiling Point	338-396	538-554
10%	386-406	568-584
50%	425-444	640-656
Final Boiling Point	483-500	928-939
Residue	1.0	-
Flash Point, °F	>160	>180
Gravity, °API	13.6-14.0	0.4-1.0
Fluidity:		
Pour Point, °F	<-45	+15-+45
Viscosity at 100°F:		
Kinematic, cS	3.1-3.4	49.6-90.2
Saybolt Universal, Sec.	36.3-37.3	342-418
Combustion:		
Net Heat of Combustion, Btu/lb	16,900	17,000
Thermal Stability:		
JFTOT, Breakpoint Temperature, °F (TDR,13; P, 25 mm)	NA	NA

Table B1

H-COAL YIELD STRUCTURES: EFFETS OF PROCESS CONDITIONS AND COAL TYPE

Column No.:	A	B	C	D	E
Reference:	1	1	2	5	5
Process Severity (a):	Lo	Hi		Hi	Hi
Coal Type:	Ill.	Ill.		Ill.	Wyodak
Normalized Product Distribution					
C_1-C_3 Hydrocarbons	10.7	5.4	9.4	6.5	9.5
C_4-400°F Distillate	17.2	12.1	25.2	29.0	48.5
400-650°F Middle Distillate	28.2	19.3	12.9	42.7	39.1
650-975°F Heavy Distillate	18.6	17.3	13.3	21.8	2.9
975°F+ Residual Oil	10.0	29.5	22.9	(100)	(100)
Unreacted Ash-Free Oil	5.2	6.8	6.8		
H_2O, NH_3, H_2S, CO, CO_2	15.0	12.8	14.3		
Total (100.0 + H_2 Reacted)	104.9	103.2	104.7		
Hydrogen Consumption, SCF/Ton	18,600	12,200			

(a) "Hi" refers to Syncrude processing conditions; "Lo" refers to fuel oil maximizing processing conditions.

Table B2

PROPERTIES OF H-COAL PRODUCTS

Sample No.[a]:	A	B	C	D	E	F	G	H	I
Reference:	3	3	4	4	4	5	5	5	5
Process Severity[b]:	Raw	Upgraded	NA	NA	NA	Hi	Hi	Hi	Hi
Coal Type:	Bituminous					Illinois	Illinois	Wyodak	Wyodak
Process Stream[c]:	Various Fractions of MD and HD					MD	HD	MD	HD
Composition:									
Hydrogen, Wt. %	10.3	10.7	11.19	11.38	10.03	9.7	7.6	10.5	8.1
Sulfur Total, Wt.%	0.03	<0.01	0.16	0.13	0.09	0.18	0.22	<0.07	0.13
Nitrogen Total, Wt.%	0.40	0.30	0.16	0.16	0.33	0.42	1.01	0.22	0.70
Hydrocarbon Compositional Anal.	NA	NA							
Ash, Wt. %			<.01	<.01	<.01				
Ash Melt Temperature, °F									
Aromatics Type:									
Aromatics Total, Vol. %	65	40	29.0	34.0	43.0				
Saturates	---	---							
Olefins	---	---							
Naphthalenes	---	---							
Carbon Residue:									
On 10% Wt. %									
On 100% Wt. %			0.01	0.05	0.08				
Water & Sediment, Vol %	---	---							
Volatility:									
Distillation Temperature, Volume Recovered, °F --- max. (D86)									
Initial Boiling Point	400	500	220	236	352	400	650	400	650
10%									
50%									
Final Boiling Point	500	650	485	505	634	650	975	650	975
Residue									
Flash Point, °F	200	270	12.0	<75.0	145.0				
Gravity, °API			30.4	30.0	18.4	17.5	5.0	24.1	9.6

(a) Samples number A, B, - bear no relation to column headings A, B, in Table B1.

(b) "Hi" refers to syncrude processing conditions; "Lo" refers to fuel oil maximization

(c) "MD": middle distillate; "HD": heavy distillate

Table B2 (Continued)

PROPERTIES OF H-COAL PRODUCTS

Sample No.:	A	B	C	D	E	F	G	H	I
Reference:	3	3	4	4	4	5	5	5	5
Process Severity[b]:	Raw	Upgraded	NA	NA	NA	Hi	Hi	Hi	Hi
Coal Type:						Illinois	Illinois	Wyodak	Wyodak
Fluidity:									
Pour Point, °F	-90	-50				-100	86	-30	90
Viscosity at 100°F:									
Kinematic, cS			0.60	0.62	0.99				
Saybolt Universal, Sec.						41	(163)	35.1	(97)
Combustion:									
Net Heat of Combustion, Btu/lb									
Gross Heat of Combustion, Btu/lb	18,100	18,300	18,810	18,723	18,331				
Thermal Stability:									
JFTOT, Breakpoint Temperature, °F (TDR,13; P, 25 mm)	---	---							

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(b) "Hi" refers to syncrude processing conditions; "Lo" refers to fuel oil maximization

PROPERTIES OF EDS FRACTIONS FROM ILLINOIS NO. 6 COAL[a]

			Middle Distillate		Heavy Distillate		
	Naphtha C5-400°F		Solvent 400-700°F		Vacuum Gas Oil 700-100°F	Coker Liquids 1000°F+	Full Range[b] Fuel Oil Blend 400-1000°F
	Raw	P/H	Raw	P/H	Raw		Raw
Composition:							
Hydrogen, Wt. %	12.2	13.4	8.9	10.3	6.5	6.0	8.4
Sulfur Total, Wt.%	1.0	0.007	0.3	0.002	1.3	1.2	0.6
Nitrogen Total, Wt.%	0.2	0.01	0.3	0.03	1.4	1.5	0.7
Hydrocarbon Compositional Anal.							
Ash, Wt. %					0.1	1.4	0.027
Ash Melt Temperature, °F							
Aromatics Type:							
Aromatics Total, Vol. %							
Saturates							
Olefins							
Naphthalenes							
Carbon Residue:							
On 10% Wt. %							
On 100% Wt. %							3.61
Water & Sediment, Vol %							2.0
Volatility:							
Distillation Temperature, Volume Recovered, °F --- max. (D86)							
Initial Boiling Point							
10%							
50%							
Final Boiling Point							
Residue							
Flash Point, °F							
Gravity, °API							

(a) Ref. C2, p. 152 / (b) Ref. C2, p. 155-156

Table C1 (Continued)

PROPERTIES OF EDS FRACTIONS FROM ILLINOIS NO. 6 COAL[a]

	Naphtha C5-400°F Raw	Naphtha C5-400°F P/H	Middle Distillate Solvent 400-700°F Raw	Middle Distillate Solvent 400-700°F P/H	Heavy Distillate Vacuum Gas Oil 700-100°F Raw	Heavy Distillate Coker Liquids 1000°F+	Full Range[b] Fuel Oil Blend 400-1000°F Raw
Fluidity:							
Pour Point, °F	<-70	<-70	-5		190	270	20
Viscosity at 100°F: (210°F)							
Kinematic, cS	0.9		4.3	3.0	(100)	(>1000)	21
Saybolt Universal, Sec.							
Combustion:							
Net Heat of Combustion, Btu/lb							17,314
Thermal Stability:							
JFTOT, Breakpoint Temperature, °F (TDR,13; P, 25 mm)							
Specific Gravity 60/60°F	0.82	0.79	0.96	0.95	1.2	1.5	1.040

(a) Ref. C2, p. 152 / (b) Ref. C2, p. 155-156

Table C2

PROPERTIES OF EDS FRACTIONS FROM WYODAK[a] COAL[b]

	Naphtha IBP-350°F		Middle Distillate	Heavy Distillate	
			Solvent 350-650°F	Vacuum Gas Oil 650-1000°F	Full Range Fuel Oil Blend[c] 350-1000°F
	Raw	P/H	Raw	Raw	Raw
Composition:					
Hydrogen, Wt. %	11.95	12.17	10.22	7.13	8.13
Sulfur Total, Wt.%	0.11	0.006	0.03	0.13	0.10
Nitrogen Total, Wt.%	0.11	0.07	0.27	0.98	0.48
Hydrocarbon Compositional Anal.					
Ash, Wt. %				0.03	
Ash Melt Temperature, °F					
Aromatics Type:					
Aromatics Total, Vol. % (FIA)	23.7	36.8	64.2		
Saturates					
Olefins					
Naphthalenes					
Carbon Residue:					
On 10% Wt. %q	0	0	0.06	17.2	2.85
On 100% Wt. %					
Water & Sediment, Vol %		.05	0.10	0.05	0.08
Volatility:					
Distillation Temperature, Volume Recovered, °F --- max. (D86)					
Initial Boiling Point					
10%					
50%					
Final Boiling Point					
Residue					
Flash Point, °F		73	152	435	158
Gravity, °API	40.95	41.5	20.6	1.15	5.7

(a) Wyoming; subbituminous / (b) Ref. 3, p. 413

(c) 10.9% 350-400°F, naphtha, 25.5% excess solvent, 63.6% vacuum gas oil (Ref. p. 103)

Table C2 (Continued)

PROPERTIES OF EDS FRACTIONS FROM WYODAK[a] Coal[b]

	Naphtha IBP-350°F		Middle Distillate	Heavy Distillate	
			Solvent 350-650°F	Vacuum Gas Oil 650-1000°F	Full Range Fuel Oil Blend[c] 350-1000°F
	Raw	P/H	Raw	Raw	Raw
Fluidity:					
Pour Point, °F		-35	-35	115	+45
Viscosity at 100°F:					
Kinematic, cS		0.43	0.82	385	2.3
Saybolt Universal, Sec.					
Combustion:					
Net Heat of Combustion, Btu/lb					
Thermal Stability:					
JFTOT, Breakpoint Temperature, °F (TDR,13; P, 25 mm)					

(a) Wyoming; subbituminous

(b) Ref. 3, p. 413

(c) 10.9% 350-400°F naphtha, 25.5% excess solvent, 63.6% vacuum gas oil (Ref. p. 103)

Table C3

EDS SAMPLES USED IN GAS TURBINE COMBUSTION TESTS[a]

	(A) EDS Sample Submitted for Gas Turbine Combustor Test	(B) 350-650°F Fraction From (A)
Composition:		
Hydrogen, Wt. %	9.95	10.16
Sulfur Total, Wt.%	0.031	0.02
Nitrogen Total, Wt.%	0.081	0.044
Hydrocarbon Compositional Anal.		
Ash, Wt. %	0.001	0.001
Ash Melt Temperature, °F		
Aromatics Type:		
Aromatics Total, Vol. %	48.4[b]	46.8
Saturates		
Olefins		
Naphthalenes		
Carbon Residue:		
On 10% Wt. %	.03	.03 (10% btms)
On 100% Wt. %		
Water & Sediment, Vol %		
Volatility:		
Distillation Temperature, Volume Recovered, °F --- max. (D86)		
Initial Boiling Point	312 (5%)	409 (5%)
10%		
50%		
Final Boiling Point	695 (95%)	602 (95%)
Residue		
Flash Point, °F	100	122
Gravity, °API	16.0	17.1

(a) Ref. C3, p. 416

(b) % aromatic ring; by NMR

Table C3 (Continued)

EDS SAMPLES USED IN GAS TURBINE COMBUSTION TESTS[a]

	(A) EDS Sample Submitted for Gas Turbine Combustor Test	(B) 350-650°F Fraction From (A)
Fluidity:		
Pour Point, °F	<-36	<-36
Viscosity at 100°F:		
Kinematic, cS	2.7	2.34
Saybolt Universal, Sec.		
Combustion:		
Net Heat of Combustion, Btu/lb		
Gross Heat of Combustion, Btu/lb	18,340	18,400
Thermal Stability:		
JFTOT, Breakpoint Temperature, °F (TDR,13; P, 25 mm)		

(a) Ref. C3, p. 416

FIGURE A1. THE SRC-II PROCESS

LIQUEFACTION REACTOR SECTION

Coal-solvent mixing reaction
with H_2 in reactor

SEPARATIONS AND HYDROGEN GENERATION SECTION

Flash separation of gases

Distillation of liquid product fractions

Separation of solids

H_2 Production by gasification of bottoms slurry

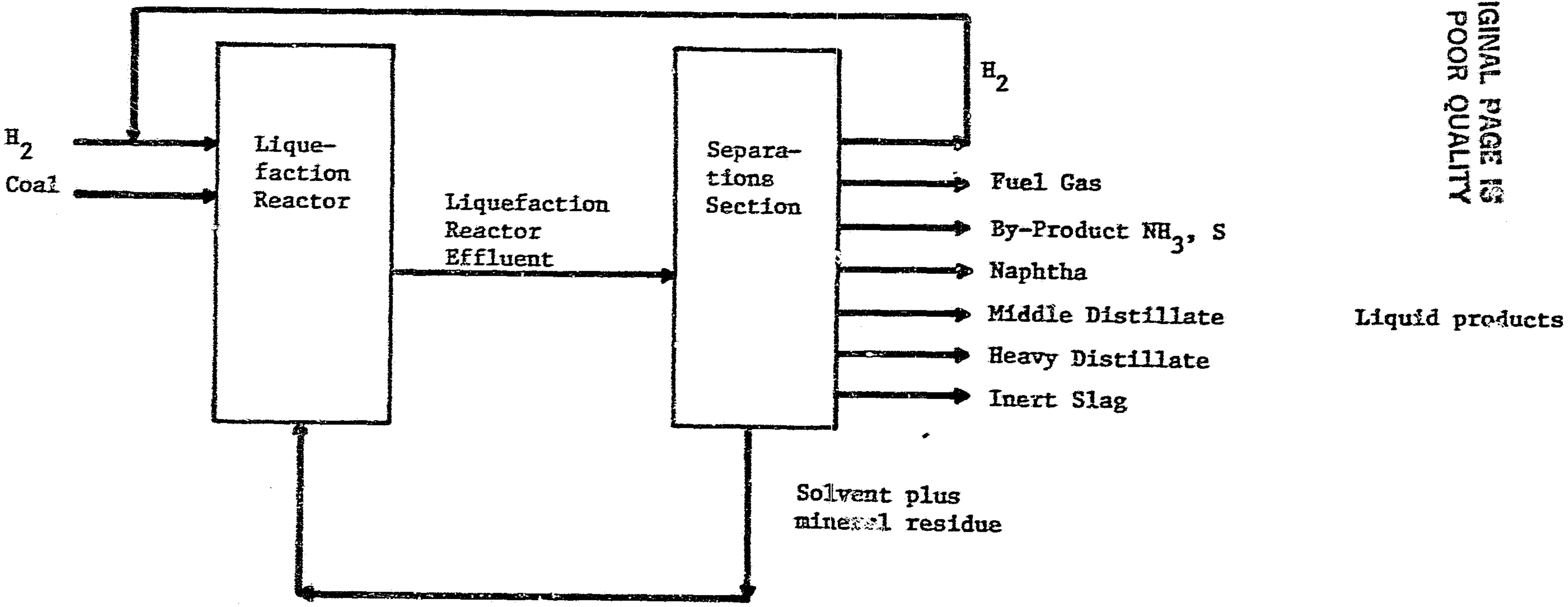


FIGURE B1. THE H-COAL PROCESS

LIQUEFACTION REACTOR SECTION

Coal-solvent mixing reaction with H_2 in reactor

SEPARATIONS AND HYDROGEN GENERATION SECTION

Flash separation of gases

Distillation of liquid product fractions

Separation of solids

H_2 production (method unspecified)

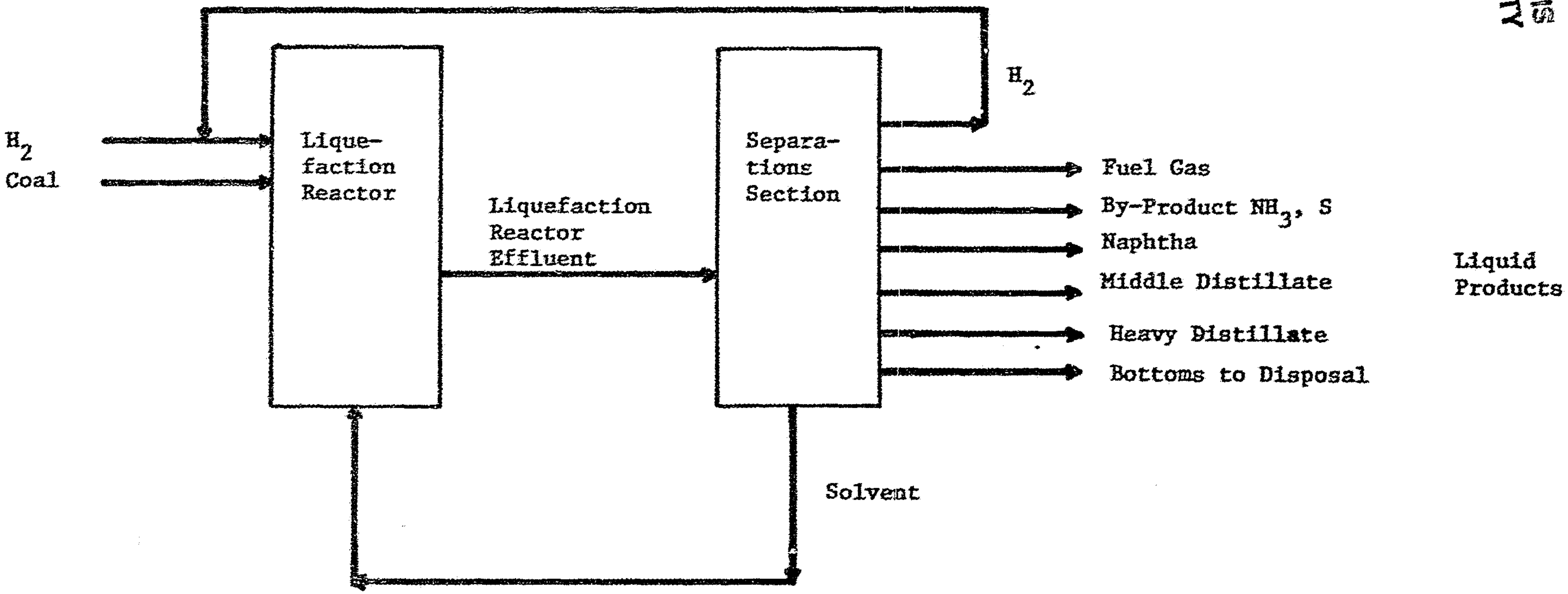


FIGURE C1. THE EXXON DONOR SOLVENT PROCESS (EDS)

LIQUEFACTION REACTOR SECTION

Coal-solvent mixing reaction with H_2 in reactor

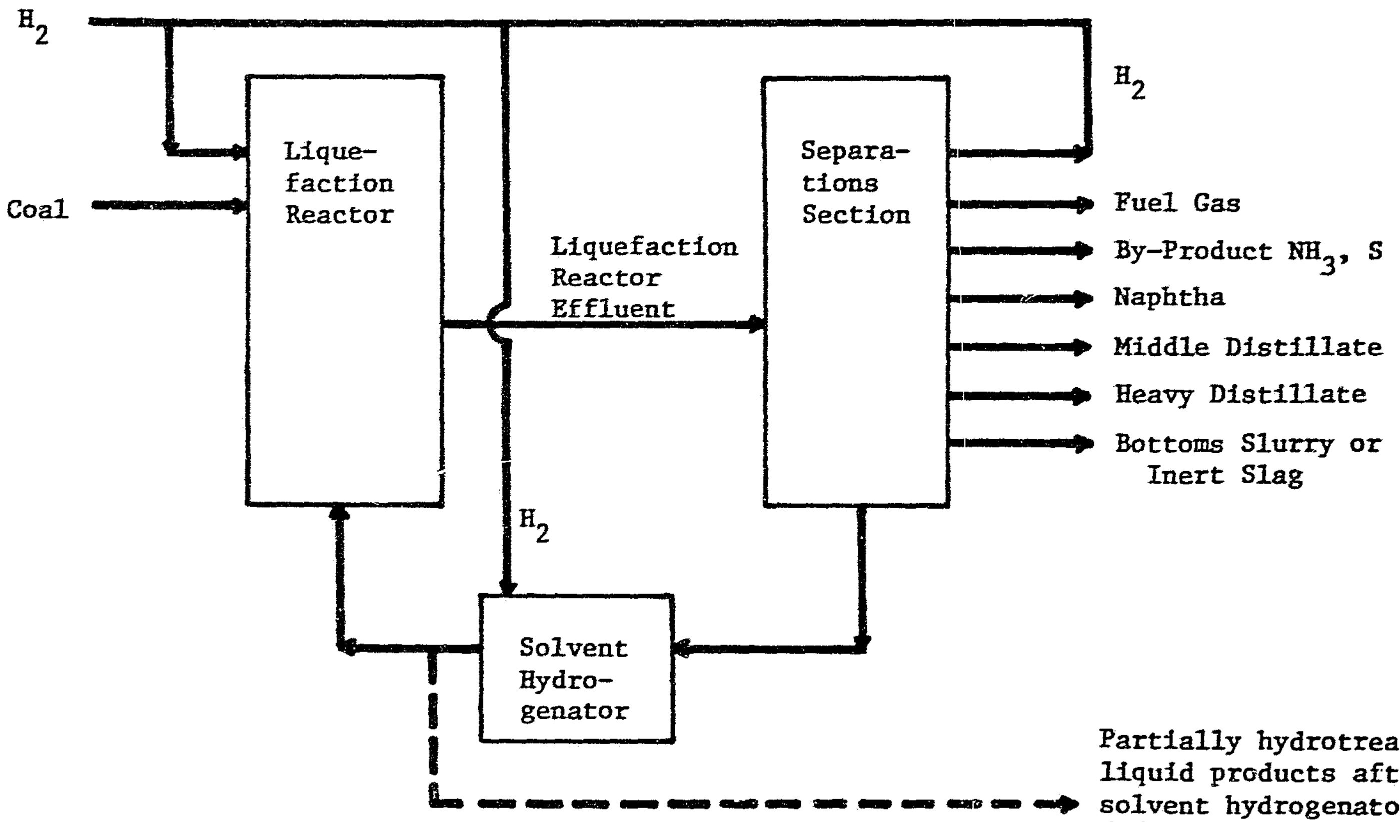
SEPARATIONS AND HYDROGEN GENERATION SECTION

Flash separation of gases

Distillation of liquid product fractions

Separation of solids

H_2 production*



"raw" liquid products before solvent hydrogenator ("MPSS")

Partially hydrotreated liquid products after solvent hydrogenator ("P/H" in Table C1 and C2; "Hydrotreated MPSS" in Table C3)

*See text for description of options

FIGURE C2. OPTIONS FOR EDS BOTTOMS SLURRY DISPOSITION

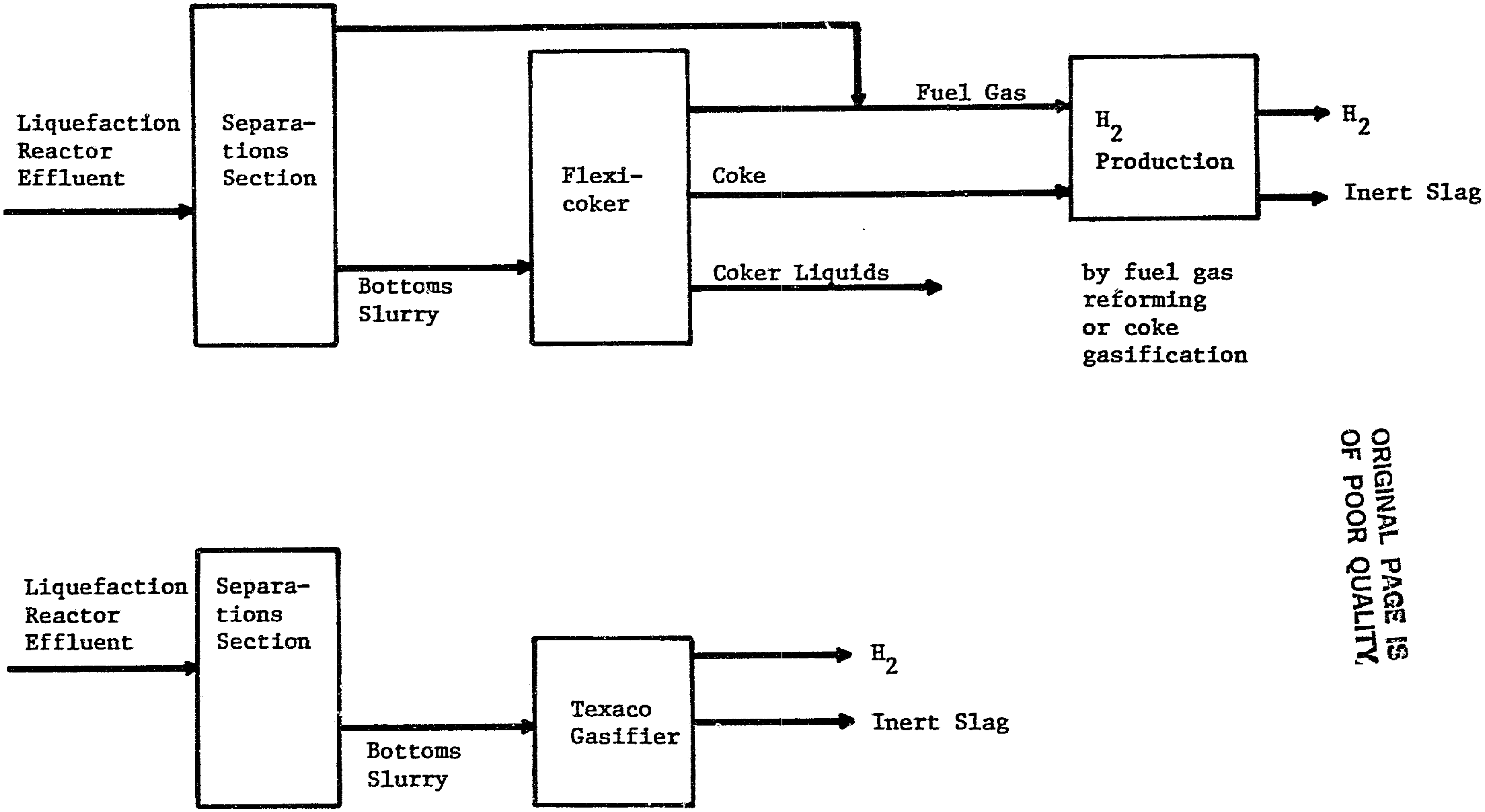


Figure C2A

Figure C2B

TABLES AND FIGURES

FOR

1.5b SO_x EXHAUST GAS CLEANUP

Table I

CURRENT GAS SO_x REMOVAL REQUIREMENTS

Basis: Fuel Oil Cleaned to 0.5% S

	Emission Standard Equivalent %S in Fuel	% SO_2 To be Removed from Exhaust Gas
EPA, September 10, 1980	0.8	0
California State	0.5	0
New York State	0.3	40
New York City	0.2	60
Other States	f0.5	0

Table II

CHARACTERISTICS OF COMMERCIAL FGD PROCESSES(3)

Process	Primary Removal Agent	Regenerable/ Throwaway	Principal Sulfur Product	Operational Mode
Lime/Limestone	Lime or Limestone	Throwaway	$CaSO_3$	Wet
Alkaline Fly Ash	Alkaline Fly Ash	Throwaway	$CaSO_4$	Wet
Sodium Carbonate	Sodium Carbonate	Throwaway	Na_2SO_3	Wet
Double Alkali	Sodium Hydroxide	Regenerable	$CaSO_4$	Wet
Dilute Sulfuric Acid/Gypsum	Sulfuric Acid	Regenerable	$CaSO_4$	Wet
Magnesium Oxide	Magnesium Oxide	Regenerable	SO_2	Wet
Wellman-Lord	Sodium Sulfite	Regenerable	SO_2	Wet
Spray Drying(4)	Lime or Sodium Carbonate	Throwaway	$CaSO_3/CaSO_4$	Dry

Table III

CHARACTERISTICS OF ADVANCED FGD PROCESSES(3)

Process	Sulfur Oxide Primary Removal Agent	Regenerable	Form of Primary Sulfur Product	Operational Mode
Agglomerating Cone	Phosphate Rock Slurry	No	Fertilizer	Wet
Allied/Wellman-Lord	Sodium Sulfite	Yes	Sulfur	Dry
Ammonia Scrubbing	Ammonium Solution	Yes	Sulfur	Wet
Basic Aluminum Sulfate - Gypsum	Aluminum Sulfate	Yes	Gypsum	Wet
Catalytic Oxidation	Vanadium Pentoxide	Yes	H_2SO_4	Dry
Citrate	Citric Acid	Yes	Sulfur	Wet
Copper Oxide (Shell)	Copper Oxide	Yes	SO_2	Dry
Dry Adsorption	Activated Carbon	Yes	Sulfur	Dry
Electrolytic Regeneration (Stone & Webster/Ionics)	Caustic Soda	Yes	H_2SO_4	Wet
Manganese Oxide	Manganese Oxide	Yes	SO_2	Dry
Aqueous Carbonate	Liquid Carbonate	Yes	H_2S	Wet
Nahcolite Injection	Nahcolite Ore	No	Na_2SO_4	Dry
Organic Absorbent	Glyoxylic Acid	Yes	SO_2	Wet
Potassium Thiosulfate	Sulfates, Sulfites	Yes	Sulfur	Wet
Phosphate	Phosphate Buffer	Yes	Sulfur	Wet

Table IV

PROJECTED COMMERCIAL AVAILABILITY OF ADVANCED PROCESSES(3)

Time Frame	Process
Current	Allied/Wellman-Lord Dry Scrubbing
1980-82	Ammonia Scrubbing Basic Aluminum Sulfate - Gypsum Dry Adsorption
1982-1983	Agglomerating Cone Catalytic Oxidation Citrate Copper Oxide (Shell) Aqueous Carbonate Nahcolite Injection Phosphate (Aquaclaus)
1983-1984	Electrolytic Regeneration (Stone & Webster/Ionics) Potassium Thiosulfate (Consol)
1986-1988	Gas Turbine Exhaust Scrubber(2) (Rolls Royce) Manganese Oxide