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COMPUTER MODEL FOR REFINERY OPERATIONS WITH EMPHASIS ON JET FUEL PRODUCTION
VOLUME I PROGRAM DESCRIPTION

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16. Abstract

The Fortran computing program will predict the flow streams and material, energy, and economic balances of a typical petroleum refinery, with particular emphasis on production of aviation turbine fuel of varying end point and hydrogen content specifications. The program has provision for shale oil and coal oil in addition to petroleum crudes. A case study feature permits dependent cases to be run for parametric or optimization studies by input of only the variables which are changed from the base case. The report has sufficient detail for the information of most readers. However, two subsequent volumes contain the mathematics and data base details and the program listing.

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COMPUTER MODEL FOR REFINERY OPERATIONS WITH EMPHASIS ON JET FUEL PRODUCTION. VOLUME I PROGRAM DESCRIPTION

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SUMMARY

This report contains a description of the Gordian Refinery Simulation Model. This is a Fortran computing program for predicting the flow streams and material, energy, and economic balances of a typical petroleum refinery, with particular emphasis on production of aviation turbine fuel of varying end point and hydrogen content specifications. The program has provision for shale and coal oil in addition to petroluem crudes; 26 crude assays are supplied, and the user may add up to 9 more or update the existing assays. The program contains relationships for predicting and blending the jet fuel freezing point and smoke point as well as internal stream and product hydrogen, nitrogen, and sulfur contents and other properties. A case study feature permits dependent cases to be run for parametric or optimization studies by input of only those variables which are changed from the base case.

This report is the first of three volumes. It is independent and has sufficient detail for the needs of most readers in interpreting the program features and output data. Two subsequent volumes contain the mathematics and data base details and the program listing.

COMPUTER MODEL FOR REFINERY OPERATIONS WITH EMPHASIS ON JET FUEL PRODUCTION: VOLUME I. PROGRAM DESCRIPTION

1.0 INTRODUCTION

Major price increases and the impending shortage of petroleum reserves with respect to increasing product demand has brought about a serious examination of possible changes in jet fuel composition. Specification aviation turbine fuel (ASTM D-1655) is produced from mid-distillate petroleum fractions, which compete with ever growing demands for diesel, fuel oil and petrochemical feedstocks. Increased distillate production from present crudes is feasible, but conversion of gas oils and residuals increases the aromatic content of the mid-distillate pool. Moreover, promising alternate crude sources, such as shale oil, tar sands, and coal liquids yield distillates also with increased aromatic, nitrogen and sulfur contents. Special processing would be required to produce present specification aviation turbine fuel from these sources.

This view of the future has stimulated a reexamination of the optimum combination of jet fuel specifications, with respect to the refinery processing, the supply distribution system, the aircraft fuel system, and the fuel combustion qualities. The goals of current studies are assessing the suitability of jet fuels produced from cracked petroleum and alternate crude sources and developing a data base which will allow optimization of future fuel characteristics. Future aviation turbine fuel specifications must represent a trade-off between energy and cost efficiency of manufacture and aircraft and engine design and performance.

This report deals with the refinery portion of the overall program. In order to have a systematic way of determining the energy efficiency of the production of various product slates involving different crude sources and different processing schemes, the Lewis Research Center of NASA has supported the development of this computer model for petroleum refinery operation. The primary objectives of this model are:

1. the flexibility to configure a refinery involving any or all of the process units commonly employed in the production of gasoline, jet fuels, and mid-distillates;

2. the ability to produce jet fuel blends of varying end-point specification and varying specified hydrogen content as part of the total slate of products;

3. the ability to handle synthetic crudes (shale and coal derived) with varying severities of hydroprocessing;

4. the determination of overall refinery energy efficiency;

5. the determination of sulfur, nitrogen, and hydrogen material balances for each process unit and for the overall refinery; and

6. the capability of carrying out economic calculations.

The Gordian Refinery Simulation Model, presented herein, has all the above capabilities. This report, Volume I of three volumes, contains the detailed information necessary to run the program, and a brief discussion of the technical basis of the model and its limitations in the present state. Volume II (NASA CR-135334) contains details of the mathematical relations and data bases used in the program, and Volume III (NASA CR-135335) contains programming documentation. The complete documentation and program tape are available through the Computing Software and Management Information Office (COSMIC) under the number LEW-13047.

2.0 PROGRAM DESCRIPTION AND LOGIC

2.1 General Description and Applications

The Gordian Refinery Simulation Model is a Fortran computer program which is capable of predicting the production volumes of petroleum refinery products, with particular emphasis on aircraft turbine fuel blends and their key properties. The program also provides the calculation of capital and operating costs for the refinery and its margin of profitability. This model is noteworthy in that it includes provision for the processing of synthetic crude oils from oil shales and coal liquefication processes. The program provides highly detailed blending computations for alternative jet fuel blends of varying end-point specification. Volumetric and weight balances are output along with complete sulfur, nitrogen and hydrogen balances. Energy usage is reported in terms of net fuel power and steam consumption along with the hydrogen usage. Results are reported in SI metric and English units.

In order to use the program, it is necessary to specify the type and volume of each crude oil which makes up the feed to the refinery as well as the capacities of the specific refinery processing units which comprise the refinery configuration. The complete slate of refinery products is then calculated by the program, with particular emphasis on accurately predicting the volumes and properties of the jet fuel, distillate and residual fuel oil blends produced. The economic calculations require the input of crude oil prices, refinery product realizations, electricity cost and investment carrying charge.

While the model simulates the operation of a refinery, it does not optimize it with respect to maximum dollar profit in the way that a linear programming model does. The non-linear relationships which have been programmed (e.g. for turbine fuel smoke point and freezing point prediction) allow for greater accuracy than may be obtained in calculating the product blends normally obtainable with the conventional linear programming approach. An additional advantage is that less training is required and less data input and program usage complexities are encountered in using a Fortran program as opposed to a complex linear programming system.

Optimization and parametric type studies in general, however, may be made by using the case study feature which has been incorporated into the model. This feature is used by establishing a base case and then by specifying only the changes to the base case which are applicable to the case study sequence, thus minimizing input requirements and permitting large case study sequences to be run without undue user or computer time.

Two major data base subroutines are contained within the program, a Crude Assay subroutine and a Refinery Process Yield subroutine. The Crude Assay subroutine is comprised of the yields and properties of distillation products from a wide range of crude oils. The Refinery Process Yield subroutine contains typical process unit yields, energy requirements and stream quality factors for a variety of refinery processing units. In addition, an economic data base is contained in the model which provides the fixed and variable components of operating costs and investment costs for individual refinery process units.

Five potential categories of fuels production are considered by the Refinery Model:

1. Kerosene/Aviation turbine fuel
2. Diesel fuel
3. Direct gas oil sale
4. Distillate Fuel
5. Residual Fuel
6. Gasoline

The volumes of kerosene, diesel fuel and gas oil to be produced (if any) are specified in the input. Any excess kerosene or diesel is routed to turbine or distillate fuel while the remaining gas oil is either processed or blended directly to residual fuel.

An aviation turbine fuel blending subroutine calculates product blends at end-points of 525°F and 650°F, and any specified intermediate end-point. In addition, the user has the option of specifying the required hydrogen content for a given end-point turbine fuel, and the model will calculate the maximum quantity of fuel that can be produced to meet specification. Other properties of the kerosene/turbine fuel pool that are calculated are gravity (°API), sulfur content, nitrogen content, viscosity, freeze point, smoke point, paraffins, naphthenes, aromatics and heat of combustion.

The distillate and residual fuel oils usually comprise the bulk of the fuel oil production. The model calculates the following for both the distillate fuel and residual fuel oil pools:

1. Total pool volumes
2. Weight percent sulfur
3. Weight percent nitrogen
4. Weight percent hydrogen

5. API gravity

6. Viscosity

If desired, sulfur contents may be specified for distillate and residual fuel oil blends. The model will then calculate the maximum fuel oil volumes available at the specified sulfur contents, along with the other fuel oil properties. In order to make particular sulfur specifications, it is usually necessary to reject blending components from the total fuel oil pools. The model calculates the volume, sulfur content, and the other fuel oil properties of the "rejected" portions of the distillate and residual fuel oil pools.

If desired, the production volume and sulfur content of one or two distillate fuel oil blends may be specified. The program will calculate the composition and properties of these blends and will blend the remaining excess distillate components into the residual fuel oil pool. One or two residual fuel oil blends of fixed volume and sulfur content may also be specified. The composition and properties of these residual fuel oil blends (which now contain excess middle distillate components) will be calculated along with the volume and properties of the remaining residual fuel oil pool.

Use of the above blend specification options affords considerable flexibility in assessing the production capabilities in a given refining situation for fuels ranging from aircraft turbine level to residual fuel oil.

2.2 Technical Basis for Model

A brief summary of the technical background of the computer model is presented in this section. This information is given in more detail in Volume II (NASA CR-135334).

The model has storage capability for up to 35 crude assays. At present, the program contains within a subroutine 26 assays, including three shale oils and one coal syncrude. The petroleum crude assays were obtained from Gordian Associates, Inc. in-house data and from assays published in the Oil and Gas Journal. The shale and coal syncrude assay data were obtained from references 1 and 2. In those cases where a crude oil property needed for the program was not available from the assay data, either a correlation was used to derive the property or an estimate was used. Such cases are noted in Volume II.

Process unit yield data for the petroleum-derived fractions were obtained from Gordian in-house data and from ref. 3, and for the syncrude fractions from references 1 and 2. The process unit yield data base includes the energy requirements for each unit in the form of steam, refinery gas, and electrical power.

Several physical and chemical property blending correlations that are used in this model are summarized as follows:

1. Hydrogen content, if not specified as input or through the assay, is calculated from API gravity and mean average boiling point by the method described in ref. 4 for petroleum fractions. The same method, but with adjustments to the predicted carbon-hydrogen ratio, was used for the shale oil and coal oil cuts.

2. Heats of combustion were calculated from API gravity, Watson characterization factor, and sulfur content by a correlating relation also obtained from ref. 4. Heat of combustion is blended by weight.

3. Smoke points were calculated from Watson characterization factor by equations derived from data in ref. 5. Smoke point is blended volumetrically by a reciprocal blending relation.

4. Freezing point data, if not available through assay data, were estimated from a correlation presented in ref. 5. Freezing points of product streams from the process units were based upon changes in freezing point from the feed streams in order to tie the product freezing points as much as possible to the original crude oil assays. Freezing point blending of the jet fuel and mid-distillate blends was based on the blending index method of ref. 6.

5. Sulfur and nitrogen content, viscosity, and PNA (paraffins, naphthenes and aromatics) are based on crude assay values and on inspection tests accompanying process unit yield data. Viscosities are blended as shown in Exhibit 6 of this volume; the other properties here are blended by volume.

6. The economic calculation for the specific refinery configuration under study includes investment costs for the individual process units, off-site investment costs, fixed and variable operating costs. Crude or other feedstream costs, utility costs, product prices and rate of return on investment must be input for the particular case.

Some cautions regarding the use of the Gordian Refinery Simulation Model in its present form must be noted. Process unit data and correlations involving petroleum-derived fuels have a broad base of years of experience in the petroleum industry, and the calculations involving the use of petroleum crudes can be expected to have good reliability. Processing data and correlations involving shale or coal-derived fuels, however, are extremely limited at the present time, and the results calculated using these syncrudes would be expected to be much less reliable.

Nevertheless, it was desired to have a refinery simulation model which would be capable of handling these syncrudes, with the intent of continually upgrading the data and correlation bases as such information becomes available.

2.3 Review of Model Output

In order to provide an illustration of the capabilities of the model this section provides a review of the complete computer printout for a sample case. A copy of an actual computer output is shown in Exhibit 1. The computer print-out reports appear in the order in which the calculation proceeds within the model. While all of the report writing capabilities of the program are shown, there are options to selectively suppress various reports in a manner to be specified by the user.

The first set of reports give individual process unit material balances with respect to weight flow rate, sulfur, nitrogen, and hydrogen. Each material balance process unit report is followed by an energy utilization report showing the consumption of fuel, steam, electricity and hydrogen and their percentage of the total fuel oil equivalent (FOE) input to the refinery. Please note that while the hydrogen unit balance appears in error, this results from the fact that water feed and carbon dioxide product has been excluded from the weight balance as normal refinery practice.

The second set of reports refer to the jet fuel blends which may be produced by the combination of the specified refinery crude oil feedstocks and refinery process unit configuration. These reports have been generated to provide the full extent of jet fuel blending information which is available from the model. These blend reports are:

exact matches (except where sulfur and nitrogen is truly lost through the combustion of catalytic coke) since the process unit data base values are expressed in the program as a percentage distribution of sulfur and nitrogen between process unit products. Hydrogen distribution on the other hand, is not handled in this manner, but is calculated from an API Technical Data Book correlation (ref. 4) which relates hydrogen content to specific gravity and the mean average boiling point of the stream, with adjustment factors applied for coal and shale oil fractions. The overall hydrogen of 100.9 weight percent appears good, but is deceptive. While the results for units which process petroleum fraction is generally good, rather significant discrepancies can be observed for the shale and coal oil processing units. The reason here is a combination of relatively weak process unit data available at the present time to relate yields to hydrogen consumption and downstream product qualities, and probable deficiencies in the correlation used to predict hydrogen content for the shale and coal oil species.

A summary of process unit operations is next shown which compares the input process unit capacity with the actual feedrate. Process unit severities are also given. Separate reports are printed which summarize the overall refinery energy efficiency and usage and the properties of the blended gasoline pool.

The final section of the computer printout report gives an overall economic summary of refinery operations. The profit margin calculations shown are illustrative only since actual crude oil prices, product realizations, and investment carrying charges depend on the specific refining situation. However, the process unit investment costs and operating costs are contained in the program as data base items. These

(a) Properties of the total 525°F endpoint pool

(b) Properties and quantity of 525°F endpoint pool at the specified hydrogen content. (12.8 weight percent in this run).

(c) Properties of the total 650°F endpoint pool

(d) Properties and quantity of 650°F endpoint pool at the specified hydrogen content.

(e) Properties of the total pool at the specified endpoint (600°F in this run)

(f) Properties and quantity of the specified endpoint blend at the specified hydrogen content.

Separate auxiliary reports are shown which give the properties of the total middle distillate pool (which include cracked olefinic stocks which are normally diverted from jet fuel), and the residual fuel oil pool.

A summary material balance report shows the disposition of mass, sulfur, nitrogen and hydrogen between feed streams and final products*. Overall recoveries are given at the bottom of this report. Note that the volumetric recovery is reasonable for a refinery of the specified configuration. The weight recovery is less than 100.0 of weight percent, reflecting the fact that weight balances for the individual process units have not been forced through the proration of discrepancies. The lower sulfur and nitrogen recoveries are due almost entirely to crude unit imbalances which reflect inconsistencies in the basic crude assay data. In general, basic data of this type has not been adjusted through internal program computations because to do so would cause the program user to lose sight of those data base areas which could be improved. Sulfur and nitrogen balances for the downstream units, however, provide

* The middle distillate blend reported here is the balance remaining after the specified jet fuel blend has been made.

were obtained by a general review of today's petroleum refining costs and are expressed in current 1977 dollars, with no built-in inflation. Crude prices, product realizations, electricity cost and investment carrying charge must be input since they are specific to a given situation.

Additional information provided in the front of the report printout show the input data cards as punched. The items appearing under the headers &CDATA, &UDATA and &UDATA1 are for illustrative purposes only -- data input under these cards allows for user directed changes to any of the data base values contained in the crude oil assay data base subroutine (CBASE) and the process unit data base subroutine (UBASE). This capability can prove valuable for simulating specific refining situations.

2.4 Program Logic

An overall block diagram describing the logic of the Gordian Refinery Simulation Model is shown in Exhibit 2. A brief functional description comprising the Gordian Refinery Simulation Model follows:

MAIN PROGRAM - The main program blends crude oil properties, calculates the refinery volumetric balance, calculates the overall refinery material balance, issues summary reports and sets up the subroutine calling sequence.

BLOCK DATA - Contains initialization data used throughout the program and refinery process unit cost data used by the economic subroutine.

CONAPI - Converts from API to specific gravity and back as required.

ISTN - Sets stream number identities used by the main program and the report subroutines.

CBASE - Contains the crude assay data base.

UBASE - Contains the refinery process unit yield and stream quality data base.

MATCLC - Performs all material balance calculations required for the weight, sulfur, nitrogen and hydrogen balance around each of the refinery process units.

INITB - Initializes default input value for each base case run.

UNTREP - The report writer subroutine for the individual process unit material balances.

UNTENR - The report writer subroutine for energy usage consumed by each refinery process unit.

ECON - Does the refinery economics calculation and outputs summary reports.

HYDCAL - Calculates the hydrogen content of every refinery process stream as a function of specific gravity and mean average boiling point -- unless a value has been pre-specified in UBASE or input.

INITV - Initializes intermediate program variables.

BLDARY - Sets up blending stream proprieties for each stream used in jet fuel, middle distillate and residual fuel blends.

BLENDF - Contains the calculation sequence for each of the jet fuel blend combinations and the middle distillate and residual fuel oil blends.

SSORT1- Sorts jet fuel blending components according to their hydrogen content ranking.

BLDREP - The report writer subroutine for turbine fuel, middle distillate and residual fuel oil blends.

BPROP - Calculates blend properties and contains freezing point and smoke point blending correlations.

SSORT - Sorts blend components by sulfur content ranking - used for calculating middle distillate and residual fuel oil blend combinations.

BMAX - This subroutine calculates the maximum quantity of jet fuel blend production of a specified hydrogen content, or maximum middle distillate or residual fuel of a specified sulfur content.

A more detailed and comprehensive description of the programming aspects of the Gordian Refinery Simulation Model is given in Volume II (NASA CR-135334) and Volume III (NASA CR-135335).

2.5 Summary of Model Options and Flexibility

Any combination of crude oils represented in the Crude Assay subroutine may be selected by specifying their code number and the charge volume of each crude; including shale oil and coal liquefaction products. If the feed to the refinery contains crude oils which are not represented in the Crude Assay subroutine, then the yields and properties of these crudes may be input directly into the model along with their volumes. If individual refinery charge streams, such as purchased gas oil, distillate cutter stocks, and naphthas are a part of the refinery charge, these may also be specified by giving their feed volumes and stream properties.

The volumes of up to four separate "imported" fuel oil blending components (kerosene, diesel, gas oil, and residuum) may be specified along with their properties in order to simulate the refinery operation. These components enter directly into fuel oil blending without being mixed with other streams.

The block flow diagram of the refinery processing units is shown as Exhibit 3. The following process units may be specified when defining the refinery process unit configuration:

(1) Atmospheric crude distillation (petroleum-based, shale oil, coal oil)

(2) Vacuum crude oil distillation (petroleum-based, shale oil, coal oil)

(3) Catalytic gas oil cracking

(4) Thermal gas oil cracking

(5) Middle distillate desulfurizer

(6) Kerosene Hydrotreater (separate units for petroleum stocks, coal based and shale oil stocks)

(7) Fluid coking

(8) Vacuum bottoms visbreaking

(9) Middle distillate and gas oil hydrocracking (separate gas oil hydrocracking units for petroleum stocks, coal-based and shale oil stocks)

(10) Catalytic naphtha reforming

(11) Alkylation

(12) Polymerization

(13) Butane isomerization

(14) Hydrogen production

Variables which serve to describe internal refinery operations are also a part of the input. The catalytic cracker severity (percentage conversion), the naphtha reformer severity (octane), the type of petroleum-based gas oil hydrocracking operation (gasoline versus distillate production, and the severity of shale oil and coal oil hydrocracking and hydrotreating operation must be specified either directly (or will be by default) if these units are included in the overall refinery configuration. In a complex refinery where internal streams such as diesel oil and coker and vacuum gas oil have alternative dispositions, the fraction of each such stream going to alternative refinery process units may be specified.If fractional dispositions are not specified, the default is to prorate internal refinery stream to alternative down stream units by the ratio of their stated capacities.

In some instances it may be desirable to replace the typical refinery process yields contained in the Refinery Process Yield subroutine with yield and quality numbers which more exactly represent a particular refinery. This could occur if a particular refinery was atypical in some respects or if a rather close match of unusual refinery operations was desired. For this reason, the option exists to override any of the data base values contained in the Refinery Process Yield subroutine by specifying them in the input.

With regard to the refinery process unit capacities, it would be unusual for a specified unit throughput to exactly match the volume of an intermediate refinery stream. If the unit is undersized, the excess feed stock is blended off or is downgraded. If the unit is oversized, the slack processing capacity is reported. Both situations are handled automatically by the program logic.

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3.0 REQUIRED MODEL INPUTS

3.1 General Rules for Fortran Namelist Input

Punched card input is read directly by the Fuel Blending Model using the Fortran Namelist feature. This feature allows for a "free format" type of input whereby the data may be input in any sequence. However, certain input rules must be observed and they are listed below.

- The first card heading up the input for a new run or case must contain an ampersand (&) in column 2 followed by the name of the data list (see Section 3.2 for the instructions for specifying data lists for the Gordian Simulation Model).
- A variable name must be completed on a card, but may begin in any location from column 2 onwards. Card column 1 is never to be used for any purpose.
- More than one variable name and more than one data entry may appear on a card, the only requirement being that they be separated by commas.

  For example:

  FCC=30000.0, GASOIL=2000.0, GOHYC=5000.0, MODE=2, is a legitimate card entry with FCC starting in card column 2 onwards. As shown above, the = sign must immediately follow the symbolic variable name and there may be no blank space appearing within the symbolic variable name. However, the data values following the equal sign may be spaced on the card, as long as the last item entered on a data card is always a comma.

For example:

FCC= 30000.0, GASOIL= 2000.0,

GOHYC= 5000.0, MODE= 2,

are legitimate entries for two successive input cards.

- Elements of input arrays, such as the array of crude oil volume feed rate, must be input with the array element number indicated in parentheses. For example:

  CV(8)= 50000.0, CV(10)= 40000.0,

  would indicate fifty and forty thousand barrels per day of crude oils #8 and #10, respectively. No intervening blanks should appear in designating an input variable of this type. For example, do <u>not</u> input

  CV (8) = 50000.0,

- Data types must be respected. For example:

  MODE=2, ICASE=1, TITLE= 'TEST RUN', FCC= 30000.0, CV(1)=50000.0, is correct in every respect. The four variable types used in this program are:

  - Literal variables, which appear between quotation marks and which may consist of any combination of alphabetic or numeric information. The only variable of this type appearing in this program is TITLE, which is used to provide a run or case title.
  - Integer variables (such as ICASE and MODE) which are always followed by whole numbers, without a decimal point.

- Real variables (such as FCC=30000.0, VGOFCC=0.45,) which are followed by numbers containing decimal points.
- Real variables, which are also array elements (such as CV(1)=50000.0, CV(10)=20000.0, CA(2,22)=0.03

- The last card denoting the end of an input data list must contain &END, beginning in column 2 with no intervening blanks.

3.2 Detailed Description of Specific Inputs

The following section describes the program input using the FORTRAN namelist feature, item by item. If a particular input, or a group of inputs, is not relevant to the problem at hand, they may be omitted. A list of the program default values for each specific input is given in Section 3.3. With a few exceptions, the program default values are usually zero.

In this section the data type and the appropriate units are given for each input variable. The following abbreviations are used for units:

BPD	Barrels per day. These are on a calendar day basis (BPCD). The program makes stream day adjustments based on the value of the input stream factor STRF.
MMSCFD	Millions of standard cubic feet per day.

The input data stream sequence is organized as follows:

```
&CDATA ... crude oil assay data base changes (optional)
&END
&UDATA ... process unit data base changes (optional)
&END
```

```
&UDATA1 ... process unit data base changes (optional)
&END
&PDATA ... input defining the refinery feed, product and process
&END   unit size characteristics (required)
```

While crude oil and process unit data base changes are optional, the header cards (which contain an ampersand in column 2) <u>are required</u> at the beginning of the input data stream run sequence, even if no change cards are input.

The input data items appearing between the headers &PDATA and &END are described in sections 3.2.1, 3.2.2, and 3.2.7 to 3.2.9. Default values are automatically established within the program, as discussed in section 3.3; hence input data are required only where different from the default values. The optional crude oil assay data items appearing between the headers &CDATA and &END are described in section 3.2.3. Optional process data change items appearing between &UDATA and &END are those described in sections 3.2.4 and in section 3.2.5 except for viscosity and research octane variables. Optional process data change items appearing between &UDATA1 and &END are the viscosity and octane variables and the items described in section 3.2.6.

3.2.1 Title and Case Study Feature

Name	Type	Units	Description
TITLE	Literal	-	The run or case title which will appear at the top of each output page. Up to 70 alpha-numeric characters may be used.
ICASE	Integer	-	The case study indicator. If not entered it is assumed that the run is a "stand alone run" with no fixed relation to preceding or succeeding runs. Input ICASE=1 for the starting base case of a case study sequence. Input ICASE=2 for a subject case to be dependent on the starting case. Input ICASE=3 for the final case of a case study sequence. A case study sequence may be followed by stand alone runs or a new case study sequence can be initiated, if desired. The program logic is such that all subject case changes are made to the starting base case of a case study sequence. Therefore, subject case changes are not additive in nature.

3.2.2 Process Unit Capacities, Modes of Operation and Internal Stream Disposition

Name	Type	Units	Description
CV(N)	Real Array	BPD	The crude unit charge rate of crude N, where the code integer N applies to a specific crude. A list of those crudes currently represented in the model is given in Exhibit 4, attached.
VACD	Real	BPD	The vacuum distillation capacity. For petroleum-based, expressed as reduced crude feedrate.
VACS	Real	BPD	The vacuum distillation capacity for shale oil based crude.
VACC	Real	BPD	The vacuum distillation capacity for coal oil based synthetic crude.
FCC*	Real	BPD	The refinery catalytic cracking capacity, expressed as total gas oil feedrate (fresh feed).
CONV	Real	Volume Percent	The conversion (percentage gas oil disappearance) of the fluid catalytic cracking unit.

* Presently available data is limited to petroleum based fractions. The shale and coal oil hydroprocessing units should be specified for processing those species.

Name	Type	Units	Description
ALKY	Real	BPD	The refinery alkylation unit capacity expressed as total alkylate product.
POLY	Real	BPD	The refinery polymerization unit capacity expressed as polymer product rate.
MDDES*	Real	BPD	The refinery middle distillate desulfurizer feed capacity expressed as total feed rate.
GODES*	Real	BPD	The refinery gas oil desulfurizer feed capacity expressed as total feed rate.
SOKHT	Real	BPD	The refinery shale oil kerosene hydrotreater capacity expressed as kerosene feed rate.
SVSKHT	Integer	-	The designated mode of operation of the shale oil kerosene hydrotreater. Enter 1 for mild, 2 for intermediate, and 3 for severe operation.
COKHT	Real	BPD	The refinery coal oil kerosene hydrotreater capacity expressed as kerosene feed rate.
SVCKHT	Integer	-	The designated mode of operation of the coal oil kerosene hydrotreater. Enter 1 for mild, 2 for intermediate, and 3 for severe operation.
SGOHYC	Real	BPD	The refinery shale oil gas oil hydrocracker capacity expressed as total feed rate.
SVSGHT	Integer	-	The designated mode of operation of the shale oil gas oil hydrocracker. Enter 1 for mild, 2 for intermediate, and 3 for severe operation.
CGOHYC	Real	BPD	The refinery coal oil gas oil hydrocracker capacity expressed as total feed rate.
SVCGHT	Integer	-	The designated mode of operation of the coal oil gas oil hydrocracker. Enter 1 for mild, 2 for intermediate, and 3 for severe operation.
COKER	Real	BPD	The refinery coker unit capacity expressed as vacuum bottoms feed rate.
VB	Real	BPD	The refinery visbreaker unit capacity expressed as vacuum bottoms feed rate.
TCC	Real	BPD	The refinery thermal cracker unit capacity expressed as gas oil feed rate.

* Specify these units for processing petroleum based fractions. Specify the shale and coal oil hydroprocessing units for processing those species.

Name	Type	Units	Description
MDHYC*	Real	BPD	The refinery middle distillate hydrocracker capacity expressed as total feed rate.
GOHYC*	Real	BPD	The refinery petroleum gas oil hydrocracker capacity expressed as total feed rate.
MODE	Integer	-	The designated mode of operation of the refinery gas oil hydrocracker. Enter MODE=1 for a gasoline operation and MODE=2 for a middle distillate operation.
BI	Real	BPD	The refinery butane isomerization capacity expressed as the normal butane feed rate.
HYD	Real	MMSCFD	The refinery hydrogen unit capacity expressed as the hydrogen production rate.
REF	Real	BPD	The refinery catalytic naphtha reformer capacity expressed as total naphtha feed rate.
REFRON	Real	Research Octane No., Clear	The catalytic reformer severity expressed as the clear research octane number of the total platformate.
HTKERO	Real	BPD	The refinery petroleum kerosene hydrotreater capacity expressed as the kerosene feed rate.

Internal Stream Dispositions

If alternative destinations exist for any of the internal refinery streams, the following inputs serve to define the fraction of the stream being routed to each alternative process unit (values for these variables should not be input for a given stream if the refinery configuration is such that multiple destinations do not exist). The programmed default is to prorate stream volume by the ratio of available downstream process unit capacities.

* Specify these units only for processing petroleum based fractions. Specify the shale and coal oil hydroprocessing units for processing those species.

If the total of the sum of the volume fractions going to alternative destinations for a particular stream are specified at less than 1.0, the balance of that stream is assumed to go directly to fuel oil blending.

For the low-boiling internal streams (methane, ethane, propane, butanes, and the corresponding olefins), distribution priorities are prescribed. Alkylation has the first priority for isobutane and butylene. The polymerization unit uses propylene first, and if additional capacity is left, is uses the excess butylene. For hydrogen production, propane is used first and then ethane and lighter. The overall hydrogen requirements of the refinery are filled by first the hydrogen produced by the catalytic reformer and then, if needed, by hydrogen from the hydrogen plant. The balance of the low-boiling streams not used internally goes to fuel gas and LPG.

Name	Type	Units	Description
DSLDES	Real	Volume Fraction	The volume fraction of the refinery diesel stream going to the middle distillate desulfurizer.
DSLMDH	Real	Volume Fraction	The volume fraction of the refinery diesel stream going to the middle distillate hydrocracker.
LCODES	Real	Volume Fraction	The volume fraction of light catalytic cycle oil going to the middle distillate desulfurizer.
LCOMDH	Real	Volume Fraction	The volume fraction of light catalytic cycle oil going to the middle distillate hydrocracker.
VGODES	Real	Volume Fraction	The volume fraction of the refinery gas oil stream going to gas oil desulfurization.
VGOHYC	Real	Volume Fraction	The fraction of the above stream going to gas oil hydrocracking.
VGOFCC	Real	Volume Fraction	The fraction of the above stream going to gas oil catalytic cracking.
VGOTCC	Real	Volume Fraction	The fraction of the above stream going to gas oil thermal cracking.

CGODES COGOHY CGOFCC	Real	Volume Fractions	These three input variables denote the volume fraction of total coker gas oil to the respective destinations listed above.
VBTMVB	Real	Volume Fraction	The volume fraction of vacuum bottoms going to the visbreaker.
VBTMCO	Real	Volume Fraction	The volume fraction of vacuum bottoms going to the coker.
SLKKHT	Real	Volume Fraction	The volume fraction of light kerosene (400 to 525°F EP) going to the shale oil kerosene hydrotreater.
SHKKHT	Real	Volume Fraction	The volume fraction of heavy kerosene (525 to 650°F EP) going to the shale oil kerosene hydrotreater.
CLKKHT	Real	Volume Fraction	The volume fraction of light kerosene (400 to 525° F EP) going to the coal oil kerosene hydrotreater.
CHKKHT	Real	Volume Fraction	The volume fraction of heavy kerosene (525 to 650°F EP) going to the coal oil kerosene hydrotreater.
SGOHC	Real	Volume Fraction	The volume fraction of gas oil going to the shale oil gas oil hydrocracker.
CGOHC	Real	Volume Fraction	The volume fraction of gas oil going to the coal oil gas oil hydrocracker.

3.2.3 Crude Assay Information

The following input variables relate to the crude oil assay information which may be entered directly as input. The values may apply to entirely new feeds or may be used to override crude oil assay information currently stored in the model. The crude assay data changes are entered first in the sequence between the &CDATA and &END header cards.

Crude oil assay code numbers 1 through 26 are reserved for crude oil assays presently stored within the program. Code numbers 27 through 35 may be used to describe crude oils and feeds which are not in the permanent data base. A list of data base crude oils is given in Exhibit 4.

Refinery charge streams such as gas oils may be specified by entering a fractional gas oil yield of 1.0 for the crude assay, along with the gas oil properties. The remaining crude oil assay values are not to be input in this instance since the gas oil data has fully described the refinery charge stream. This input data philosophy may be extended to any type of refinery charge stream, naphtha, kerosene, diesel, etc., which is imported to the refinery for processing within the normal plant sequence.

Name	Type	Units	Description
CA(N,1)	Real Array	Volume Fraction (BBL/BBL)	Crude assay yield of ethane and lighter for crude N.
CA(N,2)	"	"	Yield of propane.
CA(N,3)	"	"	Yield of isobutane.
CA(N,4)	"	"	Yield of normal butane.
CA(N,5)	"	"	Yield of pentane.
CA(N,6)	"	"	Yield of light straight run gasoline. (IBP-250°F)
CA(N,7)	"	"	Yield of heavy straight run naphtha-reformer feed. (250 to 400°F)
CA(N,8)	"	"	Yield of light kerosene (400 to 525°F).
CA(N,9)	"	"	Yield of heavy kerosene (525 to 650°F).
CA(N,10)	"	"	Yield of vacuum gas oil (650 to 1,050°F EP).
CA(N,11)	"	"	Yield of vacuum bottoms (1,050°F +).
CA(N,12)	"	Degrees API Gravity	Crude oil API gravity.
CA(N,13)	"	"	Light straight run API gravity.
CA(N,14)	"	"	Heavy straight run API gravity.
CA(N,15)	"	"	Light kerosene API gravity.
CA(N,16)	"	"	Heavy kerosene API gravity.

CA(N,17)	"	"	Vacuum gas oil API gravity.
CA(N,18)	"	"	Vacuum bottoms API gravity.
CA(N,19)	"	Weight Percent	Crude oil sulfur content.
CA(N,20)	"	"	Light straight run sulfur content.
CA(N,21)	"	"	Heavy straight run sulfur content.
CA(N,22)	Real Array	Weight Percent	Light kerosene sulfur content.
CA(N,23)	"	"	Heavy kerosene sulfur content.
CA(N,24)	"	"	Vacuum gas oil sulfur content.
CA(N,25)	"	"	Vacuum bottoms sulfur content.
CA(N,26)	"	"	Crude oil nitrogen content.
CA(N,27)	"	"	Light straight run nitrogen content.
CA(N,28)	"	"	Heavy straight run nitrogen content.
CA(N,29)	"	"	Light kerosene nitrogen content.
CA(N,30)	"	"	Heavy kerosene nitrogen content.
CA(N,31)	"	"	Vacuum gas oil nitrogen content.
CA(N,32)	"	"	Vacuum bottoms nitrogen content.
CA(N,33)	"	"	Crude oil hydrogen content.
CA(N,34)	"	"	Light straight run hydrogen content.
CA(N,35)	"	"	Heavy straight run hydrogen content.
CA(N,36)	"	"	Light kerosene hydrogen content.
CA(N,37)	"	"	Heavy kerosene hydrogen content.
CA(N,38)	"	"	Gas oil hydrogen content.
CA(N,39)	"	"	Vacuum bottoms hydrogen content.
CA(N,40)	"	Viscosity Blending Index	Light kerosene viscosity index at 210°F.
CA(N,41)	"	"	Heavy kerosene viscosity index at 210°F
CA(N,42)	"	"	Gas oil viscosity index at 210°F.

CA(N,43)	"	"	Vacuum bottoms viscosity index at 210°F.
CA(N,44)	Real Array	Weight Percent	Light kerosene paraffin content.
CA(N,45)	"	"	Light kerosene naphthene content.
CA(N,46)	"	"	Light kerosene aromatics content.
CA(N,47)	"	"	Heavy kerosene paraffin content.
CA(N,48)	"	"	Heavy kerosene naphthene content.
CA(N,49)	"	"	Heavy kerosene aromatics content.
CA(N,50)	"	°F	Light kerosene freezing point.
CA(N,51)	"	°F	Heavy kerosene freezing point.
CA(N,52)	"	mm	Light kerosene smoke point.
CA(N,53)	"	mm	Heavy kerosene smoke point.
CA(N,54)	"	BTU/#	Crude oil heat of combustion.
CA(N,55)	"	"	Light kerosene heat of combustion.
CA(N,56)	"	"	Heavy kerosene heat of combustion.
CA(N,57)	"	-	Species indicator 1.0 = Coal Oil 2.0 = Shale Oil 3.0 = Petroleum

Note: N corresponds to the crude oil code number given in Exhibit 4. The boiling point distillation ranges of the liquid crude oil cuts are given in parentheses and correspond to ASTM D-86 boiling points. The Viscosity Blend Index referred to is described in Exhibit 6.

3.2.4 Process Unit Data

The following input variables affect the internally stored program values of the process unit yields and utility consumptions. It is only necessary to input these variables when it is desired to replace the data stored for any of the process units with values of the user's choice. Changes to the process unit data base are entered second in the input sequence, after the crude assay data base changes between &UDATA and &END header cards.

All of the input variables listed below are elements of real arrays. The units are fractional barrels of the particular stream yielded per barrel of the indicated feed stream. Coke, hydrogen, refinery gas, and process unit steam and fuel consumption are in barrels of fuel oil equivalent per barrel of feed.* Electricity usage is in kilowatt hours (KWH) per barrel of process unit feed. If the process unit produces steam as opposed to using it, a negative number should be entered for steam consumption.

As may be seen from analyzing the input variable names listed below, all of the product streams have been assigned characteristic code numbers. These are listed in Exhibit 5.

Crude Unit, Per Barrel of Crude Oil Feed	Petroleum	Shale Oil	Coal Oil
Steam consumption	CUPYLD(1)	CUSYLD(1)	CUCYLD(1)
Fuel consumption	CUPYLD(2)	CUSYLD(2)	CUCYLD(2)
Electricity consumption	CUPYLD(3)	CUSYLD(3)	CUCYLD(3)

	Visbreaker (per barrel of vacuum bottom feed)	Coker (per barrel of vacuum bottom feed)
Steam consumption	VBYLD(1)	COYLD(1)
Fuel consumption	VBYLD(2)	COYLD(2)
Electricity consumption	VBYLD(3)	COYLD(3)
Refinery gas yield	VBYLD(5)	COYLD(5)
Propane yield	VBYLD(6)	COYLD(6)
Propylene yield	VBYLD(7)	COYLD(7)
Isobutane yield	VBYLD(8)	COYLD(8)
Normal butane yield	VBYLD(9)	COYLD(9)
Butylene yield	VBYLD(10)	COYLD(10)
Light gasoline	VBYLD(31)	COYLD(31)
Heavy gasoline	VBYLD(32)	COYLD(32)
Total gas oil	VBYLD(35)	COYLD(35)
Coke	-	COYLD(36)
Pitch	VBYLD(51)	-

* 6,050,000 BTU per barrel fuel oil equivalent (BFOE), corresponding to the net heating value.

Catalytic Cracker Yields

	@ low conversion	@ high conversion
	per barrel of vacuum gas oil feed	
Steam consumption	CGYLDL(1)	CGYLDH(1)
Fuel consumption	CGYLDL(2)	CGYLDH(2)
Electricity consumption	CGYLDL(3)	CGYLDH(3)
Refinery gas yield	CGYLDL(5)	CGYLDH(5)
Propane yield	CGYLDL(6)	CGYLDH(6)
Propylene yield	CGYLDL(7)	CGYLDH(7)
Isobutane yield	CGYLDL(8)	CGYLDH(8)
Normal butane yield	CGYLDL(9)	CGYLDH(9)
Butylene yield	CGYLDL(10)	CGYLDH(10)
Cracked gasoline	CGYLDL(37)	CGYLDH(37)
Light cycle oil	CGYLDL(38)	CGYLDH(38)
Cracker bottoms	CGYLDL(39)	CGYLDH(39)
	per barrel of coker gas oil feed	
Steam consumption	CCYLDL(1)	CCYLDH(1)
Fuel consumption	CCYLDL(2)	CCYLDH(2)
Electricity consumption	CCYLDL(3)	CCYLDH(3)
Refinery gas yield	CCYLDL(5)	CCYLDL(5)
Propane yield	CCYLDL(6)	CCYLDH(6)
Propylene yield	CCYLDL(7)	CCYLDH(7)
Isobutane yield	CCYLDL(8)	CCYLDH(8)
Normal butane yield	CCYLDL(9)	CCYLDH(9)
Butylene yield	CCYLDL(10)	CCYLDH(10)
Cracked gasoline	CCYLDL(37)	CCYLDH(37)
Light cycle oil	CCYLDL(38)	CCYLDH(38)
Cracker bottoms	CCYLDL(39)	CCYLDH(39)

CONVL Low Catalytic Cracker conversion -- volume percent of gas oil disappearance.

CONVH High Catalytic Cracker conversion -- volume percent of gas oil disappearance

Thermal Cracker Yields

	per barrel of vacuum gas oil feed
Steam consumption	TCCYLD(1)
Fuel Consumption	TCCYLD(2)
Electricity consumption	TCCYLD(3)
Refinery gas yield	TCCYLD(5)
Propane yield	TCCYLD(6)
Propylene yield	TCCYLD(7)
Isobutane yield	TCCYLD(8)
Normal Butane yield	TCCYLD(9)
Butylene yield	TCCYLD(10)
Cracked gasoline	TCCYLD(37)
Thermal fuel	TCCYLD(52)

Alkylation Unit Yields

	per barrel of butylene feed
Steam consumption	ALYLD(1)
Fuel consumption	ALYLD(2)
Electricity consumption	ALYLD(3)
Iso Butane consumption	ALYLD(8) (Enter a negative number)
Light Alkylate yield	ALYLD(21)
Heavy Alkylate yield	ALYLD(22)

Polymerization Unit Yields

	per barrel of butylene feed	per barrel of propylene feed
Steam consumption	POYLDB(1)	POYLDP(1)
Fuel consumption	POYLDB(2)	POYLDP(2)
Electricity consumption	POYLDB(3)	POYLDP(3)
Normal butane yield	POYLDB(9)	POYLDP(9)
Polymer gasoline yield	POYLDB(23)	POYLDP(23)

Middle Distillate Desulfurizer Yields

	per barrel of diesel feed	per barrel of light cycle oil feed
Steam consumption	DDYLDD(1)	DDYLDL(1)
Fuel consumption	DDYLDD(2)	DDYLDL(2)
Electricity consumption	DDYLDD(3)	DDYLDL(3)
Hydrogen consumption*	DDYLDD(4)	DDYLDL(4)
Refinery gas yield	DDYLDD(5)	DDYLDL(5)
Desulfurized product yield	DDYLDD(41)	DDYLDL(40)
Gasoline yield	DDYLDD(45)	DDYLDL(45)

Gas Oil Desulfurizer Yields

	per barrel of vacuum gas oil	per barrel of total coker gas oil
Steam consumption	GDYLDG(1)	GDYLDC(1)
Fuel consumption	GDYLDG(2)	GDYLDC(2)
Electricity consumption	GDYLDG(3)	GDYLDC(3)
Hydrogen consumption*	GDYLDG(4)	GDYLDC(4)
Refinery gas yield	GDYLDG(5)	GDYLDC(5)
Distillate product yield	GDYLDG(43)	GDYLDC(46)
Desulfurized gas oil yield	GDYLDG(44)	GDYLDC(47)

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* Enter a negative number for hydrogen in all processes where hydrogen is consumed.

Middle Distillate Hydrocracker Yields

	per barrel of diesel feed	per barrel of light cycle oil feed
Steam consumption	DHYLDD(1)	DHYLDL(1)
Fuel consumption	DHYLDD(2)	DHYLDL(2)
Electricity consumption	DHYLDD(3)	DHYLDL(3)
Hydrogen consumption*	DHYLDD(4)	DHYLDL(4)
Refinery gas yield	DHYLDD(5)	DHYLDL(5)
Propane yield	DHYLDD(6)	DHYLDL(6)
Iso Butane yield	DHYLDD(8)	DHYLDL(8)
Normal Butane yield	DHYLDD(9)	DHYLDL(9)
Pentanes yield	DHYLDD(13)	DHYLDL(13)
Hydrocrackate yield	DHYLDD(14)	DHYLDL(14)

Gas Oil Hydrocracker Yields

	per barrel of vacuum gas oil feed		per barrel of total coker gas oil feed	
	Gasoline Mode	Distillate Mode	Gasoline Mode	Distillate Mode
Steam consumption	GGYLDG(1)	GMYLDG(1)	GGYLDC(1)	GMYLDC(1)
Fuel consumption	GGYLDG(2)	GMYLDG(2)	GGYLDC(2)	GMYLDC(2)
Electricity consumption	GGYLDG(3)	GMYLDG(3)	GGYLDC(3)	GMYLDC(3)
Hydrogen consumption*	GGYLDG(4)	GMYLDG(4)	GGYLDC(4)	GMYLDC(4)
Refinery fuel gas yield	GGYLDG(5)	GMYLDG(5)	GGYLDC(5)	GMYLDC(5)
Propane yield	GGYLDG(6)	GMYLDG(6)	GGYLDC(6)	GMYLDC(6)
Iso Butane yield	GGYLDG(8)	GMYLDG(8)	GGYLDC(8)	GMYLDC(8)
Normal Butane yield	GGYLDG(9)	GMYLDG(9)	GGYLDC(9)	GMYLDC(9)
Light Hydrocrackate yield	GGYLDG(15)	GMYLDG(15)	GGYLDC(15)	GMYLDC(15)
Heavy Hydrocrackate yield	GGYLDG(14)	GMYLDG(14)	GGYLDC(14)	GMYLDC(14)
Distillate yield	GGYLDG(17)	GMYLDG(17)	GGYLDC(48)	GMYLDC(48)

* Enter a negative number for hydrogen in all processes where hydrogen is consumed.

Catalytic Reformer Yields

	per barrel of naththa feed	
	@ Low Severity	@ High Severity
Steam consumption	RYLDLN(1)	RYLDHN(1)
Fuel consumption	RYLDLN(2)	RYLDHN(2)
Electricity consumption	RYLDLN(3)	RYLDHN(3)
Hydrogen yield*	RYLDLN(4)	RYLDHN(4)
Refinery gas yield	RYLDLN(5)	RYLDHN(5)
Propane yield	RYLDLN(6)	RYLDHN(6)
Iso Butane yield	RYLDLN(8)	RYLDHN(8)
Normal Butane yield	RYLDLN(9)	RYLDHN(9)
Light Platformate yield	RYLDLN(18)	RYLDHN(18)
Heavy Platformate yield	RYLDLN(19)	RYLDHN(19)
C-5, C-6 Feed Prep yield	RYLDLN(12)	RYLDHN(12)
Heavy-Naptha (Feed Prep yield)	RYLDLN(16)	RYLDHN(16)

For Heavy hydrocrackate reformer feed, use the same input sequence but with RYLDLH(_) and RYLDHH(_).

For Heavy coker or visbreaker naphtha reformer feed, use the same input sequence but with RYLDLC(_) and RYLDHC(_).

RONLOW The debutanized total platformate clear research octane number corresponding to low reformer severity.

RONHI The debutanized total platformate clear research octane number corresponding to high reformer severity.

Hydrogen Plant Yields

	per barrel FOE from refinery gas	per liquid bbl from propane
Steam consumption	HYYLDG(1)	HYYLDP(1)
Fuel consumption	HYYLDG(2)	HYYLDP(2)
Electricity consumption	HYYLDG(3)	HYYLDP(3)
Hydrogen production**	HYYLDG(4)	HYYLDP(4)

* Enter a positive number here in barrels FOE hydrogen per barrel of feed stream (95% pure hydrogen) since there is a production rather than a consumption of hydrogen.

** A positive number.

Butane Isomerizer

	per barrel normal butane feed
Steam consumption	BIYLD(1)
Fuel consumption	BIYLD(2)
Electricity consumption	BIYLD(3)
Refinery gas yield	BIYLD(5)
Propane yield	BIYLD(6)
Iso Butane yield	BIYLD(8)
Pentanes yield	BIYLD(11)

Petroleum Kerosene Hydrotreater Yields

	per barrel of kerosene feed
Steam consumption	HKYLD(1)
Fuel consumption	HKYLD(2)
Electricity consumption	HKYLD(3)
Hydrogen consumption	HKYLD(4)
Refinery gas yield	HKYLD(5)
Hydrotreater gasoline yield	HKYLD(45)
Hydrotreater kerosene	HKYLD(50)

Shale Oil Kerosene Hydrotreater Yields

	per bbl of light kerosene feed (400 to 525°F EP)	per bbl of heavy kerosene feed (525 to 650°F EP)
	Low Severity	Low Severity
Steam consumption	SSKYL1(1)*	SSKYH1(1)*
Fuel consumption	SSKYL1(2)	SSKYH1(2)
Electricity consumption	SSKYL1(3)	SSKYH1(3)
Hydrogen consumption*	SSKYL1(4)	SSKYH1(4)
Refinery fuel gas yield	SSKYL1(5)	SSKYH1(5)
Hydrotreated kerosene	SSKYL1(58)	SSKYH1(59)

* Note: For intermediate and high severity operations, replace the numeral 1 (i.e., the sixth character) by 2 Or 3, respectively.

Coal Oil Kerosene Hydrotreater Yields

	per bbl of light kerosene feed (400 to 525°F EP)	per bbl of heavy kerosene feed (525 to 650°F EP)
	Low Severity	Low Severity
Steam consumption	COKYL1(1)*	COKYH1(1)*
Fuel consumption	COKYL1(2)	COKYH1(2)
Electricity consumption	COKYL1(3)	COKYH1(3)
Hydrogen consumption**	COKYL1(4)	COKYH1(4)
Refinery fuel gas yield	COKYL1(5)	COKYH1(5)
Hydrotreated kerosene	COKYL1(64)	COKYH1(65)

Shale and Coal Oil for Oil Hydrocrackers

	Shale Oil	Coal Oil
	Low Severity	Low Severity
Steam consumption	SSGY1(1)*	COGY1(1)*
Fuel consumption	SSGY1(2)	COGY1(2)
Electricity consumption	SSGY1(3)	COGY1(3)
Hydrogen consumption*	SSGY1(4)	COGY1(4)
Refinery fuel gas yield	SSGY1(5)	COGY1(5)
Propane yield	SSGY1(6)	COGY1(6)
Isobutane yield	SSGY1(8)	COGY1(8)
N-butane yield	SSGY1(9)	COGY1(9)
Light hydrocrackate (250°F EP)	SSGY1(15)	COGY1(15)
Heavy hydrocrackate (400°F EP)	SSGY1(14)	COGY1(14)
Light hydrotreated kerosene (400° - 525°F EP)	SSGY1(58)	COGY1(64)
Heavy hydrotreated kerosene (525° - 650°F EP)	SSGY1(59)	COGY1(65)
Hydrotreated gas oil (650°F +)	SSGY1(60)	COGY1(66)

* Note: For intermediate and high severity operations, replace the numeral 1 (i.e., the fifth character) by 2 or 3, respectively.

3.2.5 Intermediate Stream Properties

The following input variables relate to the properties of the individual streams which are yielded from the various refinery process units. They are not required as input unless it is desired to replace the data base values contained within the program. Input items described

** Enter a negative number.

in this section are included between the headers &UDATA and &END, except for viscosity (VIS or V) and octane (OC) properties, which are included between &UDATA1 and &END.

For aviation turbine fuel and fuel oil blending components the properties include the API gravity, sulfur content, nitrogen content and the viscosity blending index value. Hydrogen contents are calculated from a correlation of specific gravity and mid-boiling points except for select streams where a hydrogen content may be specified to override the calculated value. Gasoline blending component properties also include the Research (blending) Octane Number for 0 and 3 ml of TEL.

The viscosity blending numbers used must correspond to Saybolt Seconds at 210 degrees Fahrenheit so that they are consistent with the values contained in the model. A viscosity conversion chart is attached as Exhibit 6.

With the exceptions to be noted, the input variables are all elements of real arrays. The butane blending octane numbers are (non-array) real numbers.

A consistent logic applies to the naming of intermediate stream properties. This logic is illustrated below using the kerosene hydrotreater unit as an example:

Description	Array	Remarks
Yield Array	HKYLD(I)	See section 2.2.4 for details.
API Gravity	HKAPI(I)	For pentanes and heavier streams.
Sulfur Distribution	HKSUL(I)	Fractional sulfur distribution among products.*
Nitrogen Distribution	HKNIT(I)	Fractional nitrogen distribution among products.*

* These should add to 1.0, unless there are external losses, such as loss of sulfur from the combustion of catalytic coke.

Hydrogen Content	HKHYD(I)	Hydrogen content, wt. %
Viscosity Blending Number (input between &UDATA1 and &END)	HKVIS(I)	For kerosene and heavier streams.

The above logic is used to name the properties of streams for all of the process units using the three-character set YLD and which are ennumerated in Section 3.2.4. The character set YLD is replaced by API, SUL, NIT, HYD or VIS to input the appropriate property. The letter "I" shown under the heading Array refers to the stream identification number provided in Section 3.2.4 for process units employing a single character to describe the yield array. The letter Y is replaced by A, S, N and H to input API, sulfur distribution, nitrogen distribution and hydrogen content, respectively, for units employing a single character. These are listed below:

Unit	Array
Shale Oil Kerosene Hydrotreater	
Low Severity - Light Kerosene	SSKYL1(I)
Medium Severity - Light Kerosene	SSKYL2(I)
High Severity - Light Kerosene	SSKYL3(I)
Low Severity - Heavy Kerosene	SSKYH1(I)
Medium Severity - Heavy Kerosene	SSKYH2(I)
High Severity - Heavy Kerosene	SSKYH3(I)
Coal Oil Kerosene Hydrotreater	
Low Severity - Light Kerosene	COKYL1(I)
Medium Severity - Light Kerosene	COKYL2(I)
High Severity - Light Kerosene	COKYL3(I)
Low Severity - Heavy Kerosene	COKYH1(I)
Medium Severity - Heavy Kerosene	COKYH2(I)
High Severity - Heavy Kerosene	COKYH3(I)
Shale Oil Gas Oil Hydrocracker	
Low Severity	SSGY1(I)
Medium Severity	SSGY2(I)
High Severity	SSGY3(I)
Coal Oil Gas Oil Hydrocracker	
Low Severity	COGY1(I)
Medium Severity	COGY2(I)
High Severity	COGY3(I)

For those processing units, viscosity is expressed as non-array real numbers.

Unit	Variable
Shale Oil Kerosene Hydrotreater	
Light Kerosene	SSKVL1
Heavy Kerosene	SSKVH1
Shale Oil Gas Oil Hydrocracker	
Light Kerosene	SSGVL1
Heavy Kerosene	SSGVH1
Fuel Oil	SSGVG1

For the coal oil viscosities corresponding to the above, replace SS with CO.

Hydrogen content of streams may be input only for certain process units -- generally those units which yield some portion of their product directly into aviation turbine fuel blends. If values are not input, the hydrogen content is calculated from a generalized correlation employing specific gravity and mid-boiling point. For units not listed below, hydrogen content may not be specified and the correlation results may not be overriden by input specification.

List of Units for Which Product Stream Hydrogen Contents May be Specified

Unit	Array Name
Distillate desulfurizer (petroleum)	
Straight run stock	DDHYDD(I)
FCC light cycle oil	DDHYDL(I)
Light coker/visbreaker gas oil	DDHYDC(I)
Gas Oil hydrocracker (petroleum)	
Straight run stock-gasoline mode	GGHYDG(I)
Coker/visbreaker stock-gasoline mode	GGHYDC(I)
Straight run stock-distillate mode	GMHYDG(I)
Coker/visbreaker stock-distillate mode	GMHYDC(I)
Kerosene hydrotreater (petroleum)	HKHYD(I)

Unit	Low Severity	Medium Severity	High Severity
Shale oil light kerosene hydrotreater	SSKHL1(I)	SSKHL2(I)	SSKHL3(I)
Shale oil heavy kerosene hydrotreater	SSKHH1(I)	SSKHH2(I)	SSKHH3(I)

Coal oil light kerosene hydrotreater	COKHL1(I)	COKHL2(I)	COKHL3(I)
Coal oil heavy kerosene hydrotreater	COKHH1(I)	COKHH2(I)	COKHH3(I)
Shale oil gas oil hydrocracker	SSGH1(I)	SSGH2(I)	SSGH3 (I)
Coal oil gas oil hydrocracker	COGH1(I)	COGH2(I)	COGH3 (I)

Input variable specification for gasoline blending component streams are given below (note that butane values are non-array). All these quantities are input in between &UDATA1 and &END.

	Research Octane Number	
	@ 0 ml. TEL	@ 3 ml. TEL
Butanes	C4OCL	C4OCH
Reformer Feed Prep C5/C6	ROCLD(12)	ROCHD(12)
Mid. Dist. Hydrocracker C5's	DHOCL(13)	DHOCH(13)
Gas Oil Hydrocracker-Light Hydrocrackate	GGOCL(15)	GGOCH(15)
Crude Unit Straight Run Gasoline (incl. C5's)	CUOCL(24)	CUOCH(24)
Cracker Gasoline (Full range)		
From vacuum gas oil at low conversion*	CGOCLL(37)	CGOCHL(37)
From vacuum gas oil at high conversion	CGOCLH(37)	CGOCHH(37)
From coker gas oil at low conversion	CCOCLL(37)	CCOCHL(37)
From coker gas oil at high conversion	CCOCLH(37)	CCOCHH(37)
Visbreaker/Coker light gasoline**	COOCLL(31)	COOCHL(31)
Light Alkylate	ALOCL(21)	ALOCH(21)
Heavy Alkylate	ALOCL(22)	ALOCH(22)
Polymer gasoline	POOCL(23)	POOCH(23)
Light platformate-low severity	ROCLLL(18)	ROCHLL(18)
Light platformate-high severity	ROCLHL(18)	ROCHHL(18)
Heavy platformate-high severity	ROCLLH(19)	ROCHLH(19)
Heavy platformate-high severity	ROCLHH(19)	ROCHHH(19)
Desulfurizer Overhead Gasoline	DDOCL(45)	DDOCH(45)

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* Uses the low conversion input variables for a thermal gas oil cracker.

** For 250°F EP light gasoline (below reforming range) produced from vacuum bottoms coking or visbreaking.

3.2.6 Miscellaneous Stream Quality Factors

The following input variables pertain to quality factors which relate the properties of refinery process unit product streams to the properties of their input streams. They are not required as input unless it is desired to replace the data base values contained within the program. All input variables are real numbers (non-arrays). All input items in this section are included between input header cards &UDATA1 and &END.

The following are API gravity differentials between the indicated product stream and the process unit feed.

Quality Variable	Description
DAHKG*	API of gasoline minus kerosene hydrotreater feed (petroleum)
DAHKK*	API of treated kerosene minus kerosene hydrotreater feed (petroleum)
DAVBLG	API of visbreaker light gasoline minus vacuum bottoms feed
DAVBHG	API of visbreaker heavy gasoline minus vacuum bottoms feed
DAVBGO	API of visbreaker gas oil minus vacuum bottoms feed
DAVBPH	API of visbreaker pitch minus vacuum bottoms feed
DACOLG	API of coker light gasoline minus vacuum bottoms feed
DACOHG	API of coker heavy gasoline minus vacuum bottoms feed
DATCG	API of thermal cracker gasoline minus gas oil feed
DATCTF	API of thermal cracker thermal fuel minus gas oil feed
DACCG	API of catalytic cracker gasoline minus gas oil feed
DACCL	API of catalytic cracker light cycle oil minus gas oil feed
DACCS	API of catalytic cracker bottoms product minus gas gas oil feed

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* Light Kerosene: 400 to 525°F boiling range

Quality Variable	Description
DADDD**	API of desulfurized distillate minus distillate desulfurizer feed (petroleum)
DADDG**	API of gasoline product minus distillate desulfurizer feed (petroleum)
DAGDG	API of gasoline product minus gas oil desulfurizer feed (petroleum)
DAGDD	API of distillate product minus gas oil desulfurizer feed (petroleum)
DAGDGO	API of treated gas oil product minus coker gas oil desulfurizer deed.
DAGGO	API of treated gas oil product minus straight run gas oil desulfurizer feed (petroleum)
DADHH	API of heavy hydrocrackate (250 to 400°F) minus distillate hydrocracker feed
DAHYLK	API of light hydrocrackate minus gas oil hydrocracker feed (in gasoline mode)
DAHYHK	API of heavy hydrocrackate minus gas oil hydrocracker feed (in gasoline mode)
DAHYML	API of light hydrocracker minus gas oil hydrocracker feed (in middle distillate mode)
DAHYMH	API of heavy hydrocrackate minus gas oil hydrocracker feed (in middle distillate mode)
DAHYKL	API of light kerosene (400 to 525°F) minus gas oil hydrocracker feed (distillate operation).
DAHYKH	API of heavy kerosene (525 to 650°F) minus gas oil hydrocracker feed (distillate operation).

** Heavy Kerosene: 525 to 650° F boiling range.

SHALE AND COAL OIL PROCESSING

	Shale Oil Kerosene Hydrotreater						Coal Oil Kerosene Hydrotreater					
	Light Kerosene Product Severity			Heavy Kerosene Product Severity			Light Kerosene Product Severity			Heavy Kerosene Product Severity		
	Low	Medium	High	Low	Medium	High	Low	Medium	High	Low	Medium	High
API Product kerosene minus feed	DASKL1	DASKL2	DASKL3	DASKH1	DASKH2	DASKH3	DACKL1	DACKL2	DACKL3	DACKH1	DACKH2	DACKH3
API Product gasoline minus feed	DASKLS	DASKLS	DASKLS	DASKHS	DASKHS	DASKHS	DACKLS	DACKLS	DACKLS	DACKHS	DACKHS	DACKSH
Fractional Change in Paraffin content*		DPNLKS			DPNHKS			DPNLKC			DPNHKC	
Fractional Change in Aromatic content*		DARLKS			DARHKS			DARLKC			DARHKC	
Change in Freezing Point*		DFRLKS			DRFHKS			DFRLKC			DRFHKC	

* These inputs determine the changes in light kerosene (400 to 525°F) and heavy kerosene (525 to 650°F) properties and should be values which are consistent with the hydrotreating option being specified. As an example, an input of 1.05 for DPNLKS would result in a hydrotreated light kerosene paraffin content 1.05 times that of the shale oil light kerosene feed, an input of .8 for DARLKS results in a product aromatics content of 0.8 times that of the feed. The product naphthene content is calculated by the program by difference. An input of -30.0 for DFRLKS would lower the freezing point of the hydrotreated light kerosene product by 30°F below that of the light kerosene feed.

	Shale Oil Gas Oil Hydrocracking		Coal Oil Gas Oil Hydrocracking	
	Light Kerosene Product (400-525°F)	Heavy Kerosene Product (525-650°F)	Light Kerosene Product (400-525°F)	Heavy Kerosene Product (525-650°F)
Paraffin Content (WT%)*	PNHLKS	PNHHKS	PNHLKC	PNHHKC
Aromatic Content (WT%)	ARHLKS	ARHHKS	ARHLKC	ARHHKC
Naphthene Content (WT%)	NAHLKS	NAHHKS	NAHLKC	NAHHKC
Freezing Point (°F)*	FRHLKS	FRHHKS	FRHLKC	FRHHKC
API Difference Between Product and Gas Oil Feed				
Gas Oil				
- Low Severity	DASHG1		DACHG1	
- Medium Severity	DASHG2		DACHG2	
- High Severity	DASHG3		DACHG3	
Kerosene				
- Low severity	DASHL1	DASHH1	DACHL1	DACHH1
- Medium severity	DASHL2	DASHH2	DACHL2	DACHH2
- High severity	DASHL3	DASHH3	DACHL3	DACHH3
Light Gasoline (250°F EP)*	DASHLG		DACHLG	
Heavy Gasoline (250-400°F)	DASHHG		DACHHG	

* Make these inputs consistent with the specified severity.

	Kerosene Hydrotreater (400 to 525°F)	Distillate Hydrotreater (525 to 650°F)
Fractional Change in Paraffin Content	DPNLKP	DPNHKP
Fractional Change in Aromatic Content	DARLKP	DARHKP
Change in Freezing Point (°F)	DFRLKP	DFRHKP
API difference, gasoline product minus feed	DAHKG	DADDG
API difference treated kerosene or distillate minus feed	DAHKK	DADDD

	Petroleum Gas Oil Hydrocracker	
	Gasoline Mode Operation	Distillate Mode Operation
Light Hydrocrackate Product (IBP to 250°F)*	DAHYLK	DAHYML
Heavy Hydrocrackate Product (250 to 400°F)*	DAHYHK	DAHYMH
Light Kerosene Product (400 to 525°F)**		
API kerosene product minus gas oil feed	-	DAHYKL
Paraffin content, wt%	-	PNHLKP
Napthene content, wt%	-	NAHLKP
Aromatics content, wt%	-	ARHLKP
Freezing Point, °F	-	FRHLKP
Heavy kerosene product (525 to 650°F)**		
API kerosene product minus gas oil feed	-	DAHYKH
Paraffin content, wt%	-	PNHHKP
Napthene content, wt%	-	NAHHKP
Aromatics content, wt%	-	ARHHKP
Freezing Point, °F	-	FRHHKP

* API gravity of gasoline range products minus the gas oil feed

** Kerosene products are not yielded in gasoline mode operation.

3.2.7 Purchased Blending Stocks and Fixed Product Sales

The following input variables relate to the use of segregated refinery blending stocks. Values must be input if any of these segregated feed stocks are used since of course no default values are contained within the program. These streams are used directly for blending and are not "processed" in the refinery. All input in this section must be included between the &PDATA and &END header cards.

Variable	Description
PKERO (1)	Volume (BPD) of segregated kerosene stock (400 to 525°F).
PKERO (2)	API of segregated kerosene stock.
PKERO (3)	Sulfur content of segregated kerosene stock, wt percent.
PKERO (4)	Viscosity of segregated kerosene stock, viscosity blending index at 210°F.
PKERO (5)	Nitrogen content of segregated kerosene stock, wt percent.
PKERO (6)	Hydrogen content of segregated kerosene stock, wt percent.
PKERO (7)	Paraffin content of segregated kerosene stock, wt percent.
PKERO (8)	Naphthene content of segregated kerosene stock, wt. percent
PKERO (9)	Aromatics content of segregated kerosene stock, wt percent.
PKERO (10)	Freezing point of segregated kerosene stock, °F.
PKERO (11)	Smoke point of segregated kerosene stock, millimeters.
PKERO (12)	Heat of combustion of segregated kerosene stock, BTU per pound.

The input logic is identical for purchased heavy kerosene or diesel cut (500 to 650°F), purchased gas oil (650 to 1050°F) and purchased residuum (1050°F +). The corresponding array names are, respectively:

PDSL (I)
PGOIL (I)
PRSD (I)

There is provision in the program for fixed product sales of light and heavy kerosene (diesel) and gas oil. The symbolic variable names are given below.

Name	Type	Units	Description
KERO	Real	BPD	The external sale of the refinery light kerosene stream. If there is a kerosene hydrotreater, it is assumed that the hydrotreated kerosene stream is being sold. Boiling range is 400 to 525°F.
DIESEL	Real	BPD	The external sale of the refinery diesel oil (heavy kerosene) stream. If there is a middle distillate desulfurizer, it is assumed that the desulfurized diesel stream is sold. Boiling range is 525 to 650°F.
GASOIL	Real	BPD	The external sale of the refinery vacuum gas oil stream (untreated). Boiling range is 650 to 1050°F.

3.2.8 Aviation Turbine Fuel and Fuel Oil Blend Specifications

The following input variables relate to the establishment of aviation-turbine fuel blend specifications. If the hydrogen content specification is omitted, the program will bypass blend calculations for determining the maximum quantity of fuel available of a fixed hydrogen content. If the endpoint specification is omitted, a default value of 588°F will be assumed midway between the 525 and 650°F distillation temperature for which blend component yields and properties are contained in the program data bases. All of the variables listed below are real numbers. All information in this section must be included between the &PDATA and &END header cards.

Blend Variable	Description
HDSPEC	The aviation turbine fuel hydrogen content in weight percent.
EPSPEC	The ASTM D-86 endpoint in °F specified for the jet fuel blend (this blend is calculated in addition to the 525 and 650°F endpoint blends, which are calculated as a matter of course).

The following variables relate to the establishment of middle distillate and residual fuel oil blend specifications. If they are not input, as will usually be the case if aviation turbine fuel blending is the prime concern, the program will simply calculate and report the volumes and properties of the remaining total middle distillate and residual fuel oil pools. The following variables must be input if additional fuel oil pool calculations are desired to meet any particular specifications. All of the variables are real numbers.

Blend Variable	Description
SPECMD	The program will calculate and report the maximum volume of middle distillate range fuel oil of the specified <u>sulfur content</u> available from the entire middle distillate fuel oil pool.

SPECRF	The program will calculate and report the maximum volume of residual fuel oil of the specified sulfur content available from the entire residual fuel oil pool.
SPM1, VM1 SPM2, VM2	These input variables refer to the sulfur contents (SPM1, SPM2) and BPD volumes (VM1, VM2) of fixed middle distillate range fuel oil requirements. Either one or two fixed blends may be specified. The program will calculate the composition and properties of these blends and will blend the excess middle distillate components into the residual fuel oil pool.
SPR1, VR1 SPR2, VR2	These are input variables corresponding to the above, but which refer to the residual fuel oil pool. The program will calculate the composition and properties of these residual fuel oil blends, along with the composition, volume, and properties of the remaining residual fuel oil pool after the specified fixed blends have been subtracted out.

3.2.9 Report Options and Economic Data

The following report options are available for specifying the type and quantity of output reports:

IREP	Integer	IREP=1, Summary reports and fuel blending reports only. This option excludes the refinery economic summary report. This is the default option; IREP=2, the above reports, plus the refinery economic summary report; IREP=3, all reports, including material and sulfur, nitrogen, hydrogen balances for each of the refinery process units.

Economic Inputs

These are required only if report options IREP=2 or 3 are in force. Each of the input items entering into the economic calculation are specified below. Required items are listed first, followed by those which are optional because of the inclusion of corresponding values within the program data base. Economics related data base values are given in Exhibit 7. All information in this section must be included between the &PDATA and &END header cards.

Required Inputs

Symbolic Name	Type	Units	Description
STRF	Real Number	Fraction	Average refinery stream day factor. Fraction of time that the refinery is not down for maintenance or emergency repair.
PDBBL (1)	Real Array	dollars per barrel fuel oil equivalent (FOE)	Refinery netback price for fuel gas
PDBBL (2)	"	dollars per liquid barrel @ 60°F	Refinery netback price for LPG sales.

Symbolic Name	Type	Units	Description
PDBBL (3)	Real Array	dollars per liquid barrel @ 60°F.	Refinery netback price for naptha export.
PDBBL (4)	"	"	Refinery netback price for refinery kerosene sale (if any).
PDBBL (5)	"	"	Refinery netback price for refinery diesel sale (if any).
PDBBL (6)	"	"	Refinery netback price for refinery gas oil sale (if any).
PDBBL (7)	"	"	Refinery netback price for the total gasoline pool produced.
PDBBL (8)	"	"	Refinery netback price for the specified aviation turbine fuel blend.
PDBBL (9)	"	"	Refinery netback price for middle distillate fuel oil.
PDBBL (10)	"	"	Refinery netback for residual fuel oil.
DPBBL (I)	"	dollar per liquid barrel @ 60°F	Crude oil cost, where index I refers to the crude oil to be given in Exhibit 4, List of Data Base Crude Oils. If crudes outside of the data base are specified, the codes should correspond to those used for the newly specified crude oils.
PFPR	real number	dollars per barrel of fuel oil equivalent (FOE)	The price assigned to fuel required to meet the internal refinery fuel needs. If these are to be diverted from potential refinery fuel oil or gas sales, then the refinery netback price for these may be used. If outside fuel purchases are required, then the purchase price may apply.
CENTKW	Real number	cents per kilowatt hour.	The refinery power purchase cost.
UNTMP (I)	"	Percent	The percentage of investment cost to be taken for fixed annual maintenance costs for the specified process unit. The index I refers to the process unit identifier given in Exhibit 5 and is used to specify the unit.

UNTVC (I)*	"	dollars per barrel of feed	Process unit variable operating costs.
UNTLC (I)*	"	dollars per day.	Process unit fixed labor costs
IVESTC	Real number	Fraction	The annualized refinery investment carrying charge, expressed on a fraction rather than a percentage. This carrying charge usually includes the cost of capital, local taxes, and plant depreciation.

Optional Inputs (Values are contained in the program data base)

Symbolic Name	Type	Units	Description
UNTCPC (I)*	Real array	dollars per barrel per day ($ per BPD of feed)	Process unit capacity cost corresponding to the unit size, input below.
UNTSTR (I)*	"	BPD	The unit size for which the process unit cost is given.
UNTEXP (I)	"	dimensionless fraction	The power law exponent to be used in adjusting the process unit cost for actual plant size. The equation is: $\left(\frac{I_1}{I_2}\right) = \left(\frac{C_1}{C_2}\right)^N$ I is investment cost C is BPD capacity and N is the power law exponent

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* Exceptions are the alkylation unit, which is based on $/BPD of alkylate product, the polymerization unit which is based on $/BPD of polymer product and the hydrogen plant which is based on dollars per thousands of standard cubic feet per day (60° and 14.696 psia). Note also that the index I refers to the process unit identifier given in Exhibit 5.

3.3 INPUT VARIABLE DEFAULT VALUES

Input variables are given default values within the program in order to minimize the data input requirements. Please note that a subject case of a case study sequence will use the data input established in the base case, rather than revert to the original default values. For example, if a base case has a fluid catalytic cracker, FCC = 50000.0, and it is desired to study the refinery situation without the cracker, then FCC = 0.0 must be input in the subject case, rather than depending on the default value of FCC = 0.0. In brief, the base case values override the program default values.

3.3.1 Unit Throughputs

All unit throughputs are initialized to 0.0, so that if a unit is not present within a refinery configuration, no input item is required for that unit. The atmospheric crude unit capacity is calculated by the program to accomodate the total quantity of crude oil charged to the refinery. Vacuum distillation capacity, however, must be specified.

3.3.2 Unit Operations

a) CONV = CONVH = 85.0

REFRON = RONHI = 100.0

Fluid catalytic cracker and catalytic Naphtha Reformer severities are initialized at the maximum.

b) MODE = 1

The Gas Oil Hydrocracker is assumed to be in the gasoline production mode unless otherwise specified.

c) SVSKHT, SVCKHT, SVSGHT, SVCGHT all = 2.

The Shale Oil and Coal Oil Kerosene Hydrotreater and Gas Oil Hydrocrackers are all initialized at medium severity.

3.3.3 Internal Stream Destinations

The default option is to prorate the volume of internal refinery streams having more than one downstream destination by the capacity of the alternative downstream process units. For example, if:

GODES	= 50000.0	Gas Oil Desulfurization Capacity
FCC	= 50000.0	Fluid Catalytic Cracker

then:

VGODES	= 0.5	Fraction virgin gas oil to desulfurization
CGODES	= 0.5	Fraction coker gas oil to desulfurization
VGOFCC	= 0.5	Fraction virgin gas oil to cracker
CGOFCC	= 0.5	Fraction coker gas oil to cracker

In the above, any gas oils which can not be accomodated by the process units because of restrictive capacity will automatically go to residual fuel oil blending. If the fractional disposition of a given internal refinery is less than 1.0, then the remainder will automatically be sent to final product blending, regardless of process unit capacities. For example, if the only destination for light cycle oil is desulfurization, but it is desired to send 20% directly to middle distillate fuel oil blending, then input LCODES = 0.8 and the program automatically sends the remainder to fuel oil blending.

3.3.4 Product Sales

KERO = 0.0

DIESEL = 0.0

GASOIL = 0.0

It is assumed that unless otherwise specified there are no external kerosene, diesel or gasoil sales.

3.3.5 Segregated Blending Stocks

PKERO (1) = 0.0

PDSL (1) = 0.0

PGOIL (1) = 0.0

PRSD (1) = 0.0

The volumes of purchased segregated fuel oil blending stocks (which remain unmixed with any other refinery streams prior to blending) are initialized at zero. The actual volumes and stream properties must be supplied by the program user if segregated blending stocks are desired.

3.3.6 Blend Specifications

The following blend specification values are present for aviation turbine fuel:

EPSPEC = 588.0°F

HDSPEC = 0.0

The endpoint specification default is set midway between 525 and 650°F, the ASTM temperature corresponding to blending component properties contained within the program data base. The effect of the hydrogen specification default of 0.0 is to bypass program options that blend aviation turbine fuels to a minimum hydrogen content blend specification.

The following blend specifications values are present for middle distillate and residual fuel oil blends:

SPECMD = 0.0

SPM1 = 0.0   VM1 = 0.0

SPM2 = 0.0   VM2 = 0.0

SPECRF = 0.0

SPR1 = 0.0   VR1 = 0.0

SPR2 = 0.0   VR2 = 0.0

The effect of the above zero initialization values is to make the programmed assumption that no fixed volume and sulfur content blends are to be produced, unless explicitly specified by the program user by using one or more of the above input variables. If none of the above input variables are specified, the program will simply calculate the volume and properties of the distillate and residual fuel oil pools, after jet fuel production.

3.3.7 Data Base Values

Yields, stream properties, and stream quality factors are contained within the program to approximate a typical petroleum refinery with a wide range of individual process units. In addition, crude assay data is contained within the program for a number of crude oils of world-wide importance. The full list of stored data is not presented here. The complete data base is contained in the programming documentation found in Volume III (NASA CR-135335).

Any item in the process unit and crude assay data base may be altered by the user to represent variations in process unit yields, stream qualities, and crude oil assays. This affords the model user considerable power in matching a particular petroleum refining situation.

Crude oil and process unit data base items must be changed at the beginning of the input data stream run set up and remains in force for all subsequent base and subject cases throughout the run sequence.

Separate job steps are required if it is desired to study the effect of varying the crude assay or process unit data base values. The crude oil and process unit data base files are handled by the program as permanent files throughout a run sequence once the initial changes are made at the beginning of the input card stream.

Process unit investment costs, fixed and variable operating cost information, and investment cost power law exponents are contained in the program data base (in subroutine Block Data). These values are used in the economic calculation, unless altered by the user during run sequence.

4.0 MODEL FLEXIBILITY AND LIMITATIONS

The Gordian Refinery Simulation Model was developed using the Control Data 6600 computer and has been converted to the IBM 360/67 computer. Their program requires about 225 K words of storage on the CDC 6600 computer and about 400 K bytes of storage on the IBM 360/67 computer.

The detailed model limitations are covered either explicitly or implicitly in section 3.0 (the input description) of this manual. In general, any capability not encompassed by the description of program inputs is not available to the model. The purpose of this section is to summarize the principal model limitations and flexibility aspects.

(1) The total crude data base is limited to 35 distinct crude types. The program is presently organized that 26 of these are reserved for permanent data base crudes and 9 are for crudes which the user may want to add during a particular run sequence. Petroleum based, coal based and shale oil based crude oils may be specified for refinery processing.

The word crude is used somewhat loosely. Gas oils, diesel stocks and kerosenes may also be made a part of either the permanent or temporary data base. The capability reserved for additional crude types may also be used to represent refinery purchase streams such as natural gas and butanes.

(2) An important factor in using the above refinery feed capabilites is to recognize that petroleum, coal based and shale oil based crude oils are processed through segregated crude units and hydrotreating facilities. In order to simulate the situation where segregated blending stocks are used, as many as four purchased blending stocks may be specified.

The input terminology suggests that the purchased streams are the kerosene, diesel, gas oil, and residuum types. Actually, since all of the stream properties must be supplied along with the volume rate of the feed, these streams may represent any segregated stream in general. Thus, it would be possible to specify two segregated gas oil and two segregated kerosene streams as purchase for final fuel oil blending stocks.

Any streams of the above type are not blended with any other feeds prior to being blended into their respective fuel oil pools.

(3) The refinery process units which are included in the model's process unit data base are restricted to those specified in Exhibit 5. Programming modifications are necessary to expand the allowable petroleum refinery configuration beyond its present range.

The model is flexible in allowing for diversity in the specification of the refinery configuration. For example, units using the same feed stream type such as a fluid cracker and a thermal cracker (using straight run virgin gas oil) may be included within the same refinery configuration. When dual units of this type are included, it is necessary to define the split in the feed stream between units by making use of the appropriate input variables, unless the default of prorating feeds by available capacity is desired.

(4) Aviation Turbine fuel (jet fuel blends) in the kerosene range are reported by the model. Considerable flexibility has been included in the program in order to extract the maximum useful information from a single run. The user may specify a jet fuel endpoint specification and minimum hydrogen content specification. The model will then calculate blends as 525°F, 650°F and the specified endpoint. All blends are reported on an "as made" basis and at the specified hydrogen content.

The aviation turbine fuel of specified endpoint and specified hydrogen content is calculated as the basis for the overall refinery balance, with the remaining distillate components going to distillate fuel (heating oil) blending.

(5) Up to two fixed distillate blends and two fixed residual fuel oil blends may be specified. Both sulfur content and blend volume must be specified for each fixed blend.

Each distillate blend specified is subtracted from the total distillate fuel oil pool and the volume, composition, and properties of the remaining pool are calculated by the model. Any excess middle distillate components are then blended into the residual fuel oil pool. The required residual fuel oil blends are then made and the properties of the remaining residual pool are reported.

5.0 SAMPLE PROBLEM SET-UPS

The copies of computer card input shown in Exhibit 8 illustrate the feature of the Gordian Refinery Simulation Model of handling a base case and subsequent dependent cases. The first group of images is the sample case presented in Exhibit 1. Two dependent input setups are shown for changes in jet fuel, distillate, and residual fuel outputs. Each input group represents a change only in the variables shown; all others remain at base case values. The third case has an input variable to indicate that it is the last of the dependent series and the subsequent run will be a new base case.

6.0 DIAGNOSTICS

Input editing for system errors is accomplished by the FORTRAN Namelist feature. Such errors as mispunched header cards, mispunching or misspelling of input variable names, omission of commas and errors in numeric field punching are flagged by Namelist and generally result in problem termination. An additional diagnostic has been included in the program to signal a premature end-of-file in the input stream, i.e. before an &END trailer card has been reached.

The program has been written to provide automatically for such contingencies as undersized process units, and deficiencies in hydrogen or fuel availability by blending off excess feed streams and by indicating the need for purchase. The greatest propensity of the program to fail in the calculation is probably in the jet fuel, distillate and residual fuel oil blending calculations. The problem arises in trying to make specified fuels outside of the ability of the program to do so -- for example, if a hydrogen specification content of 15.0 weight percent were specified for a 650°F endpoint jet fuel blend and the highest blending component hydrogen content were 14.8 weight percent.

The subroutine involved in making the blending calculation is BMAX. Either or both of two messages are issued by BMAX if a blending problem develops:

"A FUEL OIL BLEND CALCULATION HAS FAILED -- CHECK INPUT"

"A ZERO DIVIDE HAS OCCURED IN SUBROUTINE BMAX -- THE RESULTS ARE THEREFORE SUSPECT -- CHECK PROBLEM INPUT"

The input checks under this circumstance would usually consist of redefining a feasible problem, i.e., a refinery configuration capable of making the specified blends.

7.0 CONCLUDING REMARKS

This report has described the Gordian Refinery Simulation Model, a Fortran computing program for predicting the flow streams and material, energy, and economic balances of a typical petroleum refinery, with particular emphasis on production of aviation turbine fuel of varying end point and hydrogen content specifications. Program logic, optional and required input, default values, diagnostics, and sample output are discussed. A brief example is included, illustrating the case feature for parametric or optimization study variations of a base case.

It is felt that the material presented in this report will be sufficient for the needs of many readers. The simplicity and flexibility of the program can be readily assessed, and the limitations should be apparent, particularly with respect to uncertain reliability when dealing with the properties of shale and coal syncrudes. The sample input and output printouts presented here can serve as a guide for interpretation of future reported listings and data. Additional details, however, will be found in Volume II of this report series (NASA CR-135334) covering the mathematics and data bases and Volume III covering the program listing, both documents to be available from the NASA Project Manager. Computer documentation and tapes can be purchased through the Computer Software and Management Information Office (COSMIC), 112 Barrow Hall, University of Georgia, Athens, GA, 30602, under the number LEW-13047.

8.0 REFERENCES

1. Kalfadelis, Charles D.: Evaluation of Methods to Produce Aviation Turbine Fuels from Synthetic Crude Oils - Phase II. AFAPL-TR-75-10-Volume II, 1976.

2. Antoine, A.C.; and Gallagher, J.P.: Jet Fuels from Synthetic Crudes. C.E.P. Technical Manual, Coal Processing Technology, Vol. 3 AIChE New York, 1977, pp. 23-27.

3. Bonner and Moore, Associates: U.S. Motor Gasoline Economics, Vol. 1, Manufacture of Unleaded Gasoline. Amer. Petroleum Inst., Washington, 1967.

4. Technical Data Book - Petroleum Refining. Third ed. Amer. Petroleum Inst., Washington, 1976.

5. Nelson, W.L.: Petroleum Refinery Engineering. Fourth ed. McGraw-Hill Book Co., 1969.

6. Reid, Eugene B.; and Allen, Howard I.: Estimating Pour Points of Petroleum Distillate Blends. Petroleum Refiner, Vol. 30, no. 5, May 1951, pp. 93-95.

LISTS OF EXHIBITS

EXHIBIT 1

COMPUTER PRINTOUT FOR A SAMPLE CASE

On the following pages, a printout of a sample case using the Gordian Refinery Simulation Model is reproduced. On the first page, the optional input data are illustrated. A crude assay data change input is shown between &CDATA and &END, an alkylation unit feed nitrogen content change between &UDATA and &END, and an alkylation unit product octane number change between &UDATA1 and &END. (The printing unit lacks a & symbol and substitutes a $ on the printout). On the second page, required data between &PDATA and &END are shown. The selected case represents a refinery model with crude feed of 33,000 BPD each of Agha Jari petroleum, Paraho shale, and Kentucky synthoil coal oil. The input variables prescribe the sizes of the process units, catalytic cracker conversion, mid-distillate operation, and medium hydrotreater and hydrocracker severity. These input values are summarized on a page titled, "SUMMARY OF REFINERY UNIT OPERATIONS" near the end of the printout pages. The input IREP=3 specifies a complete printout, including all material balances and economic calculations. The production of jet fuel pools with a specified 600°F end point and 12.8% hydrogen is indicated. This sample case is discussed briefly in Section 2.2 of this report.

1...INPUT CARD IMAGES

```
$PDATA
ICASE=1,IREP=3,
CV(9)=33000.0,CV(11)=33000.0,CV(14)=33000.0,ALKY=2000.0,BI=1000.0,FCC=30000.0,
CONV=7000,VACD=20000.0,GOHYC=5000.0,MODE=2,HTKERO=1000.0,HYD= 50.0,POLY=500.0,
REF=20000.0,REFRON=95.0,TCC=10000.0,COKER=5000.0,VACS=20000.0,VACC=20000.0,
SOKHT=2000.0,COKHT=2000.0,CGOHYC=10000.0,SGOHYC=5000.0,DIESEL=500.0,KERO=500.0,
DPBBL=70*10.00,IVESTCC=0.15,CENTKWH=2.5,STRF=0.92,PFPR=9.00,
PDBBL=9.00,10.50,15.00,14.75,13.75,13.00,16.80,15.00,14.70,12.30,8.00,9*0.0,
GODES=1000.0,MDDES=1000.0,MDHYC=1000.0,EPSPEC=600.0,HDSPEC=12.8,
$END
```

CRUDE UNIT(PETROLEUM) MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
CRUDE OIL MIX	852.62	34.300	1.3400	.13	13.00	51.72	410468.	.693	5500.3	.0672	533.6	6.72	53361.
TOTAL INPUT						51.72	410468.	.69	5500.	.07	534.	6.72	53361.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	0.0000	0.00	22.22	.06	437.	0.000	0.0	0.0000	0.0	.01	97.
PROPANE	507.21	147.208	0.0000	0.00	18.18	.19	1514.	0.000	0.0	0.0000	0.0	.03	275.
ISO BUTAE	562.56	119.788	0.0000	0.00	17.24	.12	948.	0.000	0.0	0.0000	0.0	.02	163.
N-BUTANE	583.64	110.629	0.0000	0.00	17.24	.48	3794.	0.000	0.0	0.0000	0.0	.08	654.
PENTANES	630.59	92.676	0.0000	0.00	16.67	1.05	8348.	0.000	0.0	0.0000	0.0	.18	1391.
LIGHT GASOLINE	719.41	65.000	.0200	.00	14.90	4.72	37474.	.001	7.5	.0000	.2	.70	5584.
HEAVY NAPTHA	774.60	51.000	.0400	.00	14.30	7.28	57801.	.003	23.1	.0001	.6	1.04	8265.
LIGHT KEROSENE	819.50	41.000	.4000	.00	13.60	6.46	51288.	.026	205.2	.0003	2.1	.88	6975.
HEAVY KEROSENE	854.16	34.000	.9500	.01	13.10	6.48	51402.	.062	488.3	.0006	5.1	.85	6734.
VACUUM GAS OIL	914.98	23.000	1.7700	.11	12.20	11.54	91575.	.204	1620.9	.0121	96.2	1.41	11172.
VACUUM BOTTOMS	1022.16	6.800	3.6700	.58	10.80	5.90	46816.	.216	1718.1	.0342	271.5	.64	5056.
REDUCED CRUDE	948.63	17.520	2.4127	.27	11.73	7.31	57986.	.176	1399.0	.0194	154.1	.86	6800.
TOTAL OUTPUT						51.58	409382.	.69	5462.	.07	530.	6.70	53167.
LOSS AND UNACCOUNTED FOR						.14	1086.	.00	38.	.00	4.	.02	194.

CRUDE UNIT(PETROLEUM) ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	3.9	31325.8	2.8	1195.0	11.0	37.4	6.2	.156
FUEL	1.4	10854.0	48.8	21000.0	66.8	227.9	37.7	.949
POWER					.9	3.0	.5	.012
TOTALS					78.6	268.3	44.4	1.117

CRUDE UNIT(COAL) MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
COAL OILMIX	1028.85	5.300	.2200	.79	9.22	62.41	495310.	.137	1089.7	.4930	3913.0	5.75	45668.
TOTAL INPUT						62.41	495310.	.14	1090.	.49	3913.	5.75	45668.
PRODUCT STREAMS													
HEAVY NAPTHA	893.52	26.710	.1030	.30	11.00	.92	7313.	.001	7.3	.0028	21.9	.10	804.
LIGHT KEROSENE	923.35	21.600	.0920	.29	10.80	9.13	72456.	.008	66.7	.0265	210.1	.99	7825.
HEAVY KEROSENE	959.05	15.900	.1400	.32	10.40	14.89	118197.	.021	165.5	.0477	378.2	1.55	12292.
COAL GASOIL	1003.29	9.400	.1200	.47	10.10	16.07	127514.	.019	153.0	.0755	599.3	1.62	12879.
VACUUM BOTTOMS	1111.35	-4.300	.3100	1.22	8.50	20.22	160509.	.063	497.6	.2467	1958.2	1.72	13643.
TOTAL OUTPUT						61.23	485988.	.11	890.	.40	3169.	5.99	47545.
LOSS AND UNACCOUNTED FOR						1.17	9322.	.03	199.	.09	744.	-.24	-1877.

CRUDE UNIT(COAL) ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	3.9	31325.8	2.8	1195.0	11.0	37.4	6.2	.156
FUEL	1.4	10654.0	48.8	21000.0	66.8	227.9	37.7	.949
POWER					.9	3.0	.5	.012
TOTALS					78.6	268.3	44.4	1.117

CRUDE UNIT(SHALE) MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
SHALE OIL MIX	937.43	19.300	.7100	2.00	11.50	56.06	451297.	.404	3204.2	1.1373	9025.9	6.54	51899.
TOTAL INPUT						56.06	451297.	.40	3204.	1.14	9026.	6.54	51899.
PRODUCT STREAMS													
HEAVY NAPTHA	821.55	40.570	.9023	.00	12.50	.75	5933.	.007	53.5	.0000	.1	.09	742.
LIGHT KEROSENE	852.82	34.260	.6587	1.01	12.20	3.88	30793.	.026	202.8	.0392	311.0	.47	3757.
HEAVY KEROSENE	891.27	27.110	.5910	1.90	11.50	8.65	68652.	.060	474.4	.1644	1305.0	.99	7895.
SHALE GAS OIL	946.53	17.850	.6008	2.0.	10.90	30.62	243029.	.184	1460.1	.6115	4853.5	3.34	26490.
VACUUM BOTTOMS	1033.36	5.300	.4000	3.06	9.40	4.56	36181.	.018	144.7	.1395	1107.1	.43	3401.
REDUCED CRUDE	956.95	16.224	.5748	2.13	10.71	8.36	66312.	.048	381.1	.1784	1415.7	.89	7099.
TOTAL OUTPUT						56.81	450899.	.34	2717.	1.13	8992.	6.23	49475.
LOSS AND UNACCOUNTED FOR						.05	399.	.06	487.	.00	34.	.31	2424.

CRUDE UNIT(SHALE) ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	3.9	31325.8	2.8	1195.0	11.0	37.4	6.2	.156
FUEL	1.4	10854.0	48.8	21000.0	66.8	227.9	37.7	.949
POWER					.9	3.0	.5	.012
TOTALS					78.6	268.3	44.4	1.117

KEROSENEHYDRO TREATER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.00	22.	0.000	0.0	0.0000	0.0	.00	22.
LIGHT KEROSENE	819.50	41.000	.4000	.00	13.60	1.51	11955.	.006	47.8	.0001	.5	.20	1626.
TOTAL INPUT						1.51	11977.	.01	48.	.00	0.	.21	1648.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	48.2532	.46	11.39	.01	84.	.005	40.6	.0001	.4	.00	10.
GASOLINE	734.36	61.000	.9300	.01	14.88	.03	257.	.000	2.4	.0000	.0	.00	38.
HYDRO TRT LT KER	817.13	41.500	.0409	.00	13.73	1.47	11682.	.001	4.8	.0000	.0	.20	1604.
TOTAL OUTPUT						1.51	12024.	.01	48.	.00	0.	.21	1651.
LOSS AND UNACCOUNTED FOR						-.01	-46.	.00	0.	.00	0.	-.00	-3.

KEROSENEHYDRO TREATER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.0	295.3	2.8	1195.0	.1	.4	.1	.001
FUEL	.0	208.9	48.8	21000.0	1.3	4.4	.7	.018
POWER					.1	.2	.0	.001
HYDROGEN	.0	22.0	120.2	51667.0	.3	1.1	.2	.005
TOTALS					1.8	6.1	1.0	.025

FLUID COKER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
VACUUM BOTTOMS	1081.69	-.740	.9694	1.37	9.08	9.94	78858.	.096	764.4	.1362	1080.6	.90	7157.
TOTAL INPUT						9.94	78858.	.10	764.	.14	1081.	.90	7157.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	6.9872	9.88	18.47	.45	3610.	.032	252.3	.0449	356.6	.08	667.
PROPANE	507.21	147.208	.2672	.38	18.06	.11	858.	.000	2.3	.0004	3.2	.02	155.
PROPYLENE	521.50	139.573	.7045	.45	14.18	.09	753.	.000	2.3	.0004	3.2	.01	107.
ISO BUTAE	562.56	119.788	.4202	.59	17.07	.07	546.	.000	2.3	.0004	3.2	.01	93.
N-BUTANE	583.84	110.629	1.4958	2.11	16.62	.02	153.	.000	2.3	.0004	3.2	.00	25.
BUTYLENE	604.42	102.384	.2874	.41	14.19	.10	798.	.000	2.3	.0004	3.2	.01	113.
LIGHT GASOLINE	741.06	59.260	.1820	.26	14.65	.69	5460.	.001	9.9	.0018	14.0	.10	800.
HEAVY GASOLINE	804.30	44.260	.4179	.59	13.44	.78	6219.	.003	26.0	.0045	36.7	.11	836.
COKER GAS OIL	931.50	20.260	.6103	.86	11.64	4.13	32818.	.025	200.3	.0357	283.1	.48	3820.
COKE	1075.01	0.000	1.2133	1.72	2.00	2.75	21799.	.033	264.5	.0471	373.9	.05	436.
TOTAL OUTPUT						9.20	73014.	.10	764.	.14	1081.	.89	7053.
LOSS AND UNACCOUNTED FOR						.74	5844.	.00	0.	.00	0.	.01	104.

FLUID COKER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	-.5	-4219.0	2.8	1195.0	-1.5	-5.0	-.8	-.021
FUEL	.2	1980.7	48.8	21000.0	12.2	41.6	6.9	.173
POWER					1.2	4.3	.7	.018
TOTALS					12.0	40.8	6.7	.170

CATALYTIC CRACKER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
VACUUM GAS OIL	914.98	23.000	1.7700	.11	12.20	7.52	59723.	.133	1057.1	.0079	62.7	.92	7286.
COKER GAS OIL	931.50	20.260	.6103	.86	11.64	3.45	27348.	.021	166.9	.0297	235.9	.40	3184.
TOTAL INPUT						10.97	87071.	.15	1224.	.04	299.	1.32	10470.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	15.0194	3.66	18.07	.31	2445.	.046	367.2	.0113	89.6	.06	442.
PROPANE	507.21	147.208	1.0100	.25	17.95	.15	1212.	.002	12.2	.0004	3.0	.03	218.
PROPYLENE	521.50	139.573	.2460	.03	14.24	.63	4976.	.002	12.2	.0004	3.0	.09	709.
ISO BUTAE	562.56	119.788	.6214	.15	17.11	.25	1970.	.002	12.2	.0004	3.0	.04	337.
N-BUTANE	583.84	110.629	1.8408	.45	16.85	.08	655.	.002	12.2	.0004	3.0	.01	112.
BUTYLENE	604.42	102.384	.4468	.11	14.21	.35	2740.	.002	12.2	.0004	3.0	.05	389.
TOTAL GASOLINE	791.16	47.179	.1158	.03	13.39	5.33	42288.	.006	49.0	.0015	11.9	.71	5663.
LIGHT CYCLE OIL	897.83	25.950	1.5570	.38	11.49	2.56	20309.	.040	318.2	.0098	77.6	.29	2333.
BOTTOMS	1144.76	-8.312	2.3316	.57	8.15	1.26	9974.	.029	232.6	.0071	56.7	.10	813.
TOTAL OUTPUT						10.91	86578.	.13	1028.	.03	251.	1.39	11015.
LOSS AND UNACCOUNTED FOR						.06	493.	.02	196.	.01	48.	-.07	-545.

CATALYTIC CRACKER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	-.7	-5801.9	2.8	1195.0	-2.0	-6.9	-1.1	-.029
FUEL	.2	1946.7	48.8	21000.0	12.0	40.9	6.8	.170
POWER					.3	1.1	.2	.005
TOTALS					10.3	35.1	5.8	.146

THERMAL CRACKER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
VACUUM GAS OIL	914.98	23.000	1.7700	.11	12.20	2.51	19908.	.044	352.4	.0026	20.9	.31	2429.
TOTAL INPUT						2.51	19908.	.04	352.	.00	21.	.31	2429.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	14.6201	.87	18.78	.11	844.	.016	123.3	.0009	7.3	.02	158.
PROPANE	507.21	147.208	.6140	.04	18.06	.07	574.	.000	3.5	.0000	.2	.01	104.
PROPYLENE	521.50	139.573	1.6345	.10	14.04	.03	216.	.000	3.5	.0000	.2	.00	30.
ISO BUTAE	562.56	119.788	2.3999	0.00	16.83	.02	147.	.000	3.5	0.0000	0.0	.00	25.
N-BUTANE	583.84	110.629	.6159	.05	17.09	.05	432.	.000	3.5	.0000	.2	.01	74.
BUTYLENE	604.42	102.384	.8932	.05	14.15	.05	395.	.000	3.5	.0000	.2	.01	56.
TOTAL GASOLINE	787.54	48.000	.2587	.02	13.39	.69	5449.	.002	14.1	.0001	.8	.09	730.
HEAVY FUEL	914.98	23.000	1.7732	.11	12.81	1.40	11128.	.025	197.3	.0015	11.7	.18	1425.
TOTAL OUTPUT						2.42	19183.	.04	352.	.00	21.	.33	2602.
LOSS AND UNACCOUNTED FOR						.09	724.	.00	0.	.00	0.	-.02	-173.

THERMAL CRACKER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.3	5977.6	2.8	1195.0	2.1	7.1	1.2	.030
FUEL	.2	1969.3	48.8	21000.0	12.1	41.4	6.8	.172
POWER					.1	.4	.1	.002
TOTALS					14.3	48.9	8.1	.204

GAS OIL HYDRO CRACKER — MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.08	667.	0.000	0.0	0.0000	0.0	.08	667.
VACUUM GAS OIL	914.98	23.000	1.7700	.11	12.20	1.25	9954.	.022	176.2	.0013	10.5	.15	1214.
COKER GAS OIL	931.50	20.260	.6193	.86	11.64	.57	4558.	.004	27.8	.0050	39.3	.07	531.
TOTAL INPUT						1.91	15178.	.03	204.	.01	50.	.30	2412.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	63.3585	15.46	4.71	.04	319.	.025	202.0	.0062	49.3	.00	15.
PROPANE	507.21	147.208	0.0000	0.00	18.18	.02	194.	0.000	0.0	0.0000	0.0	.00	35.
ISO BUTAE	562.56	119.738	0.0000	0.00	17.24	.01	88.	0.000	0.0	0.0000	0.0	.00	15.
N-BUTANE	583.84	110.629	0.0000	0.00	17.24	.02	176.	0.000	0.0	0.0000	0.0	.00	30.
LIGHT GASOLINE	707.71	68.248	.0834	.02	16.30	.06	489.	.000	.4	.0000	.1	.01	80.
HEAVY GASOLINE	749.67	57.069	.0130	.00	15.59	.40	3145.	.000	.4	.0000	.1	.06	490.
HYDRO TRT LT KER	814.12	42.141	.0116	.00	13.82	.66	5264.	.000	.6	.0000	.1	.09	728.
DESUL HYKER	853.44	34.140	.0111	.00	13.66	.70	5519.	.000	.6	.0000	.1	.09	754.
TOTAL OUTPUT						1.91	15195.	.03	204.	.01	50.	.27	2147.
LOSS AND UNACCOUNTED FOR						-.00	-16.	.00	0.	.00	0.	.03	264.

GAS OIL HYDRO CRACKER — ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.0	114.0	2.8	1195.0	.0	.1	.0	.001
FUEL	.0	172.6	48.8	21000.0	1.1	3.6	.6	.015
POWER					.4	1.5	.2	.006
HYDROGEN	.1	666.6	120.2	51667.0	10.1	34.4	5.7	.143
TOTALS					11.6	39.7	6.6	.165

GAS OIL DESULFURIZER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.00	29.	0.000	0.0	0.0000	0.0	.00	29.
VACUUM GAS OIL	914.98	23.000	1.7700	.11	12.20	.25	1991.	.004	35.2	.0003	2.1	.03	243.
COKER GAS OIL	931.50	20.260	.6103	.86	11.64	.11	912.	.001	5.6	.0010	7.9	.01	106.
TOTAL INPUT						.37	2932.	.01	41.	.00	10.	.05	378.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	44.4256	10.84	9.94	.01	78.	.004	34.7	.0011	8.5	.00	8.
DISTILLATE	829.12	39.000	1.3952	.08	13.53	.02	126.	.000	1.8	.0000	.1	.00	17.
DISTILLATE	842.65	36.260	.4819	.68	13.12	.01	58.	.000	.3	.0000	.4	.00	8.
DESUL GAS OIL	903.29	25.000	.1928	.01	12.63	.23	1828.	.000	3.5	.0000	.2	.03	231.
DESUL GAS OIL	919.38	22.260	.0665	.09	12.20	.11	837.	.000	.6	.0001	.8	.01	102.
TOTAL OUTPUT						.37	2927.	.01	41.	.00	10.	.05	365.
LOSS AND UNACCOUNTED FOR						.00	5.	.00	0.	.00	0.	.00	13.

GAS OIL DESULFURIZER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.0	63.9	2.8	1195.0	.0	.1	.0	.000
FUEL	.0	38.4	48.8	21000.0	.2	.8	.1	.003
POWER					.0	.0	.0	.000
HYDROGEN	.0	29.4	120.2	51667.0	.4	1.5	.3	.006
TOTALS					.7	2.4	.4	.010

DISTILLATE DESULFURIZER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.01	80.	0.000	0.0	0.0000	0.0	.01	80.
HEAVY KEROSENE	854.16	34.000	.9500	.01	13.10	1.14	9057.	.011	86.0	.0001	.9	.15	1186.
LIGHT CYCLE OIL	897.83	25.950	1.5670	.38	11.49	.45	3578.	.007	56.1	.0017	13.7	.05	411.
TOTAL INPUT						1.60	12715.	.02	142.	.00	15.	.21	1678.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	71.7831	7.37	4.63	.02	186.	.017	133.6	.0017	13.7	.00	9.
GASOLINE	771.52	51.729	.5739	.03	13.83	.03	248.	.000	1.4	.0000	.1	.00	34.
DESUL LTCYCLE	886.57	27.950	.0810	.02	11.96	.44	3463.	.000	2.8	.0001	.7	.05	414.
DESUL HYKER	843.97	36.000	.0491	.03	13.49	1.10	8770.	.001	4.3	.0000	.0	.15	1183.
TOTAL OUTPUT						1.60	12666.	.02	142.	.00	15.	.21	1640.
LOSS AND UNACCOUNTED FOR						.01	49.	.00	0.	.00	0.	.00	37.

DISTILLATE DESULFURIZER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.0	214.6	2.8	1195.0	.1	.3	.0	.001
FUEL	.0	151.8	48.8	21000.0	.9	3.2	.5	.013
POWER					.0	.2	.0	.001
HYDROGEN	.0	35.1	120.2	51667.0	.5	1.8	.3	.008
TOTALS					1.6	5.4	.9	.023

DISTILLATE HYDROCRACKER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.08	621.	0.000	0.0	0.0000	0.0	.08	621.
HEAVY KEROSENE	854.16	34.000	.9500	.01	13.10	1.14	9057.	.011	86.0	.0001	.9	.15	1186.
LIGHT CYCLE OIL	897.83	25.950	1.5670	.38	11.49	.45	3578.	.007	56.1	.0017	13.7	.05	411.
TOTAL INPUT						1.67	13256.	.02	142.	.00	15.	.28	2218.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	38.9696	4.00	12.67	.05	361.	.018	140.7	.0018	14.4	.01	46.
PROPANE	507.21	147.208	0.0000	0.00	18.18	.09	752.	0.000	0.0	0.0000	0.0	.02	137.
ISO BUTAE	562.56	119.788	0.0000	0.00	17.24	.16	1286.	0.000	0.0	0.0000	0.0	.03	222.
N-BUTANE	533.84	110.629	0.0000	0.00	17.24	.08	670.	0.000	0.0	0.0000	0.0	.01	116.
PENTANES	629.40	93.103	.0392	.00	16.66	.23	1813.	.000	.7	.0000	.1	.04	302.
HEAVY GASOLINE	751.01	56.731	.0095	.00	15.52	1.05	8351.	.000	.7	.0000	.1	.16	1296.
TOTAL OUTPUT						1.67	13233.	.02	142.	.00	15.	.27	2118.
LOSS AND UNACCOUNTED FOR						.00	22.	.00	0.	.00	0.	.01	100.

DISTILLATE HYDROCRACKER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
FUEL	.1	504.2	48.8	21000.0	3.1	10.6	1.8	.044
POWER					.6	2.0	.3	.008
HYDROGEN	.1	620.6	120.2	51667.0	9.4	32.1	5.3	.133
TOTALS					13.1	44.7	7.4	.186

SHALE KERO HYDROTREATER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.28	2245.	0.000	0.0	0.0000	0.0	.28	2245.
LIGHT KEROSENE	852.82	34.260	.6537	1.01	12.20	1.00	7941.	.007	52.3	.0101	80.2	.12	969.
HEAVY KEROSENE	891.27	27.110	.6910	1.92	11.50	2.23	17705.	.015	122.3	.0424	336.6	.26	2036.
TOTAL INPUT						3.51	27891.	.02	175.	.05	417.	.66	5250.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	15.9644	38.10	10.21	.14	1083.	.022	172.9	.0520	412.6	.01	111.
HYDRO TRT LT KER	804.30	44.260	.0065	.01	14.13	1.02	8089.	.000	.5	.0001	.8	.14	1143.
HYDRO TRT HY KER	838.41	37.110	.0068	.02	13.70	2.27	17988.	.000	1.2	.0004	3.4	.31	2465.
TOTAL OUTPUT						3.42	27159.	.02	175.	.05	417.	.47	3719.
LOSS AND UNACCOUNTED FOR						.09	732.	.00	0.	.00	0.	.19	1531.

SHALE KERO HYDROTREATER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.8	6328.5	2.8	1195.0	2.2	7.6	1.3	.031
FUEL	.1	720.2	48.8	21000.0	4.4	15.1	2.5	.063
POWER					1.2	4.3	.7	.018
HYDROGEN	.3	2244.3	120.2	51667.0	34.0	116.0	19.2	.483
TOTALS					41.9	142.9	23.6	.595

COAL KERO HYDROTREATER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.28	2206.	0.000	0.0	0.0000	0.0	.28	2206.
LIGHT KEROSENE	923.35	21.600	.0920	.29	10.80	1.32	10480.	.001	9.6	.0038	30.4	.14	1132.
HEAVY KEROSENE	959.05	15.900	.1400	.32	10.40	2.15	17097.	.003	23.9	.0069	54.7	.22	1778.
TOTAL INPUT						3.75	29783.	.00	34.	.01	85.	.64	5115.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	3.0692	7.78	19.81	.14	1083.	.004	33.2	.0106	84.3	.03	215.
HYDRO TRT LT KER	856.23	33.600	.0009	.00	12.62	1.32	10496.	.000	.1	.0000	.3	.17	1325.
HYDRO TRT HY KER	886.85	27.900	.0014	.01	12.27	2.15	17074.	.000	.2	.0031	.5	.26	2096.
TOTAL OUTPUT						3.61	28653.	.00	34.	.01	85.	.46	3635.
LOSS AND UNACCOUNTED FOR						.14	1129.	.00	0.	0.00	0.	.19	1481.

COAL KERO HYDROTREATER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.8	6328.5	2.8	1195.0	2.2	7.6	1.3	.031
FUEL	.1	720.2	48.8	21000.0	4.4	15.1	2.5	.063
POWER					1.2	4.3	.7	.018
HYDROGEN	.3	2205.3	120.2	51667.0	33.4	113.9	18.8	.474
TOTALS					41.3	140.9	23.3	.586

SHALE OIL HYDRO CRACKER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.22	1757.	0.000	0.0	0.0000	0.0	.22	1757.
SHALE GAS OIL	946.53	17.850	.6008	2.00	10.90	8.70	69042.	.052	414.8	.1737	1378.8	.95	7526.
TOTAL INPUT						8.92	70799.	.05	415.	.17	1379.	1.17	9282.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	13.5119	44.91	9.24	.38	3009.	.051	406.5	.1703	1351.3	.04	278.
PROPANE	507.21	147.208	.2803	.93	17.96	.02	148.	.000	.4	.0002	1.4	.00	27.
ISO BUTAE	562.56	119.788	.0326	.11	17.22	.16	1272.	.000	.4	.0002	1.4	.03	219.
N-BUTANE	583.84	110.629	.0895	.29	17.18	.06	468.	.000	.4	.0002	1.4	.01	80.
LIGHT GASOLINE	746.56	57.850	.0055	.02	14.49	1.91	15139.	.000	.8	.0003	2.8	.28	2194.
HEAVY GASOLINE	788.20	47.850	.0083	.03	13.98	1.25	9946.	.000	.8	.0003	2.8	.18	1390.
HYDRO TRT LT KER	810.81	42.850	.0101	.03	13.92	1.56	12361.	.000	1.2	.0005	4.1	.22	1721.
HYDRO TRT HY KER	834.75	37.850	.0132	.06	13.84	.86	6820.	.000	1.2	.0005	4.1	.12	944.
HT SHALEGAS OIL	939.97	23.850	.0123	.04	12.55	2.99	23696.	.000	2.9	.0012	9.7	.37	2975.
TOTAL OUTPUT						9.18	72859.	.05	415.	.17	1379.	1.24	9827.
LOSS AND UNACCOUNTED FOR						-.26	-2060.	.00	0.	.00	0.	-.07	-545.

SHALE OIL HYDRO CRACKER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	2.0	15821.1	2.8	1195.0	5.5	18.9	3.1	.079
FUEL	.2	1601.6	48.8	21000.0	11.1	37.8	6.3	.157
POWER					3.1	10.7	1.8	.044
HYDROGEN	.2	1756.4	120.2	51667.0	26.6	90.7	15.0	.378
TOTALS					46.3	158.1	26.1	.658

COAL OILHYDRO CRACKER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.39	3061.	0.000	0.0	0.0000	0.0	.39	3061.
COAL GASOIL	1003.29	9.400	.1200	.47	10.10	16.07	127514.	.019	153.0	.0755	599.3	1.62	12879.
TOTAL INPUT						16.45	130574.	.02	153.	.08	599.	2.01	15940.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	2.8606	11.20	19.10	.66	5242.	.019	150.0	.0740	587.3	.13	1001.
PROPANE	507.21	147.203	.0325	.13	18.15	.06	471.	.000	.2	.0001	.6	.01	85.
ISO BUTAE	562.56	119.788	.0041	.02	17.24	.47	3754.	.000	.2	.0001	.6	.08	647.
N-BUTANE	583.84	110.623	.0117	.05	17.23	.15	1306.	.000	.2	.0001	.6	.03	225.
LIGHT GASOLINE	740.51	59.400	.0017	.01	14.74	2.22	17630.	.000	.3	.0002	1.2	.33	2594.
HEAVY GASOLINE	803.66	44.400	.0015	.01	13.60	2.51	19918.	.000	.3	.0002	1.2	.34	2709.
HYDRO TRT LT KER	827.17	39.400	.0014	.01	13.44	4.05	32170.	.000	.5	.0002	1.8	.54	4324.
HYDRO TRT HY KER	852.10	34.400	.0019	.01	13.74	2.99	23717.	.000	.5	.0002	1.8	.41	3258.
HT COAL GAS OIL	936.81	19.400	.0041	.02	11.78	3.27	25956.	.000	1.1	.0005	4.2	.39	3059.
TOTAL OUTPUT						16.40	130132.	.02	153.	.08	599.	2.26	17903.
LOSS AND UNACCOUNTED FOR						.06	442.	.00	0.	.00	0.	-.25	-1963.

COAL OILHYDRO CRACKER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	3.5	27566.7	2.8	1195.0	9.7	32.9	5.4	.137
FUEL	.4	3137.4	48.8	21000.0	19.3	65.9	10.9	.274
POWER					5.4	18.6	3.1	.077
HYDROGEN	.4	3060.4	120.2	51667.0	46.3	158.1	26.1	.658
TOTALS					80.7	275.5	45.5	1.147

CATALYTIC REFORMER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
HEAVY NAPTHA	789.18	47.629	.1132	.03	13.81	8.95	71046.	.011	84.0	.0028	22.6	1.24	9811.
HEAVY GASOLINE	784.56	48.683	.0055	.01	14.23	5.21	41360.	.000	2.3	.0005	4.1	.74	5886.
HEAVY GASOLINE	804.30	44.260	.4179	.59	13.44	.78	6219.	.003	26.0	.0046	36.7	.11	836.
TOTAL INPUT						14.95	118624.	.01	112.	.01	63.	2.08	16533.
PRODUCT STREAMS													
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	.26	2046.	0.000	0.0	0.0000	0.0	.26	2046.
ETHANE AND LTR	399.62	222.250	.9477	.54	21.89	.97	7696.	.009	72.9	.0052	41.2	.21	1685.
PROPANE	507.21	147.208	.1950	.11	18.13	1.09	8586.	.002	16.8	.0012	9.5	.20	1556.
ISO BUTAE	562.56	119.788	.3013	.17	17.16	.47	3725.	.001	11.2	.0008	6.3	.08	639.
N-BUTANE	583.84	110.629	.1936	.11	17.19	.74	5886.	.001	11.2	.0008	6.3	.13	1012.
LIGHT GASOLINE	778.87	50.000	0.0000	0.00	13.46	5.17	41020.	0.000	0.0	0.0000	0.0	.70	5521.
HEAVY GASOLINE	864.61	32.000	0.0000	0.00	11.91	5.57	44235.	0.000	0.0	0.0000	0.0	.66	5267.
TOTAL OUTPUT						14.26	113194.	.01	112.	.01	63.	2.23	17726.
LOSS AND UNACCOUNTED FOR						.68	5431.	.00	0.	.00	0.	-.15	-1193.

CATALYTIC REFORMER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
FUEL	1.1	8914.8	48.8	21000.0	54.9	187.2	30.9	.779
POWER					1.3	4.4	.7	.018
HYDROGEN	.3	2045.7	120.2	51667.0	31.0	105.7	17.5	.440
TOTALS					87.1	297.3	49.1	1.237

BUTANE ISOMERIZER MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
N-BUTANE	583.84	110.629	.1000	.10	17.21	1.07	8517.	.001	8.5	.0011	8.5	.18	1466.
TOTAL INPUT						1.07	8517.	.00	9.	.00	9.	.18	1466.
PRODUCT STREAMS													
ETHANE AND LTR	399.62	222.250	0.0000	0.00	22.22	.01	52.	0.000	0.0	0.0000	0.0	.00	11.
PROPANE	507.21	147.208	0.0000	0.00	13.18	.01	46.	0.000	0.0	0.0000	0.0	.00	8.
ISO BUTAE	562.56	119.788	.1022	.10	17.21	1.05	8333.	.001	8.5	.0011	8.5	.18	1434.
TOTAL OUTPUT						1.06	8431.	.00	9.	.00	9.	.18	1454.
LOSS AND UNACCOUNTED FOR						.01	86.	.00	0.	.00	0.	.00	12.

BUTANE ISOMERIZER ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.3	2109.5	2.8	1195.0	.7	2.5	.4	.010
FUEL	.0	144.0	48.8	21000.0	.9	3.0	.5	.013
POWER					.1	.2	.0	.001
TOTALS					1.7	5.8	1.0	.024

ALKYLATION UNIT MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
ISO BUTAE	562.56	119.789	.1000	.10	17.21	.53	4206.	.001	4.2	.0005	4.2	.09	724.
BUTYLENE	604.42	102.384	.1000	.10	14.26	.49	3916.	.000	3.9	.0005	3.9	.07	558.
TOTAL INPUT						1.02	8121.	.00	8.	.00	8.	.16	1282.
PRODUCT STREAMS													
LIGHT ALKYLATE	701.56	70.000	.0317	.03	16.66	.97	7713.	.000	2.4	.0003	2.4	.16	1285.
HEAVY ALKYLATE	738.19	60.000	1.3185	1.32	15.75	.05	432.	.001	5.7	.0007	5.7	.01	68.
TOTAL OUTPUT						1.03	8146.	.00	8.	.00	8.	.17	1353.
LOSS AND UNACCOUNTED FOR						-.00	-25.	-.00	-0.	-.00	-0.	-.01	-71.

ALKYLATION UNIT ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	2.3	18240.5	2.8	1195.0	6.4	21.8	3.6	.091
POWER					.7	2.4	.4	.010
TOTALS					7.1	24.2	4.0	.101

POLYMERIZATION UNIT MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
PROPYLENE	521.50	139.573	.1000	.10	14.26	.74	5876.	.001	5.9	.0007	5.9	.11	838.
BUTYLENE	604.42	102.384	.1000	.10	14.26	.00	0.	.000	.0	.0000	.0	.00	0.
TOTAL INPUT						.74	5876.	.00	6.	.00	6.	.11	838.
PRODUCT STREAMS													
N-BUTANE	583.84	110.629	.0496	.05	17.22	.07	593.	.000	.3	.0000	.3	.01	102.
POLY GASOLINE	778.87	50.000	.0985	.10	13.70	.72	5681.	.001	5.6	.0007	5.6	.10	778.
TOTAL OUTPUT						.79	6275.	.00	6.	.00	6.	.11	881.
LOSS AND UNACCOUNTED FOR						-.05	-399.	-.00	-0.	-.00	-0.	-.01	-43.

POLYMERIZATION UNIT ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	.2	1338.8	2.8	1195.0	.5	1.6	.3	.007
POWER					.1	.5	.1	.002
TOTALS					.6	2.1	.3	.009

HYDROGENPLANT MATERIAL BALANCE REPORT

FEED STREAMS	KG/M 3	(API)	WT PCT SULFUR	WT PCT NITROGEN	WT PCT HYDROGEN	KG/SEC STREAM	(LBS/HR) STREAM	KG/SEC SULFUR	(LBS/HR) SULFUR	KG/SEC NITROGEN	(LBS/HR) NITROGEN	KG/SEC HYDROGEN	(LBS/HR) HYDROGEN
ETHANE AND LTR	399.62	222.250	0.0000	0.00	22.22	.17	1322.	0.000	0.0	0.0000	0.0	.04	294.
PROPANE	507.21	147.208	0.0000	0.00	18.18	1.80	14302.	0.000	0.0	0.0000	0.0	.33	2600.
TOTAL INPUT						1.97	15623.	0.00	0.	0.00	0.	.36	2894.
PRODUCT STREAMS													
HYDROGEN	334.48	291.140	0.0000	0.00	100.00	1.09	8641.	0.000	0.0	0.0000	0.0	1.09	8641.
TOTAL OUTPUT						1.09	8641.	0.00	0.	0.00	0.	1.09	8641.
LOSS AND UNACCOUNTED FOR						.88	6983.	0.00	0.	0.00	0.	-.72	-5747.

HYDROGENPLANT ENERGY CONSUMPTION REPORT

STREAM	KG/SEC	(LBS/HR)	MM JLS/KG	(BTU/LB)	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HR)	PCT REFINERY INPUT
STEAM	-2.5	-20414.0	2.8	1195.0	-7.1	-24.4	-4.0	-.102
FUEL	2.1	17003.9	48.8	21000.0	104.7	357.1	59.0	1.486
POWER					.6	2.0	.3	.008
TOTALS					98.1	334.7	55.3	1.393

TOTAL JET FUEL BLEND AT 525 DEG F ENDPOINT

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	4.3	804.	44.3	.01	.0099	14.13	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	6.6	811.	42.9	.01	.0335	13.92	0.0
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	2.8	814.	42.1	.01	.0028	13.82	0.0
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	3.0	817.	41.5	.04	.0004	13.73	0.0
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	20.7	820.	41.0	.40	.0040	13.60	0.0
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	16.8	827.	39.4	.00	.0056	13.44	0.0
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	5.3	856.	33.6	.00	.0029	12.62	0.0
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	11.6	853.	34.3	.66	1.0100	12.20	0.0
CRUDE UNIT(COAL)	LIGHT KEROSENE	731.	4601.	29.0	923.	21.6	.09	.2900	10.80	0.0
POOL		2527.	15891.	100.0	855.2	33.8	.19	.2115	12.54	0.0

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAPTH WT PCT	AROM WT PCT	HEAT OF JLS/KG	COMBUSTION (BTU/LB)
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	4.3	-41.7	-43.0	29.1	45.0	49.9	5.1	44.	18740.
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	6.6	-45.6	-50.0	25.3	50.0	32.0	18.0	43.	18691.
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	2.8	-45.6	-50.0	23.8	50.0	40.0	10.0	43.	18666.
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	3.0	-29.4	-21.0	22.6	50.1	25.2	24.7	43.	18637.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	20.7	-29.4	-21.0	23.0	47.7	26.3	26.0	43.	18480.
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	16.8	-48.3	-55.0	19.5	50.0	30.0	20.0	43.	18566.
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	5.3	-52.8	-63.0	15.2	30.0	55.0	15.0	43.	18322.
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	11.6	-40.0	-40.0	14.0	30.0	53.0	17.0	43.	18290.
CRUDE UNIT(COAL)	LIGHT KEROSENE	731.	4601.	29.0	-51.1	-60.0	8.0	20.0	30.0	50.0	42.	17860.
POOL		2527.	15891.	100.0	-38.3	-37.0	13.9	36.6	34.3	29.1	43.	18303.

JET FUEL BLEND AT 525 DEG F ENDPOINT AND HYDROGEN CONTENT SPECIFICATION OF 12.80 WT PERCENT

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	4.9	804.	44.3	.01	.0099	14.13	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	7.5	811.	42.9	.01	.0335	13.92	0.0
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	3.2	814.	42.1	.01	.0028	13.82	0.0
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	3.4	817.	41.5	.04	.0004	13.73	0.0
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	23.6	820.	41.0	.40	.0040	13.60	0.0
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	19.1	827.	39.4	.00	.0056	13.44	0.0
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	6.0	836.	33.6	.00	.0029	12.62	0.0
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	13.2	833.	34.3	.66	1.0100	12.20	0.0
CRUDE UNIT(COAL)	LIGHT KEROSENE	424.	2665.	19.1	923.	21.6	.09	.2900	10.80	0.0
POOL		2219.	13956.	100.0	845.7	35.6	.20	.1996	12.80	0.0

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAPTH WT PCT	AROM WT PCT	HEAT OF COMBUSTION JLS/KG	(BTU/LB)
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	4.9	-41.7	-43.0	29.1	45.0	49.9	5.1	44.	18740.
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	7.5	-45.6	-50.0	25.3	50.0	32.0	18.0	43.	18691.
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	3.2	-45.6	-50.0	23.8	50.0	40.0	10.0	43.	18666.
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	3.4	-29.4	-21.0	22.6	50.1	25.2	24.7	43.	18637.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	23.6	-29.4	-21.0	23.0	47.7	26.3	26.0	43.	18480.
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	19.1	-48.3	-55.0	19.5	50.0	30.0	20.0	43.	18566.
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	6.0	-52.8	-63.0	15.2	30.0	55.0	15.0	43.	18322.
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	13.2	-40.0	-40.0	14.0	30.0	53.0	17.0	43.	18290.
CRUDE UNIT(COAL)	LIGHT KEROSENE	424.	2665.	19.1	-51.1	-60.0	8.0	20.0	30.0	50.0	42.	17860.
POOL		2219.	13956.	100.0	-37.2	-34.9	15.4	39.1	35.0	25.9	43.	18370.

TOTAL JET FUEL BLEND AT 650 DEG ENDPOINT

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	1.9	834.	44.3	.01	.0099	14.13	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	2.9	811.	42.9	.01	.0335	13.92	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT HY KER	89.	560.	1.6	835.	37.9	.02	.0607	13.84	8.0
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	1.2	814.	42.1	.01	.0028	13.82	0.0
COAL OILHYDRO CRACKER	HYDRO TRT HY KER	303.	1908.	5.4	852.	34.4	.00	.0076	13.74	8.0
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	1.3	817.	41.5	.04	.0004	13.73	0.0
SHALE KERO HYDROTREATER	HYDRO TRT HY KER	234.	1471.	4.1	838.	37.1	.01	.0187	13.70	8.0
GAS OIL HYDRO CRACKER	DESUL HYKER	70.	443.	1.2	853.	34.1	.01	.0027	13.66	8.0
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	9.2	820.	41.0	.40	.0040	13.60	0.0
DISTILLATE DESULFURIZER	DESUL HYKER	34.	212.	.6	844.	36.0	.05	.0005	13.49	8.0
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	7.5	827.	39.4	.00	.0056	13.44	0.0
CRUDE UNIT(PETROLEUM)	HEAVY KEROSENE	425.	2671.	7.5	854.	34.0	.95	.0100	13.10	8.0
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	2.4	856.	33.6	.00	.0029	12.62	0.0
COAL KERO HYDROTREATER	HYDRO TRT HY KER	210.	1320.	3.7	887.	27.9	.00	.0032	12.27	8.0
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	5.2	853.	34.3	.66	1.0100	12.20	0.0
CRUDE UNIT(SHALE)	HEAVY KEROSENE	623.	3918.	11.0	891.	27.1	.69	1.9009	11.50	6.0
CRUDE UNIT(COAL)	LIGHT KEROSENE	731.	4601.	12.9	923.	21.6	.09	.2900	10.80	0.0
CRUDE UNIT(COAL)	HEAVY KEROSENE	1149.	7226.	20.3	959.	15.9	.14	.3200	10.40	5.0
POOL		5663.	35621.	100.0	880.1	29.1	.26	.3771	12.13	3.6

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAFTH WT PCT	AROM WT PCT	HEAT OF COMBUSTION JLS/KG	(BTU/LB)
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	1.9	-41.7	-43.0	23.8	45.0	49.9	5.1	43.	18666.
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	2.9	-45.6	-50.0	19.5	50.0	32.0	18.0	43.	18566.
SHALE OIL HYDRO CRACKER	HYDRO TRT HY KER	89.	560.	1.6	-45.6	-50.0	32.4	50.0	32.0	18.0	44.	18738.
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	1.2	-45.6	-50.0	23.0	50.0	40.0	10.0	43.	18480.
COAL OILHYDRO CRACKER	HYDRO TRT HY KER	303.	1908.	5.4	-43.3	-55.0	22.8	50.0	30.0	20.0	43.	18606.
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	1.3	-29.4	-21.0	25.3	50.1	25.2	24.7	43.	18691.
SHALE KERO HYDROTREATER	HYDRO TRT HY KER	234.	1471.	4.1	-11.1	12.0	29.6	45.0	49.9	5.1	44.	18713.
GAS OIL HYDRO CRACKER	DESUL HYKER	70.	443.	1.2	-45.6	-50.0	22.3	50.0	40.0	10.0	43.	18594.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	9.2	-29.4	-21.0	23.0	47.7	26.3	26.0	43.	18480.
DISTILLATE DESULFURIZER	DESUL HYKER	34.	212.	.6	-3.9	25.0	26.3	50.1	25.2	24.7	43.	18662.
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	7.5	-48.3	-55.0	15.2	50.0	30.0	20.0	43.	18322.
CRUDE UNIT(PETROLEUM)	HEAVY KEROSENE	425.	2671.	7.5	-3.9	25.0	20.0	47.7	26.3	26.0	43.	18350.
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	2.4	-52.8	-63.0	22.6	30.0	55.0	15.0	43.	18637.
COAL KERO HYDROTREATER	HYDRO TRT HY KER	210.	1320.	3.7	-33.3	-28.0	16.0	30.0	55.0	15.0	43.	18315.
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	5.2	-40.0	-40.0	14.0	30.0	53.0	17.0	43.	18290.
CRUDE UNIT(SHALE)	HEAVY KEROSENE	623.	3918.	11.0	-9.4	15.0	12.0	30.0	53.0	17.0	42.	18100.
CRUDE UNIT(COAL)	LIGHT KEROSENE	731.	4601.	12.9	-51.1	-60.0	8.0	20.0	30.0	50.0	42.	17860.
CRUDE UNIT(COAL)	HEAVY KEROSENE	1149.	7226.	20.3	-31.7	-25.0	7.0	20.0	30.0	50.0	41.	17580.
POOL		5663.	35621.	100.0	-21.9	-7.4	12.1	34.2	36.0	29.8	42.	18152.

JET FUEL BLEND AT 650 DEG F ENDPOINT AND HYDROGEN CONTENT SPECIFICATION OF 12.80 WT PERCENT

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	2.7	804.	44.3	.01	.0039	14.13	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	4.0	811.	42.9	.01	.0335	13.92	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT HY KER	89.	560.	2.2	835.	37.9	.02	.0607	13.84	8.0
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	1.7	814.	42.1	.01	.0028	13.82	0.0
COAL OILHYDRO CRACKER	HYDRO TRT HY KER	303.	1908.	7.3	832.	34.4	.00	.0076	13.74	8.0
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	1.8	817.	41.5	.04	.0004	13.73	0.0
SHALE KERO HYDROTREATER	HYDRO TRT HY KER	234.	1471.	5.7	838.	37.1	.01	.0187	13.70	8.0
GAS OIL HYDRO CRACKER	DESUL HYKER	70.	443.	1.7	853.	34.1	.01	.0027	13.66	8.0
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	12.7	820.	41.0	.40	.0040	13.60	0.0
DISTILLATE DESULFURIZER	DESUL HYKER	34.	212.	.8	844.	36.0	.05	.0005	13.49	8.0
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	10.3	827.	39.4	.00	.0156	13.44	0.0
CRUDE UNIT(PETROLEUM)	HEAVY KEROSENE	425.	2671.	10.3	854.	34.0	.95	.0100	13.10	8.0
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	3.2	856.	33.6	.00	.0029	12.62	0.0
COAL KERO HYDROTREATER	HYDRO TRT HY KER	210.	1320.	5.1	887.	27.9	.00	.0032	12.27	8.0
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	7.1	853.	34.3	.66	1.0100	12.20	0.0
CRUDE UNIT(SHALE)	HEAVY KEROSENE	623.	3918.	15.1	891.	27.1	.69	1.9009	11.50	6.0
CRUDE UNIT(COAL)	LIGHT KEROSENE	346.	2179.	8.4	923.	21.6	.09	.2900	10.80	0.0
POOL		4129.	25973.	100.0	854.0	34.0	.31	.4037	12.80	3.5

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAPTH WT PCT	AROM WT PCT	HEAT OF COMBUSTION JLS/KG	(BTU/LB)
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	2.7	-41.7	-43.0	23.8	45.0	49.9	5.1	43.	18666.
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	4.0	-45.6	-50.0	19.5	50.0	32.0	18.0	43.	18566.
SHALE OIL HYDRO CRACKER	HYDRO TRT HY KER	89.	560.	2.2	-45.6	-50.0	32.4	50.0	32.0	18.0	44.	18738.
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	1.7	-45.6	-50.0	23.0	50.0	40.0	10.0	43.	18480.
COAL OILHYDRO CRACKER	HYDRO TRT HY KER	303.	1908.	7.3	-48.3	-55.0	22.8	50.0	30.0	20.0	43.	18606.
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	1.8	-29.4	-21.0	25.3	50.1	25.2	24.7	43.	18691.
SHALE KERO HYDROTREATER	HYDRO TRT HY KER	234.	1471.	5.7	-11.1	12.0	29.6	45.0	49.9	5.1	44.	18713.
GAS OIL HYDRO CRACKER	DESUL HYKER	70.	443.	1.7	-45.6	-50.0	22.3	50.0	40.0	10.0	43.	18594.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	12.7	-29.4	-21.0	23.0	47.7	26.3	26.0	43.	18480.
DISTILLATE DESULFURIZER	DESUL HYKER	34.	212.	.8	-3.9	25.0	26.3	50.1	25.2	24.7	43.	18662.
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	10.3	-48.3	-55.0	15.2	50.0	30.0	20.0	43.	18322.
CRUDE UNIT(PETROLEUM)	HEAVY KEROSENE	425.	2671.	10.3	-3.9	25.0	20.0	47.7	26.3	26.0	43.	18350.
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	840.	3.2	-52.8	-63.0	22.6	30.0	55.0	15.0	43.	18637.
COAL KERO HYDROTREATER	HYDRO TRT HY KER	210.	1320.	5.1	-33.3	-28.0	16.0	30.0	55.0	15.0	43.	18315.
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	7.1	-40.0	-40.0	14.0	30.0	53.0	17.0	43.	18290.
CRUDE UNIT(SHALE)	HEAVY KEROSENE	623.	3918.	15.1	-9.4	15.0	12.0	30.0	53.0	17.0	42.	18100.
CRUDE UNIT(COAL)	LIGHT KEROSENE	346.	2179.	8.4	-51.1	-60.0	8.0	20.0	30.0	50.0	42.	17860.
POOL		4129.	25973.	100.0	-18.8	-1.9	16.2	40.1	38.5	21.4	43.	18360.

TOTAL JET FUEL BLEND AT 600.0 DEG F ENDPOINT

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	250.	1572.	5.7	825.	39.9	.01	.0152	13.88	4.8
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	220.	1381.	5.0	825.	39.8	.01	.0498	13.97	4.8
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	113.	709.	2.6	838.	37.3	.01	.0028	13.72	4.8
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	606.	3811.	13.7	842.	36.4	.00	.0068	13.62	4.8
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	97.	607.	2.2	833.	38.2	.05	.0005	13.59	4.8
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	778.	4893.	17.6	849.	36.7	.73	.0076	13.30	4.8
COAL KERO HYDROTREATER	HYDRO TRT LT KER	259.	1632.	5.9	875.	30.1	.00	.0031	12.41	4.8
CRUDE UNIT(SHALE)	LIGHT KEROSENE	666.	4188.	15.1	876.	29.9	.68	1.5445	11.78	3.6
CRUDE UNIT(COAL)	LIGHT KEROSENE	1421.	8937.	32.2	945.	18.1	.12	.3080	10.56	3.0
POOL		4409.	27729.	100.0	879.8	29.2	.27	.3444	12.19	4.0

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAPTH WT PCT	AROM WT PCT	HEAT OF JLS/KG	COMBUSTION (BTU/LB)
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	250.	1572.	5.7	-23.3	-10.0	22.6	45.0	49.9	5.1	43.	18484.
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	220.	1381.	5.0	-45.6	-50.0	14.9	50.0	32.0	18.0	42.	18193.
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	113.	709.	2.6	-45.6	-50.0	16.3	50.0	40.0	10.0	43.	18303.
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	606.	3811.	13.7	-48.3	-55.0	16.1	50.0	30.0	20.0	42.	18033.
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	97.	607.	2.2	-14.1	6.6	21.4	50.1	25.2	24.7	43.	18609.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	778.	4893.	17.6	-14.1	6.6	21.2	47.7	26.3	26.0	43.	18402.
COAL KERO HYDROTREATER	HYDRO TRT LT KER	259.	1632.	5.9	-41.1	-42.0	17.6	30.0	55.0	15.0	43.	18366.
CRUDE UNIT(SHALE)	LIGHT KEROSENE	666.	4188.	15.1	-21.7	-7.0	12.8	30.0	53.0	17.0	42.	18176.
CRUDE UNIT(COAL)	LIGHT KEROSENE	1421.	8937.	32.2	-39.4	-39.0	7.4	20.0	30.0	50.0	41.	17692.
POOL		4409.	27729.	100.0	-25.4	-13.7	11.9	34.8	35.6	29.6	42.	18068.

JET FUEL BLEND AT 600.0 DEG F ENDPOINT AND HYDROGEN CONTENT SPECIFICATION OF 12.90 WT PERCENT

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	250.	1572.	7.6	825.	39.9	.01	.0152	13.88	4.8
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	220.	1381.	6.7	825.	39.8	.01	.0498	13.87	4.8
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	113.	709.	3.4	838.	37.3	.01	.0028	13.72	4.8
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	606.	3811.	18.4	842.	36.4	.00	.0068	13.62	4.8
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	97.	607.	2.9	833.	38.2	.05	.0005	13.59	4.8
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	778.	4893.	23.7	840.	36.7	.73	.0076	13.30	4.8
COAL KERO HYDROTREATER	HYDRO TRT LT KER	259.	1632.	7.9	875.	30.1	.00	.0031	12.41	4.8
CRUDE UNIT(SHALE)	LIGHT KEROSENE	666.	4188.	20.3	876.	29.9	.68	1.5445	11.78	3.6
CRUDE UNIT(COAL)	LIGHT KEROSENE	297.	1867.	9.0	945.	18.1	.12	.3080	10.56	3.0
POOL		3285.	20659.	100.0	857.5	33.4	.33	.3591	12.80	4.4

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	FREEZING PT DEG C	(DEG F)	SMK PT MM	PARA WT PCT	NAPTH WT PCT	AROM WT PCT	HEAT OF COMBUSTION JLS/KG	(BTU/LB)
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	250.	1572.	7.6	-23.3	-10.0	22.6	45.0	49.9	5.1	43.	18484.
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	220.	1381.	6.7	-45.6	-50.0	14.9	50.0	32.0	18.0	42.	18193.
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	113.	709.	3.4	-45.6	-50.0	16.3	50.0	40.0	10.0	43.	18303.
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	606.	3811.	18.4	-48.3	-55.0	16.1	50.0	30.0	20.0	42.	18033.
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	97.	607.	2.9	-14.1	6.6	21.4	50.1	25.2	24.7	43.	18609.
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	778.	4893.	23.7	-14.1	6.6	21.2	47.7	26.3	26.0	43.	18402.
COAL KERO HYDROTREATER	HYDRO TRT LT KER	259.	1632.	7.9	-41.1	-42.0	17.5	30.0	55.0	15.0	43.	18366.
CRUDE UNIT(SHALE)	LIGHT KEROSENE	666.	4188.	20.3	-21.7	-7.0	12.8	30.0	53.0	17.0	42.	18176.
CRUDE UNIT(COAL)	LIGHT KEROSENE	297.	1867.	9.0	-39.4	-39.0	7.4	20.0	30.0	50.0	41.	17692.
POOL		3285.	20659.	100.0	-22.4	-8.4	15.0	40.4	37.7	21.9	42.	18210.

TOTAL MIDDLE DISTILLATE FUEL OIL BLEND
(INCLUDING JET FUEL COMPONENTS)

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
COAL KERO HYDROTREATER	HYDRO TRT LT KER	134.	843.	2.3	856.	33.6	.00	.0029	12.62	0.0
COAL KERO HYDROTREATER	HYDRO TRT HY KER	210.	1320.	3.6	887.	27.9	.00	.0032	12.27	8.0
COAL OILHYDRO CRACKER	HYDRO TRT LT KER	424.	2666.	7.2	827.	39.4	.00	.0056	13.44	0.0
COAL OILHYDRO CRACKER	HYDRO TRT HY KER	303.	1908.	5.2	852.	34.4	.00	.0076	13.74	8.0
SHALE KERO HYDROTREATER	HYDRO TRT LT KER	110.	689.	1.9	804.	44.3	.01	.0099	14.13	0.0
SHALE KERO HYDROTREATER	HYDRO TRT HY KER	234.	1471.	4.0	838.	37.1	.01	.0187	13.70	8.0
SHALE OIL HYDRO CRACKER	HYDRO TRT LT KER	166.	1045.	2.8	811.	42.9	.01	.0335	13.92	0.0
GAS OIL HYDRO CRACKER	DESUL HYKER	70.	443.	1.2	853.	34.1	.01	.0027	13.66	8.0
GAS OIL HYDRO CRACKER	HYDRO TRT LT KER	70.	443.	1.2	814.	42.1	.01	.0028	13.82	0.0
SHALE OIL HYDRO CRACKER	HYDRO TRT HY KER	89.	560.	1.5	835.	37.9	.02	.0607	13.84	8.0
KEROSENEHYDRO TREATER	HYDRO TRT LT KER	76.	480.	1.3	817.	41.5	.04	.0004	13.73	0.0
DISTILLATE DESULFURIZER	DESUL HYKER	34.	212.	.6	844.	36.0	.05	.0005	13.49	8.0
DISTILLATE DESULFURIZER	DESUL LTCYCLE	43.	268.	.7	887.	28.0	.08	.0198	11.96	8.0
CRUDE UNIT(COAL)	LIGHT KEROSENE	731.	4601.	12.5	923.	21.6	.09	.2900	10.80	0.0
CRUDE UNIT(COAL)	HEAVY KEROSENE	1149.	7226.	19.6	959.	15.9	.14	.3200	10.40	5.0
CRUDE UNIT(PETROLEUM)	LIGHT KEROSENE	523.	3290.	8.9	820.	41.0	.40	.0040	13.60	0.0
GAS OIL DESULFURIZER	DISTILLATE	1.	5.	.0	843.	36.3	.48	.6812	13.12	8.0
CRUDE UNIT(SHALE)	LIGHT KEROSENE	292.	1837.	5.0	853.	34.3	.66	1.0100	12.20	0.0
CRUDE UNIT(SHALE)	HEAVY KEROSENE	623.	3918.	10.6	891.	27.1	.69	1.9009	11.50	6.0
CRUDE UNIT(PETROLEUM)	HEAVY KEROSENE	425.	2671.	7.2	854.	34.0	.95	.0100	13.10	8.0
GAS OIL DESULFURIZER	DISTILLATE	2.	10.	.0	829.	39.0	1.40	.0828	13.53	8.0
CATALYTIC CRACKER	LIGHT CYCLE OIL	160.	1004.	2.7	898.	26.0	1.57	.3823	11.49	10.0
POOL		5868.	36908.	100.0	880.6	29.0	.29	.3746	12.11	3.8

TOTAL RESIDUAL FUEL OIL BLEND

PROCESS UNIT ORIGIN	STREAM NAME	METER 3 /DAY	(BPD)	COMP VOL PCT	KG/M3	(API)	SULFUR WT PCT	NITROGEN WT PCT	HYDROGEN WT PCT	VISCOSITY BLD INDEX
COAL OILHYDRO CRACKER	HT COAL GAS OIL	302.	1899.	5.1	937.	19.4	.00	.0162	11.78	25.0
SHALE OIL HYDRO CRACKER	HT SHALEGAS OIL	284.	1785.	4.8	910.	23.9	.01	.0407	12.55	25.0
GAS OIL DESULFURIZER	DESUL GAS OIL	10.	62.	.2	919.	22.3	.07	.0940	12.20	25.0
GAS OIL DESULFURIZER	DESUL GAS OIL	22.	139.	.4	903.	25.0	.19	.0114	12.63	25.0
CRUDE UNIT(COAL)	VACUUM BOTTOMS	1064.	6694.	17.9	1111.	-4.3	.31	1.2200	8.50	24.2
CRUDE UNIT(SHALE)	VACUUM BOTTOMS	258.	1623.	4.4	1033.	5.3	.40	3.0600	9.40	31.8
CRUDE UNIT(SHALE)	REDUCED CRUDE	755.	4750.	12.7	957.	16.2	.57	2.1348	10.71	21.6
CRUDE UNIT(SHALE)	SHALE GAS OIL	2003.	12600.	33.8	947.	17.9	.60	1.9971	10.90	20.2
THERMAL CRACKER	HEAVY FUEL	133.	834.	2.2	915.	23.0	1.77	.1052	12.81	15.0
CATALYTIC CRACKER	BOTTOMS	95.	597.	1.6	1145.	-8.0	2.33	.5689	8.15	21.0
CRUDE UNIT(PETROLEUM)	REDUCED CRUDE	666.	4190.	11.2	949.	17.5	2.41	.2657	11.73	22.6
CRUDE UNIT(PETROLEUM)	VACUUM BOTTOMS	338.	2123.	5.7	1022.	6.8	3.67	.5800	10.80	33.0
POOL		5930.	37296.	100.0	985.6	11.9	.91	1.3767	10.52	23.0

OVERALL OIL REFINERY MATERIAL BALANCE REPORT

INPUT STREAMS

CRUDE NAME	FLOW RATE METER 3/DAY	(BPD)	WEIGHT KG/SEC	(LBS/HR)	SULFUR KG/SEC	(LBS/HR)	NITROGEN KG/SEC	(LBS/HR)	HYDROGEN KG/SEC	(LBS/HR)
AGA JARI IRAN	5246.6	33000.	51.7	410468.	.7	5500.	.1	534.	6.7	53361.
PARAHO SHALE OIL	5246.6	33000.	56.9	451297.	.4	3204.	1.1	9026.	6.5	51899.
SYNTHOIL KY COAL	5246.6	33000.	62.4	495310.	.1	1090.	.5	3913.	5.8	45668.
TOTAL CRUDE OILS	15739.7	99000.	171.0	1357076.	1.2	9794.	1.7	13473.	19.0	150928.
PURCHASED HYDROGEN			.0	0.						
TOTAL INPUT	15739.7	99000.	171.0	1357076.	1.2	9794.	1.7	13473.	19.0	150928.

OUTPUT STREAMS

SULFUR REMOVAL	0.0	0.	.3	2247.	.3	2247.				
NITROGEN REMOVAL	0.0	0.	.4	3063.	0.0	0.	.4	3063.		
REFINERY GAS MAKE	328.8	2068.	2.5	20060.	0.0	0.	0.0	0.	.6	4458.
LPG PRODUCT	1.2	7.	.0	56.	0.0	0.	0.0	0.	.0	8.
GASOLINE POOL	3766.0	23688.	32.4	257154.	.3	2068.	.0	45.	4.6	36365.
SPECIFIED JET FUEL	3284.5	20659.	32.6	258441.	.1	841.	.1	926.	4.2	33080.
MIDDLE DISTILLATE	2583.4	16249.	27.2	215686.	.1	555.	.1	851.	3.1	24329.
RESIDUAL FUEL OIL	5929.6	37296.	67.6	536350.	.6	4859.	.9	7384.	7.1	56412.
EXPORT NAPTHA	0.0	0.	.0	0.	.0	0.	.0	0.	.0	
COKE PRODUCT	221.0	1390.	2.7	21799.	.0	264.	.0	374.	.1	436.
KEROSENE SALE	79.5	500.	.8	5960.	.0	2.	.0	0.	.1	818.
DIESEL SALE	79.5	500.	.8	6156.	.0	3.	.0	0.	.1	831.
GAS OIL SALE	0.0	0.	0.0	0.	0.0	0.	0.0	0.	0.0	0.
TOTAL OUTPUT	16273.4	102357.	167.2	1326973.	1.1	8873.	1.6	12642.	19.2	152270.

VOLUME RECOVERY = 103.391
WEIGHT RECOVERY = 97.782
SULFUR RECOVERY = 90.596
NITROGEN RECOVERY = 93.835
HYDROGEN RECOVERY = 100.890

SUMMARY OF REFINERY UNIT OPERATIONS

UNIT	TOTAL FEED RATE M3/DAY	TOTAL FEED RATE (BPD)	TOTAL CAPACITY M3/DAY	TOTAL CAPACITY (BPD)
VAC DIST PETROLEUM	1589.9	10000.0	1589.9	10000.0
VAC DIST SHALE OIL	3179.7	20000.0	3179.7	20000.0
VAC DIST COAL OIL	2959.1	18612.0	3179.7	20000.0
FLUID COKER	794.9	5000.0	794.9	5000.0
CATALYTIC CRACKER	1031.3	6486.7	4769.6	30000.0
THERMAL CRACKER	237.1	1491.4	1589.9	10000.0
GAS OIL DESULFURIZER	34.4	216.2	159.0	1000.0
GAS OIL HYDRO CRACKER	171.9	1081.1	794.9	5000.0
SHALE OIL HYDRO CRACKER	794.9	5000.0	794.9	5000.0
COAL OILHYDRO CRACKER	1385.1	8712.0	1589.9	10000.0
DISTILLATE HYDROCRACKER	159.0	1000.0	159.0	1000.0
DISTILLATE DESULFURIZER	159.0	1000.0	159.0	1000.0
KEROSENEHYDRO TREATER	159.0	1000.0	159.0	1000.0
SHALE KERO HYDROTREATER	318.0	2000.0	318.0	2000.0
COAL KERO HYDROTREATER	318.0	2000.0	318.0	2000.0
CATALYTIC REFORMER	1639.9	10314.6	3179.7	20000.0
ALKYLATION UNIT	126.2	793.8	318.0	2000.0
POLYMERIZATION UNIT	79.5	500.0	79.5	500.0
BUTANE ISOMERIZER	159.0	1000.0	159.0	1000.0
HYDROGENPLANT	1.0	34.8	1.4	50.0

PROCESS UNIT SEVERITY LEVELS

CATALYTIC CRACKER GAS OIL CONVERSION	= 70.0 PERCENT
CATALYTIC REFORMER OCTANE	= 95.0 RON CLEAR
PETROLEUM GAS OIL HYDROCRACKER SEVERITY	=MID DIST OPERATION
SHALE OIL HYDROCRACKER SEVERITY LEVEL	= MEDIUM
COAL OIL HYDROCRACKER SEVERITY LEVEL	= MEDIUM
SHALE OIL KEROSENE HYDROTREATER SEVERITY	= MEDIUM
COAL OIL KEROSENE HYDROTREATER SEVERITY	= MEDIUM

NOTE----- THE PROCESS SUMMARY GIVES THE HYDROGEN PLANT MAKE IN MILLIONS OF CUBIC METERS PER DAY AND MILLIONS OF STANDARD CUBIC FEET / DAY .
RATES SHOWN FOR THE ALKYLATION UNIT CORRESPOND TO THE TOTAL ALKYLATE MAKE.
RATES FOR THE POLYMERIZATION UNIT CORRESPOND TO THE POLYMER GASOLINE MAKE.

OVERALL ENERGY EFFICIENCY REPORT

	MILLION JOULES/SEC	(MILLION) (BTU/HR)	(BBL FOE) (PER HOUR)	PCT REFINERY INPUT
STEAM	51.81	176.79	29.22	.74
FUEL	442.97	1511.49	249.83	6.29
POWER	19.32	65.92	10.90	.27
TOTAL	514.10	1754.20	289.95	7.30
HYDROGEN	192.09	655.44	108.34	2.73

OVERALL REFINERY ENERGY EFFICIENCY(EXCLUDES HYDROGEN)= 92.70 PERCENT

SUMMARY OF REFINERY FUEL AND POWER USAGE

	VOLUME BBLS FOE PER DAY
TOTAL INTERNAL REFINERY FUEL REQUIREMENT	6878.
REFINERY GAS AVAILABILITY	2068.
ADDITIONAL REFINERY FUEL REQUIREMENT	4810.
REFINERY ELECTRICITY REQUIREMENT(THOUSANDS OF KWH)..	464.

GASOLINE POOL REPORT

COMPONENT NAME	VOLUME (BPD)	VOLUME PERCENT	RESEARCH OCTANE NOS 0 ML TEL	3 ML TEL
BUTANES	2837.	12.0	95.0	102.0
PENTANES	1114.	4.7	70.9	89.8
LT HYDROCRACKATE	3067.	12.9	84.5	98.0
STR RUN GASOLINE	3571.	15.1	67.0	87.0
CRACKER GASOLINE	4138.	17.5	92.0	98.0
COKER/VB GASOLINE	505.	2.1	70.0	90.5
POLYMER GASOLINE	500.	2.1	96.0	100.5
ALKYLATE	794.	3.4	93.5	108.3
LT PLATFORMATE	3610.	15.2	92.0	100.0
HVY PLATFORMATE	3507.	14.8	98.0	103.5
DESULF GASOLINE	46.	.2	70.0	80.5
TOTAL POOL	23688.	100.0	87.1	97.5

SUMMARY OF OIL REFINERY ECONOMICS

1...INVESTMENT COSTS

PROCESS UNIT	CAPACITY CU-MT/DAY	CAPACITY (BPD)	INVESTMENT COSTS $/CU-MT/DAY	INVESTMENT COSTS ($/BBL/DAY)	INVESTMENT MILLIONS($)
CRUDE UNIT(TOTAL)	17108.4	107608.7	861.	137.	14.73
VACUUM DIST(TOTAL)	7949.3	50000.0	961.	153.	7.64
CATALYTIC CRACKER	4769.6	30000.0	4789.	761.	22.84
THERMAL CRACKER	1589.9	10000.0	1433.	228.	2.28
KEROSENEHYDRO TREATER	159.0	1000.0	2523.	401.	.40
GAS OIL DESULFURIZER	159.0	1000.0	8445.	1343.	1.34
DISTILLATE DESULFURIZER	159.0	1000.0	3933.	625.	.62
FLUID COKER	794.9	5000.0	7140.	1135.	5.68
DISTILLATE HYDROCRACKER	159.0	1000.0	9247.	1470.	1.47
GAS OIL HYDRO CRACKER	794.9	5000.0	8041.	1278.	6.39
CATALYTIC REFORMER	3179.7	20000.0	3415.	543.	10.86
ALKYLATION UNIT	318.0	2000.0	14285.	2271.	4.54
POLYMERIZATION UNIT	79.5	500.0	6732.	1070.	.54
BUTANE ISOMERIZER	159.0	1000.0	2659.	423.	.42
HYDROGENPLANT	1.4	50.0	6002825.	170000.	8.50
SHALE KERO HYDROTREATER	318.0	2000.0	13843.	2201.	4.40
COAL KERO HYDROTREATER	318.0	2000.0	14167.	2252.	4.50
SHALE OIL HYDRO CRACKER	794.9	5000.0	8041.	1278.	6.39
COAL OILHYDRO CRACKER	1589.9	10000.0	6762.	1075.	10.75

ONSITE INVESTMENT COSTS(PER CALENDER DAY BASIS) 114.30

ONSITE INVESTMENT COSTS(PER STREAM DAY BASIS) 124.24

THE REFINERY COMPLEXITY IS 5.46. OFFSITE FRACTION IS 1.35. OFFSITE INVESTMENT COSTS 167.93

TOTAL INVESTMENT COSTS 292.17

NOTE---HYDROGEN PLANT RATES SHOWN IN THIS ECONOMIC SUMMARYARE IN MILLIONS OF
STANDARD CUBIC METERS AND STANDARD CUBIC FEET PER DAY.

2...OPERATING COSTS

2.1...FIXED COSTS

PROCESS UNIT	CAPACITY CU-MT/DAY	(BBL/DAY)	COSTS($/DAY) LABOR	MAINTENANCE	UNIT TOTAL COSTS $/DAY
CRUDE UNIT(TOTAL)	17108.	107609.	806.	1754.	2560.
VACUUM DIST(TOTAL)	7949.	50000.	1002.	796.	1798.
CATALYTIC CRACKER	4770.	30000.	2545.	2721.	5266.
THERMAL CRACKER	1590.	10000.	1245.	373.	1618.
KEROSENEHYDRO TREATER	159.	1000.	720.	48.	768.
GAS OIL DESULFURIZER	159.	1000.	720.	160.	880.
DISTILLATE DESULFURIZER	159.	1000.	720.	74.	794.
FLUID COKER	795.	5000.	1485.	930.	2415.
DISTILLATE HYDROCRACKER	159.	1000.	1065.	175.	1240.
GAS OIL HYDRO CRACKER	795.	5000.	1065.	761.	1826.
CATALYTIC REFORMER	3180.	20000.	1013.	1294.	2306.
ALKYLATION UNIT	318.	2000.	1050.	744.	1794.
POLYMERIZATION UNIT	79.	500.	585.	69.	654.
BUTANE ISOMERIZER	159.	1000.	1440.	44.	1484.
HYDROGENPLANT	1.	50.	585.	886.	1471.
SHALE KERO HYDROTREATER	318.	2000.	720.	524.	1244.
COAL KERO HYDROTREATER	318.	2000.	720.	537.	1257.
SHALE OIL HYDRO CRACKER	795.	5000.	1065.	761.	1826.
COAL OILHYDRO CRACKER	1590.	10000.	1065.	1281.	2346.
TOTAL FIXED COSTS					34606.

2.2...VARIABLE COSTS(CATALYST,CHEMICALS AND WATER-EXCLUSIVE OF FUEL,POWER AND STEAM)

PROCESS UNIT	FEEDRATE CU-MT/DAY	(BBL/DAY)	COSTS $/CU-MT	($/BBL)	UNIT TOTAL COSTS $/DAY
CRUDE UNIT(TOTAL)	15740.	99000.	.094	.015	1485.
VACUUM DIST(TOTAL)	7729.	48612.	.120	.019	924.
CATALYTIC CRACKER	1031.	6487.	.465	.074	480.
THERMAL CRACKER	237.	1491.	.447	.071	106.
KEROSENEHYDRO TREATER	159.	1000.	.541	.086	86.
GAS OIL DESULFURIZER	34.	216.	.723	.115	25.
DISTILLATE DESULFURIZER	159.	1000.	.723	.115	115.
FLUID COKER	795.	5000.	.182	.029	145.
DISTILLATE HYDROCRACKER	159.	1000.	2.661	.423	423.
GAS OIL HYDRO CRACKER	172.	1081.	2.661	.423	457.
CATALYTIC REFORMER	1640.	10315.	1.151	.183	1888.
ALKYLATION UNIT	125.	794.	6.227	.990	786.
POLYMERIZATION UNIT	79.	500.	1.723	.274	137.
BUTANE ISOMERIZER	159.	1000.	.270	.043	43.
HYDROGENPLANT	1.	35.	0.000	97.000	3513.
SHALE KERO HYDROTREATER	318.	2000.	1.258	.200	400.
COAL KERO HYDROTREATER	318.	2000.	1.258	.200	400.
SHALE OIL HYDRO CRACKER	795.	5000.	2.661	.423	2115.
COAL OILHYDRO CRACKER	1385.	8712.	2.661	.423	3685.
TOTAL VARIABLE COSTS					17213.

NOTE---HYDROGEN PLANT RATES SHOWN IN THIS ECONOMIC SUMMARYARE IN MILLIONS OF

2.3...POWER COSTS

	CENTS/KWH	THOUS-KWH/DAY	$/DAY
TOTAL ELECTRICITY USAGE	2.5	464.1	11601.
TOTAL OPERATING COSTS			63420.

3...CRUDE COSTS

CRUDE OR PURCHASED BLENDING STOCKS	PRICE $/CU-MT	($/BBL)	VOLUME CU-MT/DAY	(BBL/DAY)	COST $/DAY
AGA JARI IRAN	62.90	10.00	5247.	33000.	330000.
PARAHO SHALE OIL	62.90	10.00	5247.	33000.	330000.
SYNTHOIL KY COAL	62.90	10.00	5247.	33000.	330000.
TOTAL VOLUME			15740.	99000.	
TOTAL CRUDE COSTS					990000.

4...PRODUCT SALES

PRODUCT	PRICE $/CU-MT	($/BBL)	VOLUME CU-MT/DAY	(BBL/DAY)	REVENUE $/DAY
FUEL GAS EXPORT	56.61	9.00	329.	2068.	18613.
LPG	66.34	10.50	1.	7.	78.
KEROSENE SALE	92.77	14.75	79.	500.	7375.
DIESEL SALE	86.49	13.75	79.	500.	6875.
GASOLINE	105.67	16.80	3766.	23688.	397952.
JET FUEL BLEND	100.64	16.00	3285.	20659.	330545.
DISTILLATE FUEL	92.46	14.70	2583.	16249.	238858.
RESIDUAL FUEL	77.36	12.30	5930.	37296.	458738.
COKE	50.32	8.00	221.	1390.	11120.
TOTAL REVENUE					1470154.

5...ECONOMIC SUMMARY

	$/DAY	$/CU-MT CRUDE	($/BBL) CRUDE	
REVENUE	1470154.	93.40	14.85	
OPERATING COSTS	63420.	4.03	.64	
CRUDE COSTS	990000.	62.90	10.00	
NET PURCHASED FUEL	43287.	2.75	.44	(NET FUEL PURCHASES OF 4810. BBL FOE/DAY AT 9.00$/BFOE
GROSS PROFIT	373447.	23.73	3.77	
INVESTMENT CARRYING CHARGE*	120069.	7.63	1.21	
NET PROFIT	253377.	16.10	2.56	

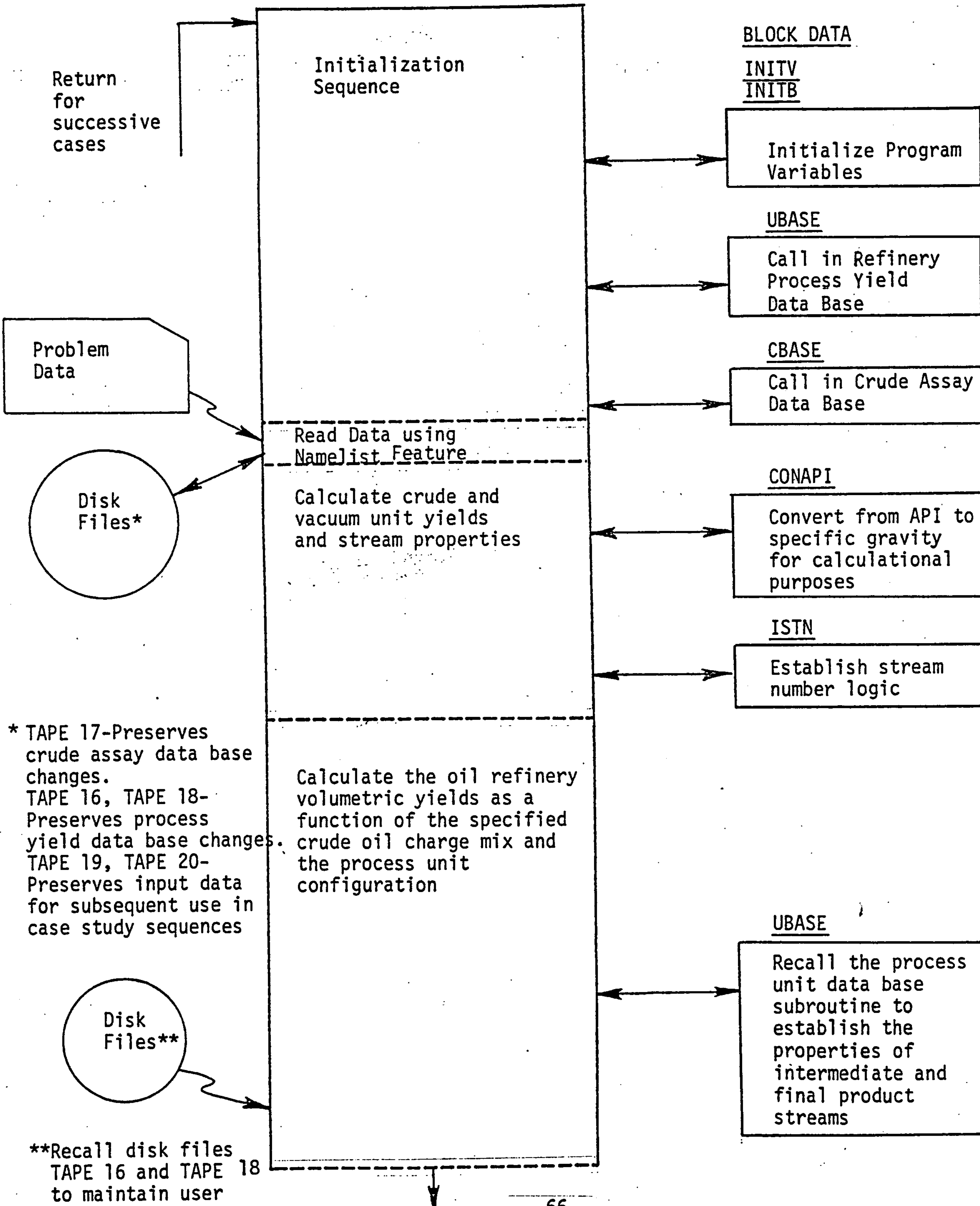
*INVESTMENT CARRYING RATE = 15.00 PERCENT

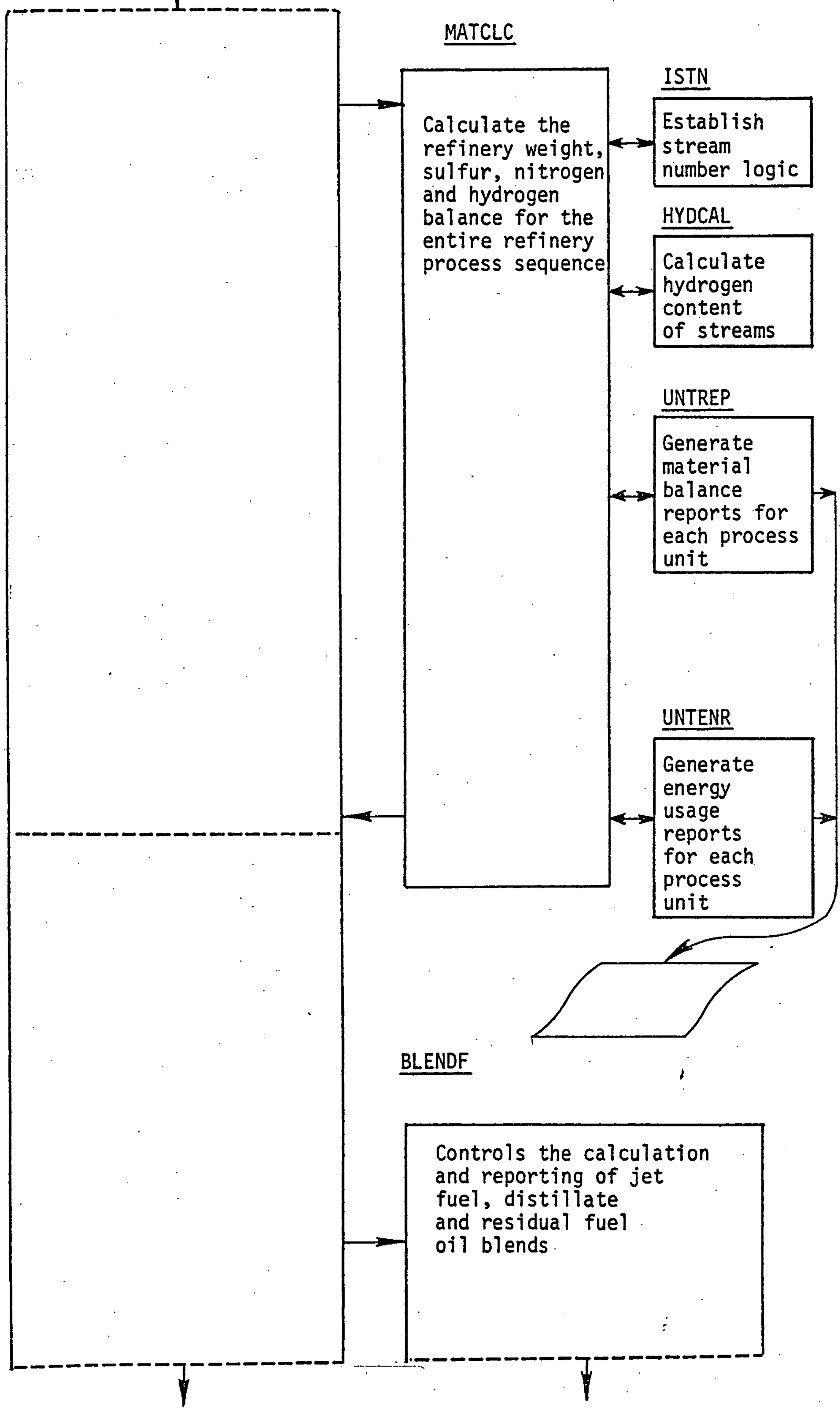
1...INPUT CARD IMAGES

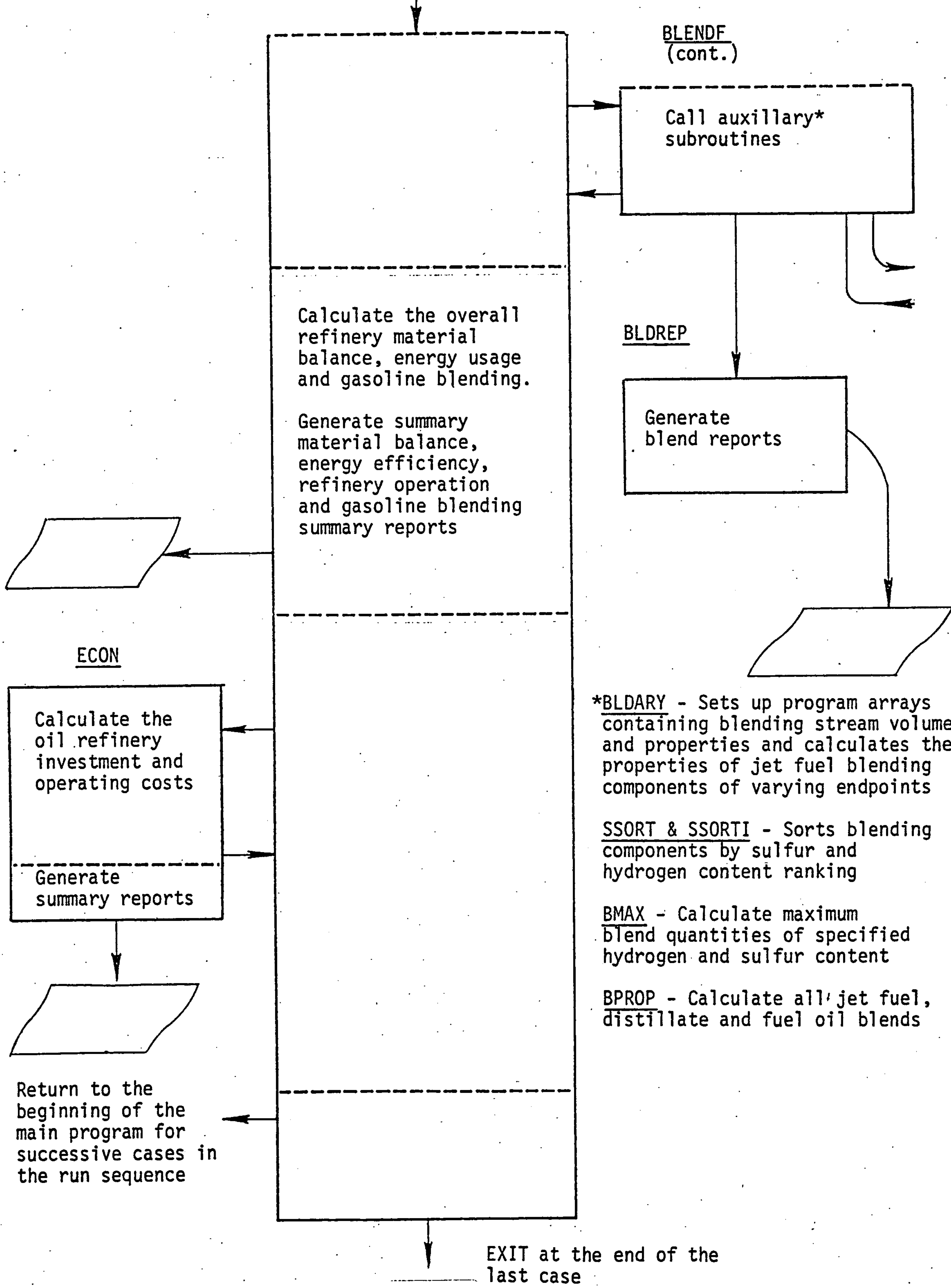
**..AN END OF FILE HAS BEEN REACHED IN THE INPUT CARD STREAM-RUN TERMINATED

EXHIBIT 2 - Block Flow Diagram of Program Logic

MAIN PROGRAM




MATCLC
Calculate the refinery weight, sulfur, nitrogen and hydrogen balance for the entire refinery process sequence
ISTN
Establish stream number logic
HYDCAL
Calculate hydrogen content of streams
UNTREP
Generate material balance reports for each process unit
UNTENR
Generate energy usage reports for each process unit
BLENDF
Controls the calculation and reporting of jet fuel, distillate and residual fuel oil blends



*BLDARY - Sets up program arrays containing blending stream volumes and properties and calculates the properties of jet fuel blending components of varying endpoints

SSORT & SSORTI - Sorts blending components by sulfur and hydrogen content ranking

BMAX - Calculate maximum blend quantities of specified hydrogen and sulfur content

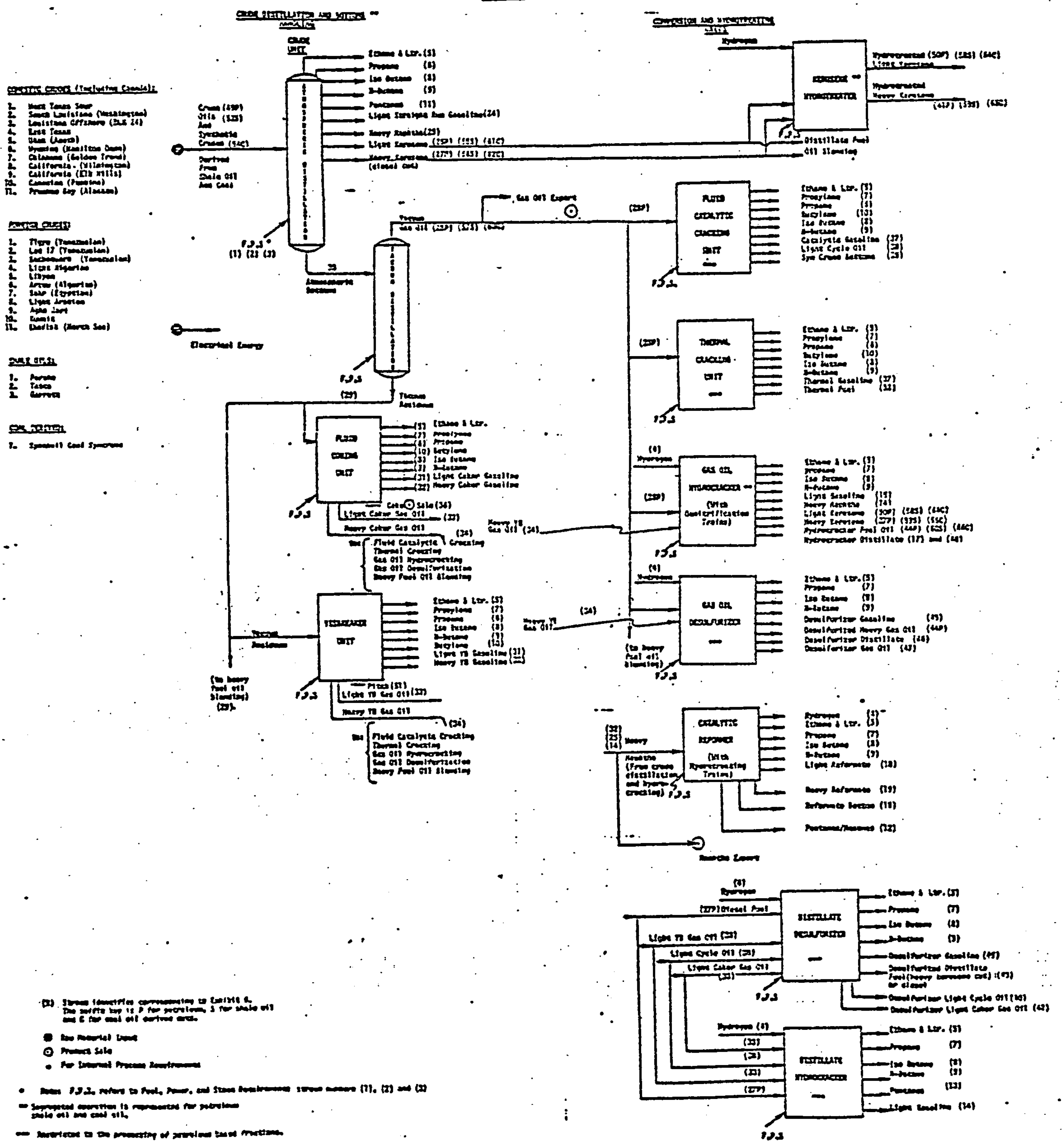
BPROP - Calculate all jet fuel, distillate and fuel oil blends

EXHIBIT 3

REFINERY SIMULATION BLOCK FLOW DIAGRAM

EXHIBIT 2

REFINERY SIMULATION BLOCK FLOW DIAGRAM



(X) Stream identifier corresponding to Exhibit 6. The suffix key is P for petroleum, S for shale oil and C for coal oil derived crude.

Raw Material Input

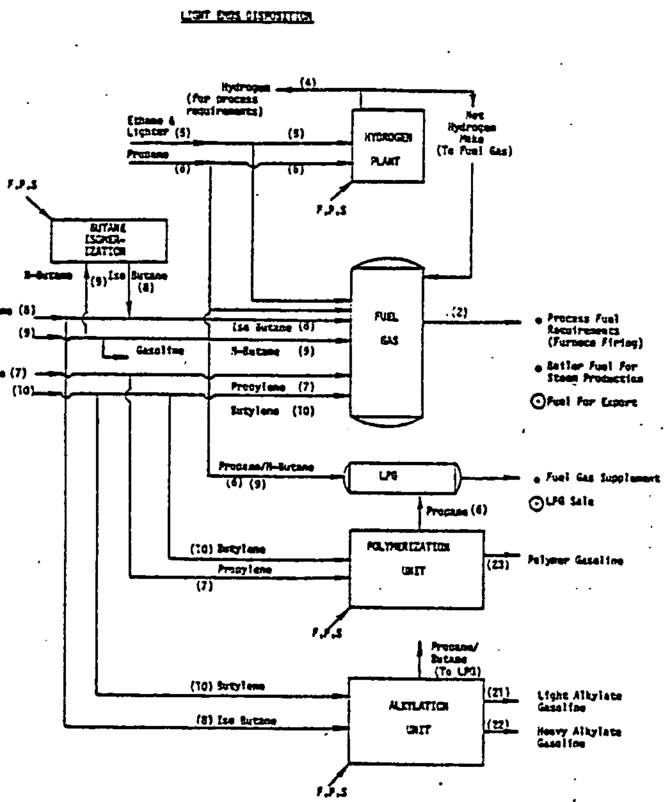
Product Sale

For Internal Process Requirements

* Note: F.P.S. refers to Fuel, Power, and Steam Requirements stream numbers (1), (2) and (3)

** Segregated operation is represented for petroleum shale oil and coal oil.

*** Restricted to the processing of petroleum based fractions.


HYDROGEN PLANT
FUEL GAS
LPG
POLYMERIZATION UNIT
ALKYLATION UNIT
Polymer Gasoline
Light Alkylate Gasoline
Heavy Alkylate Gasoline
LPG Sale
Fuel For Export

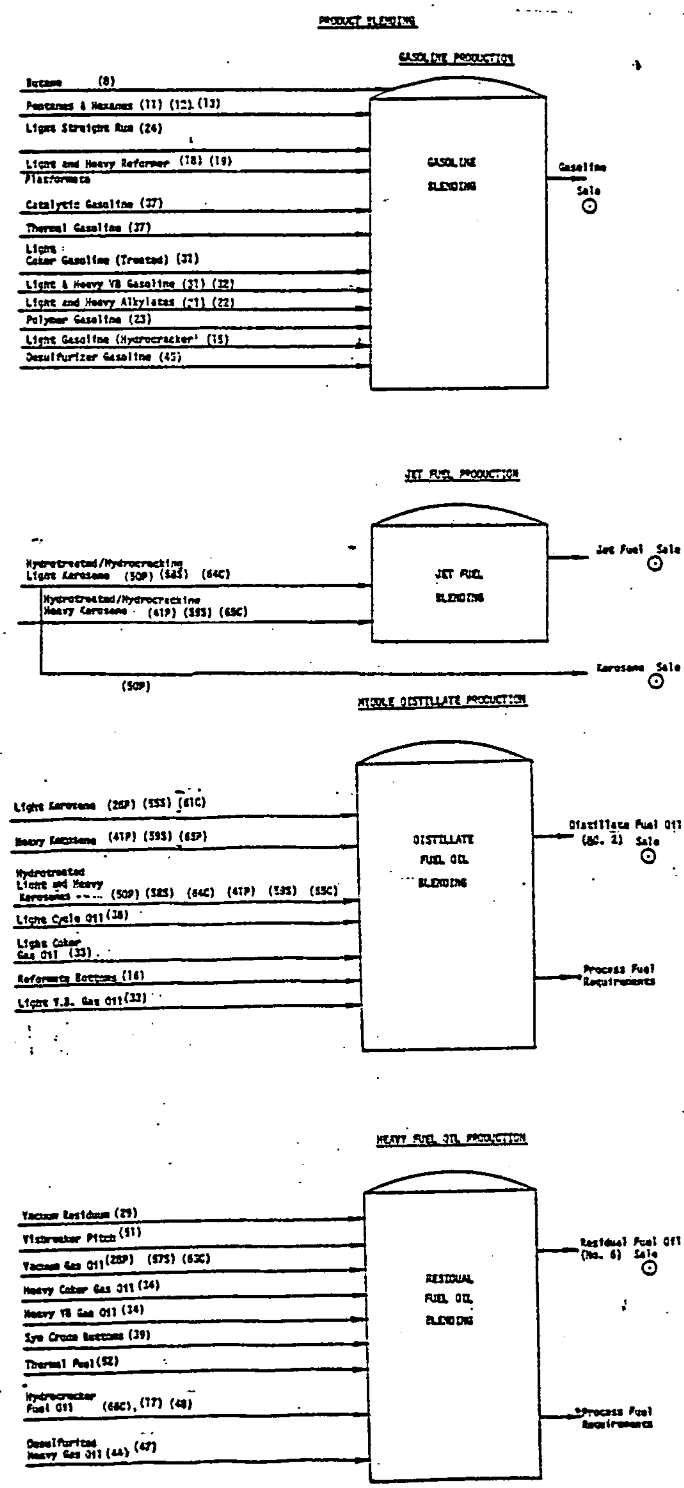

PRODUCT BLENDING
GASOLINE PRODUCTION
GASOLINE BLENDING
Gasoline Sale
JET FUEL PRODUCTION
JET FUEL BLENDING
Jet Fuel Sale
Kerosene Sale
MIDDLE DISTILLATE PRODUCTION
DISTILLATE FUEL OIL BLENDING
Process Fuel Requirements
HEAVY FUEL OIL PRODUCTION
RESIDUAL FUEL OIL BLENDING
Residual Fuel Oil (No. 6) Sale

EXHIBIT 4

LIST OF DATA BASE CRUDE OILS

PROGRAM INPUT IDENTIFICATION CODE	CRUDE OIL		
1	Tigre-Venezuelan -	1.57%S,	24.7 API
2	Lot 17-Venzuelan -	0.98%S,	36.1 API
3	Bachequero-Venezuelan	2.4%S,	16.8 API
4	Nigerian Light -	0.14%S	34.7 API
5	Amal-Libyan -	0.10%S,	35.8 API
6	Arzew-Algerian -	0.10%S,	44.1 API
7	Bakr-Egyptian -	4.4%S,	19.6 API
8	Light Arabian -	1.65%S,	34.2 API
9	Agha Jari-Iranian -	1.34%S,	34.3 API
10	Kuwait -	2.53%S,	31.4 API
11	Paraho Shale Oil -	0.71%S,	19.3 API
12	Tosco Shale Oil -	0.67%S,	21.0 API
13	Garrett Shale Oil	0.64%S,	25.0 API
14	Kentucky Coal Synthoil -	0.22%S,	5.9 API
15	Prudoe Bay Alaska -	1.04%S,	26.8 API
16	Ekofisk-North Sea-Norwegian -	0.18%S,	35.6 API
17	West Texas Sour -	1.9%S,	34.0 API
18	South Lousiiania Ostrica -	0.31%S,	32.3 API
19	Louisiana Delta -	0.30%S,	30.6 API
20	East Texas	0.3%S,	38.0 API
21	Utah Aneth -	0.12%S,	40.9 API
22	Wyoming Sour -	2.4%S,	24.9 API
23	Oklahoma Golden Trend -	0.20%S,	39.9 API
24*	California Elk Hills -	0.61%S,	26.6 API
25	California Wilnington -	1.43%S,	21.7 API
26	Canadian Pembina -	0.83%S,	32.7 API
27-35	Assay Data, as input for additional crude oils		

* Incomplete assay data - do not use without inputing assay data.

EXHIBIT 5

INTERNAL REFINERY STREAM AND PROCESS IDENTIFIERS

Program Identification Number	Description
1	Refinery Steam Consumption
2	Refinery Fuel Consumption
3	Refinery Power Usage
4	Hydrogen (BFOE)
5	Ethane and lighter (BFOE)
6	Propane
7	Propylene
8	Isobutane
9	n-Butane
10	Butylene
11	Pentanes (from crude oil)
12	Reformer Feed Preparation Overhead (C5/C6)
13	Distillate Hydrocracker Pentanes (IC5/NC5)
14	Heavy Hydrocrackate (from both distillate and gas oil)
15	Light Hydrocrackate (from gas oil hydro-cracker)
16	Reformer Feed Preparation Bottoms
17	Distillate product from gas oil hydro-cracker
18	Light Reformate
19	Heavy Reformate
20	Total Reformate
21	Light Alkalate
22	Heavy Alkylate
23	Polymer Gasoline
24	Light Straight Run Gasoline
25	Heavy Straight Run Naphtha
26	Petroleum Light Kerosene
27	Petroleum Heavy Kerosene
28	Petroleum Vacuum Gas Oil
29	Vacuum Bottoms Reduced Crude
30	Reduced Crude
31	Light Coker/Visbreaker Gasoline
32	Heavy Coker/Visbreaker Gasoline
33	Light Coker/Visbreaker Gas Oil
34	Heavy Coker/Visbreaker Gas Oil
35	Total Coker/Visbreaker Gas Oil
36	Coke produced from Coker
37	Full range cracked gasoline (FCC/TCC)

38	Light cycle oil from gas oil cat cracker
39	Tower bottoms from gas oil cat cracker
40	Desulfurized light cycle oil
41	Hydrotreated straight run diesel
42	Desulfurized light coker gas oil
43	Distillate product from Gas Oil desulfurizer
44	Gas oil product from Gas Oil desulfurizer
45	Gasoline byproduct from all desulfurization
46	Stream 43, but with Coker/Visbreaker Feed Source
47	Stream 44, but with Coker/Visbreaker Feed Source
48	Stream 17, but with Coker/Visbreaker Feed Source
49	Composite Petroleum Crude Oil
50	Hydrotreated Petroleum Light Kerosene
51	Visbreaker Pitch
52	Thermal fuel produced from the Gas Oil Thermal cracker (all 400+ material)
53	Composite Shale Oil
54	Composite Coal Syn Crude Oil
55	Shale Oil Light Kerosene
56	Shale Oil Heavy Kerosene
57	Shale Oil Gas Oil
58	Hydrotreated Shale Oil Light Kerosene
59	Hydrotreated Shale Oil Heavy Kerosene
60	Hydrotreated Shale Oil Gas Oil
61	Coal Oil Light Kerosene
62	Coal Oil Heavy Kerosene
63	Coal Oil Gas Oil
64	Hydrotreated Coal Oil Light Kerosene
65	Hydrotreated Coal Oil Heavy Kerosene
66	Hydrotreated Coal Oil Gas Oil

EXHIBIT 5 (cont'd)

INTERNAL PROCESS UNIT IDENTIFIERS

Identification Number	Description
1	Total crude unit capacity
2	Visbreaker
3	Catalytic Cracker (petroleum)
4	Thermal Cracker (petroleum)
5	Alkylation Unit
6	Polymerization Unit
7	Distillate Desulfurizer (petroleum)
8	Gas Oil Desulfurizer (petroleum)
9	Distillate Hydrocracker (petroleum)
10	Gas Oil Hydrocracker (petroleum)
11	Catalytic Reformer
12	Hydrogen Plant
13	Butane Isomerization Unit
14	Fluid Coker
15	Kerosene hydrotreater (petroleum)
16	Crude Unit (petroleum feed)
17	Crude Unit (shale oil feed)
18	Crude Unit (coal oil feed)
19	Shale Oil Hydrocracker (gas oil)
20	Coal Oil Hydrocracker (gas oil)
21	Shale Oil Hydrotreater (kerosene)
22	Coal Oil Hydrotreater (kerosene)

EXHIBIT 6

Linear Viscosity Blending Chart

NOTE: Use this chart at 210°F for use with the Gordian Fuels Blending Model. Conversions may be made from either Saybolt Seconds Universal (SSU) or Saybolt Seconds Furol (SSF) viscosities.

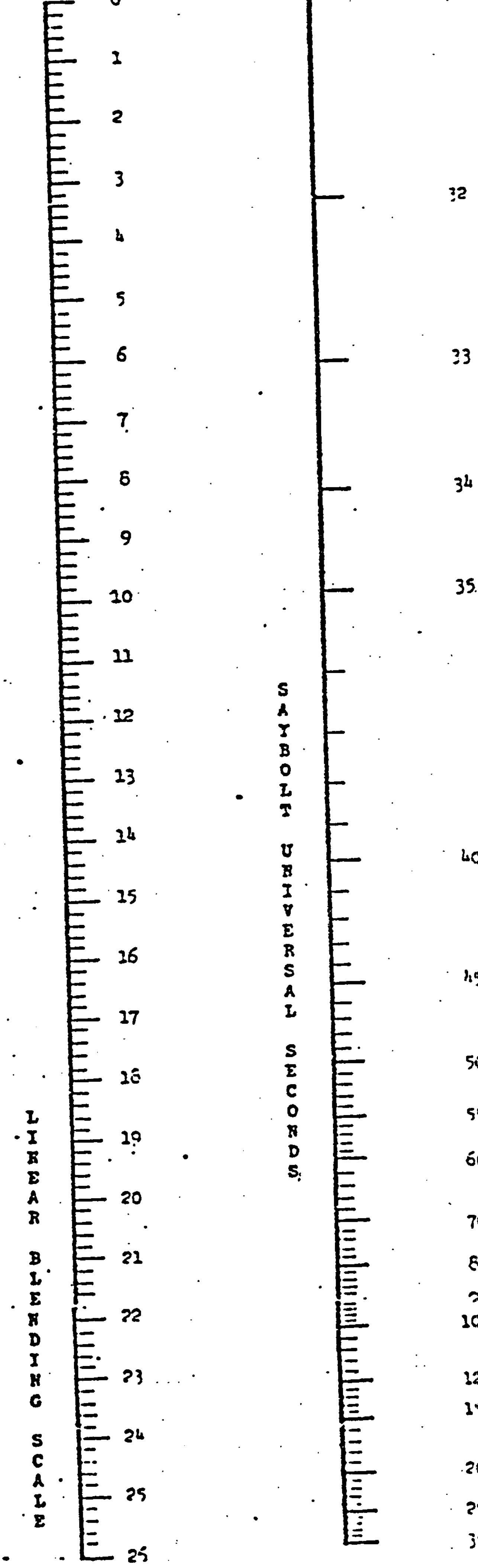


EXHIBIT 6 (cont'd)

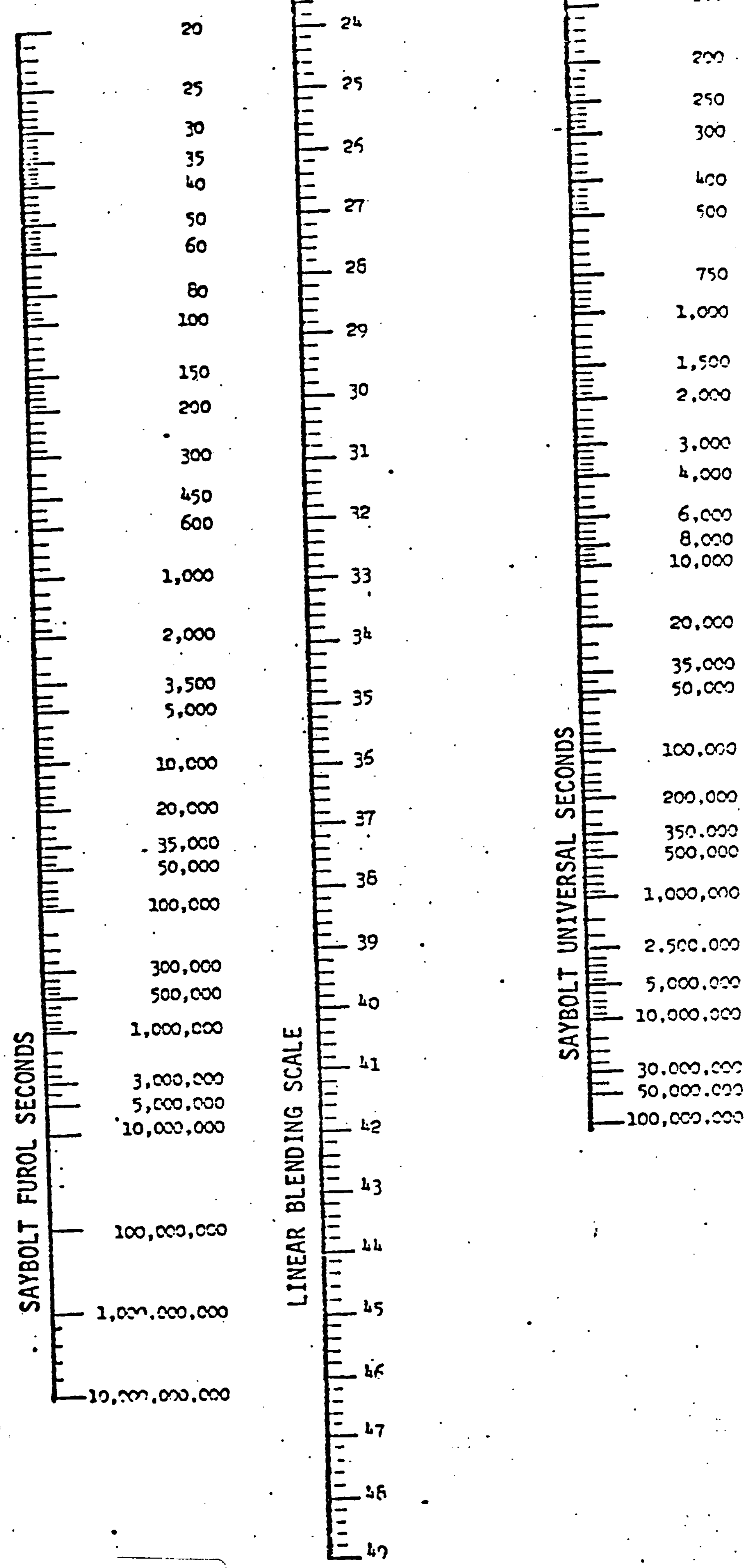


EXHIBIT 7

ECONOMIC DATA BASE

1. CAPITAL INVESTMENT COSTS

The unit capital investment costs (Jan.1, 1977 basis) stored in the economic subroutine are shown below:

Refinery Unit	Unit Capital Investment Cost ($/bpsd)	Reference Unit Size (bpsd)	Source
Atmospheric Distillation	190	20,000	OGJ, Feb. 25, 1974, p.71
Vacuum Distillation	198	20,000	OGJ, Mar. 4, 1974, p.100
Catalytic Gas Oil Cracker	699	40,000	OGJ, Apr. 15, 1974, p.66
Thermal Gas Oil Cracker	185	20,000	OGJ, Apr. 8, 1974, p. 74
Kerosene Hydtrotreater	122	30,000	HP, September, 1976
Gas Oil Desulfurizer	614	50,000	OGJ, Mar.1, 1976 p. 120
Distillate Desulfurizer	267	30,000	HP, September, 1976
Fluid Coking	770	20,000	OGJ, May 24, 1976
Vacuum Bottoms Visbreaker	185	20,000	OGJ, Apr. 8, 1974
Distillate Hydrocracker	747	15,000	HP, September, 1974
Gas Oil Hydrocracker	904	20,000	OGJ, Mar. 25, 1974 p. 120
Catalytic Naphtha Reformer	543	20,000	OGJ, Apr. 22, 1974 p. 130
Alkylation	1193	10,000	OGJ, Apr. 8, 1974 p. 74
Polymerization	800	500	"Gordian Estimate"
Isomerization	222	6,650	HP, September, 1974
Hydrogen Manufacture	170/mscfd	50 mmscfd	OGJ, Mar. 25, 1974 p. 120

2. ECONOMICS OF SCALE

The following power law formula is used in the model to calculate economics of scale.

$$\left(\frac{I_1}{I_2}\right) = \left(\frac{C_1}{C_2}\right)^N$$

Where I, I_2 are investment costs C, C_2 are the corresponding capacities in BPD and N is the power law exponent.

Standard sizes and costs used are given in part (1) above, the power law exponents contained in the model appear on the next page.

Refinery Unit	Capacity Ratio Exponent			
	Hydrocarbon Processing (May, 1975 p.111)	Chemical Engineering (June 15, 1970)	OGJ (see section 5.1.1)	Average*
Atmospheric Distillation	0.70-0.85	0.90	0.77	0.805
Vacuum Distillation	0.70	0.70	0.75	0.717
Catalytic Gas Oil Cracker	0.70	0.55	0.86	0.703
Thermal Gas Oil Cracker		0.70		0.700
Kerosene Hydrotreater		0.65		0.650
Gas Oil Desulfurizer	0.80			0.800
Distillate Desulfurizer	0.65-0.85			0.750
Fluid Coking			0.72	0.720
Vacuum Bottoms Visbreaker		0.65	0.620	0.635
Distillate Hydrocracker	0.75			0.750
Gas Oil Hydrocracker			0.75	0.750
Catalytic Naphtha Reformer	0.70-0.85	0.61	0.80	0.740
Alkylation		0.60	0.60	0.600
Polymerization			0.58	0.580
Isomerization			0.65	0.650
Hydrogen Manufacture	0.65-0.70		0.70	0.680

* The same exponents are assumed for processing shale and coal oil kerosene and gas oil cuts.

3. VARIABLE OPERATING COSTS

The catalyst and chemicals cost figures are in terms of costs per barrel of crude throughput. In order to update the chemicals and catalysts costs, the Nelson-Chemicals Index (Oil and Gas Journal) was used. All chemicals and catalyst costs used in the model are on a Jan. 1, 1977 basis. Water cost were based on an average reported consumption (gal/barrel), at a unit cost assumed to be $0.05/1000 gals.

The total variable operating costs used in the model (chemicals, catalyst, and water) are shown below:

Unit	Variable Cost ($/Bbl)
Atmospheric Distillation	0.015
Vacuum Distillation	0.019
Catalytic Gas Oil Cracker	0.074
Thermal Gas Oil Cracker	0.071
Kerosene Hydrotreater	0.086
Gas Oil Desulfurizer	0.115
Distillate Desulfurizer	0.115
Fluid Coking	0.024
Vacuum Bottoms Visbreaker	0.022
Distillate Hydrocracker	0.423
Gas Oil Hydrocracker	0.423
Catalytic Naphtha Reformer	0.183
Alkylation	0.990
Polymerization	0.274
Isomerization	0.043
Hydrogen Manufacture	0.097 ($/mscf)

The fuel, power and steam consumptions are calculated for each unit based on the data base values contained in subroutine UBASE. Fuel and steam is produced from crude oil and intermediate streams and value is a function of crude oil prices. Electric power usage for the total refinery is calculated by the model and reported in thousands of kilowatt hours per day. The cost of electricity is input in cost per kilowatt hours by the user.

4. FIXED OPERATING COSTS

The fixed operating costs include the labor and maintenance costs. Labor costs are assumed to be independent of throughput, units are assumed to be operated on a 24 hour per day basis. Labor use (men per shift) figures were obtained from A Guide to Refinery Operating Costs, by W.L. Nelson, Petroleum Publishing Company, 1976. Labor rates used were: operators $10.00/hr, supervisors - $12.50/hr. In each case the labor rates are inclusive of benefits.

Maintenance costs are given as a per cent of the corrected onsite unit capital investment cost. The computer model utilizes these maintenance figures to calculate the maintenance cost in dollars per day. The maintenance and labor cost numbers used by the computer are listed below:

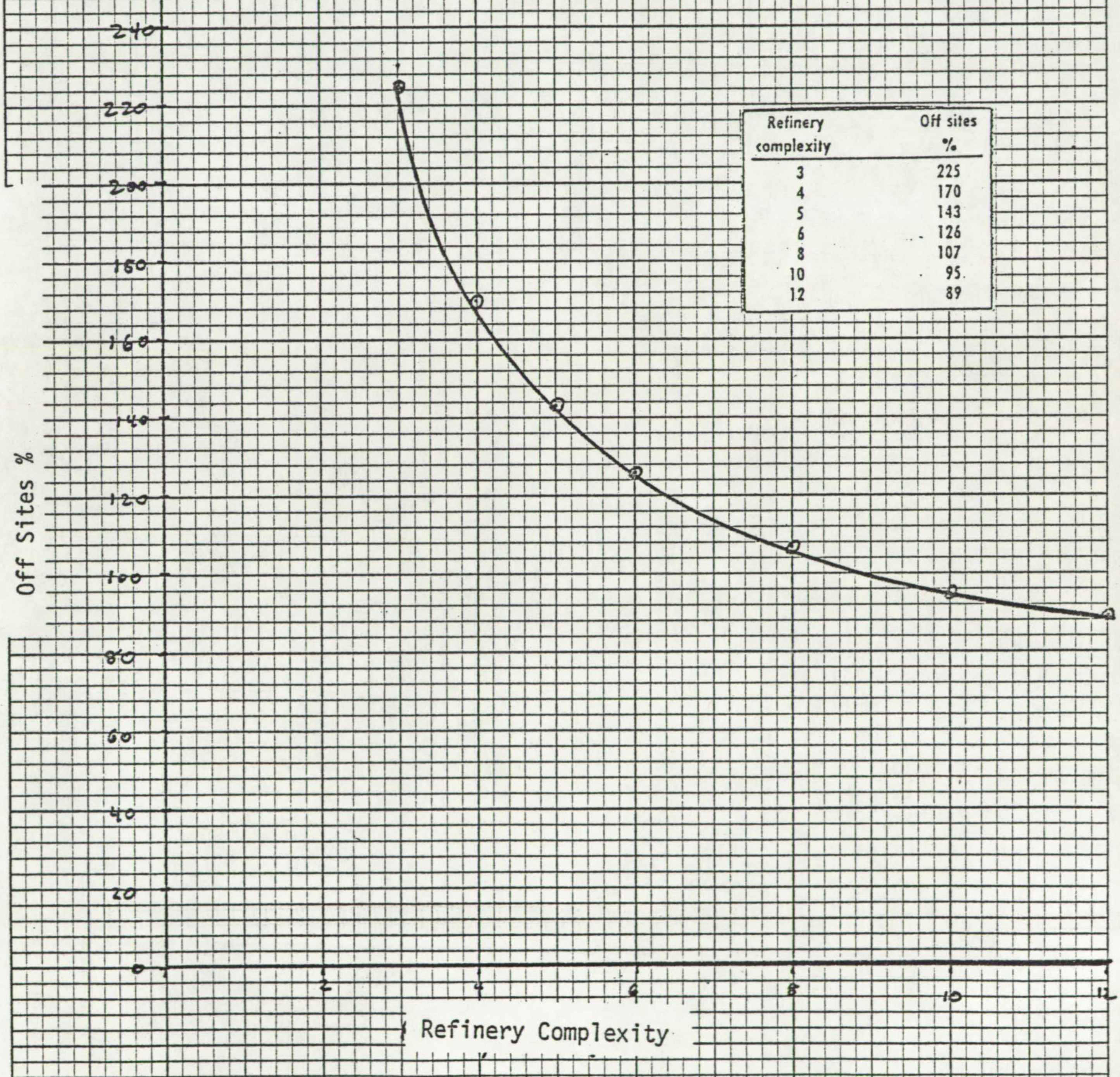
Unit	Labor Cost ($/day)	Maintenance (% Capital Investment Per Annum
Atmospheric Distillation	806.10	4.0
Vacuum Distillation	1002.00	3.5
Catalytic Gas Oil Cracker	1545.00	4.0
Thermal Gas Oil Cracker	1245.00	5.5
Kerosene Hydrotreater	720.00	4.0
Gas Oil Desulfurizer	720.00	4.0
Distillate Desulfurizer	720.00	4.0
Fluid Coking	1485.00	5.5
Vacuum Bottoms Visbreaker	1059.00	4.3
Distillate Hydrocracker	1065.00	4.0
Gas Oil Hydrocracker	1065.00	4.0
Catalytic Naphtha Reformer	1012.50	4.0
Alkylation	1050.00	5.5
Polymerization	505.00	4.3
Isomerization	1440.00	3.5
Hydrogen Manufacture	585.00	3.5

REFINERY OFFSITES

Other refinery investment costs include supporting utilities, tankage, off limits battery piping, roads and accessways, sewers and drains and dock facilities. These are calculated as a function of Nelson refinery using the attached correlation presented by Nelson.

The basic refinery process unit investment is multiplied by the percentage given to obtain the offsites portion of the total investment.

OFF SITES INVESTMENT - AS A % OF ON SITES



Refinery complexity	Off sites %
3	225
4	170
5	143
6	126
8	107
10	95
12	89

EXHIBIT 8

INPUT PRINTOUT FOR SAMPLE BASE CASE AND DEPENDENT CASES

The following page reproduces the computer printout for input representing the feature of base case use with subsequent dependent cases for parametric studies. The first group of images represent the case shown as Exhibit 1; the input ICASE = 1 indicates that this is a base case. The second group represents a subsequent calculation, in which the only change is a requirement of jet fuel production at 575°F end point and 13.0% hydrogen (compared to 600°F and 12.8% in the base case.) The input ICASE=2 indicates that this case is dependent on the preceding ICASE=1 calculation and only the indicated inputs change. The third group represents a second dependent calculation in which 500 BPD each of 0.05 and .10% sulfur middle distillate and 0.3 and .35% sulfur residual fuel oils are to be produced, and maximum volumes of 0.15% sulfur distillate and 0.6% sulfur residual are to be calculated and reported. The input ICASE=3 indicates that this is a dependent study of the preceding ICASE=1, but it terminates the series of dependent cases.

FUELS BLENDING MODEL-GORDIAN ASSOCIATES

1...INPUT CARD IMAGES

```
$FDATA
IREP=1,ICASE=1,
SVSKHT=1,SVCKHT=1,SVSGHT=1,SVCGHT=1,
CV(9)=33000.0,CV(11)=33000.0,CV(14)=33000.0,ALKY=2000.0,EI=1000.0,FCC=50000.0,
CCNV=70.0,VACC=10000.0,GOHYC=5000.0,MODE=2,HTKERO=1000.0,HYC= 50.0,POLY=500.0,
REF=20000.0,REFRON=95.0,TCC=10000.0,COKER=5000.0,VACS=20000.0,VACC=20000.0,
SOKHT=5000.0,CCKHT=5000.0,CGOHYC=15000.0,SGOHYC=8000.0,DIESEL=500.0,KERO=500.0,
OPBBL=70*10.00,IVESTCC=0.15,CENTKWH=2.5,STRF=0.92,PFPR=9.00,
FCBBL=9.00,10.50,15.00,14.75,13.75,13.00,16.80,16.00,14.70,12.30,8.00,9*0.0,
GODES=1000.0,MODES=1000.0,MOHYC=1000.0,EPSPEC=600.0,HDSPEC=12.8,
SPECMD=0.2,
$END
```

FUELS BLENDING MODEL-GORDIAN ASSOCIATES

1...INPUT CARD IMAGES

```
$FDATA
ICASE=2,
EPSPEC=575.0,HDSPEC=13.0,
$END
```

FUELS BLENDING MODEL-GORDIAN ASSOCIATES

1...INPUT CARD IMAGES

```
$FDATA
ICASE=3,
SPM1=.05,SPM2=0.10,SPECMD=0.15,SPR1=0.3,SPR2=.35,SPECRF=0.6,
VM1=500.0,VM2=500.0,VR1=500.0,VR2=500.0,
$END
```